TRANSCANADA PIPELINES LIMITED

1993 ANNUAL REPORT

TABLE OF CONTENTS

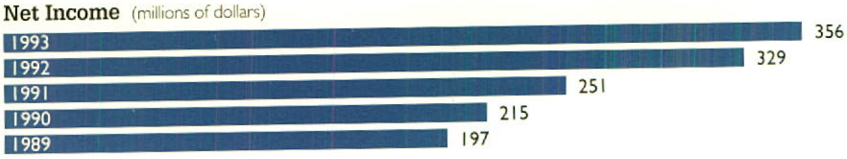
TransCanada PipeLines, a Canadian-based public company with assets of more than $8 billion, is one of North America's leading transporters of natural gas. Its mainline gas transmission system crosses four provinces and the Company is affiliated with three Canadian and three American pipelines, giving TransCanada access to four of North America's major gas markets. The Company has complementary businesses in gas marketing, power generation, gas liquids extraction, gas storage and carbon black manufacturing. In 1993, TransCanada continued to expand its North American pipeline network and pursued natural gas-related investments in the international arena.

Annual Meeting

The 1994 Annual Meeting of Shareholders is scheduled for Friday, April 22, 1994, at 10:30 a.m. in the Palliser Hotel, Calgary, Alberta.

HIGHLIGHTS

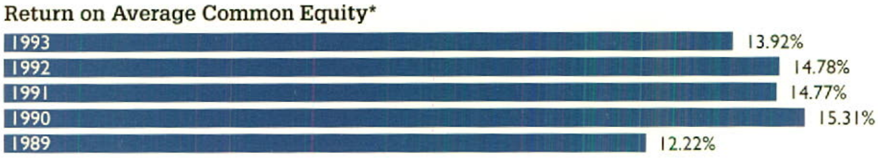
Net Income (millions of dollars)



Funds Generated (millions of dollars)

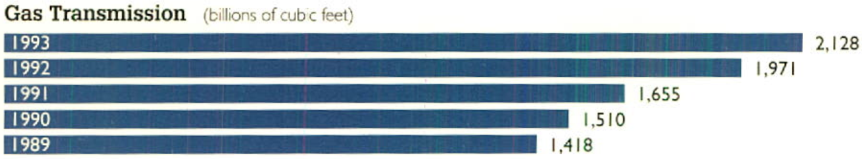
Net Income per Share (dollars per share)

Return on Average Common Equity*

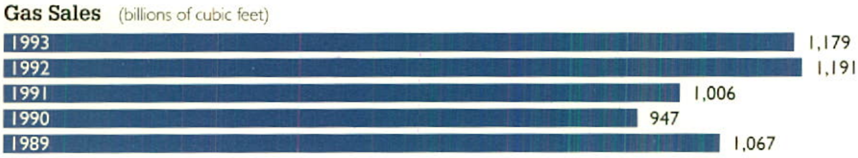


*including Equity Preferred Shares

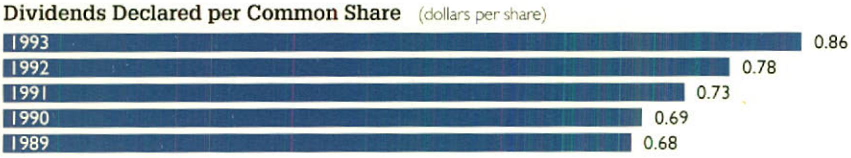
Gas Transmission (billions of cubic feet)



Gas Sales (billions of cubic feet)



Dividends Declared per Common Share (dollars per share)



We are pleased to report that 1993 was a year of continued growth and achievement for TransCanada PipeLines and our shareholders, and marked our fifth consecutive year of increased earnings. It was also the fifth year of a construction cycle that has significantly increased the capacity of our Canadian mainline system. This enables TransCanada to provide transmission customers and natural gas producers with both the required capacity and additional access to markets in eastern Canada and the United States. Mainline growth, however, is slowing and in 1993 TransCanada began to broaden its horizons by pursuing new pipeline and power generation projects in North America and internationally. We believe this new direction is integral to the Company's future growth and will bring ongoing benefits to shareholders.

Pipeline Operating Highlights

In 1993, we again completed a major expansion of our mainline on time and within budget, thus providing the additional gas transmission capability required by both producers and consumers. This brings our investment in the mainline since 1989 to approximately $4.6 billion, making it one of the few mega-projects to benefit the Canadian economy in the early 1990s – with spin-off benefits of close to $9 billion. As a result of the increased capacity, we set a new transmission record in 1993. During the year, TransCanada shipped 2,128 billion cubic feet of natural gas, a 7.9% increase over 1992. As well, expansions undertaken between 1991 and 1993 at the request of our customers on the six Canadian and American pipelines which are affiliated with TransCanada allowed several of our affiliates to experience new highs in transportation volumes.

Gerry Maier, chairman and CEO, and George Watson, president.

Because demand for natural gas and our industry's ability to meet it are now more closely in balance, expansion will continue in 1994 at a slower pace. We project mainline capital expenditures of $460 million this year and, as regulatory approvals are received, moderate expansion on the Iroquois and Alberta Natural Gas systems.

Financial Results

We are pleased that our plans and actions resulted in continuing financial growth for shareholders in 1993, while at the same time, tolls to our customers were maintained at 1992 levels. Net income increased by 8% over 1992 and net income per share continued to improve, ending the year at $1.62, up from $1.56 in 1992. Dividends for common shares also rose for the fifth year in a row, up 10.3% over 1992.

In a year of continuing economic malaise for many North American companies, these are welcome results. They are reflective of business decisions taken over a number of years, heavy capital investment by the Company in our mainline, associated pipelines and electric power generation plants, and the overall strength and positive outlook for the natural gas industry as a whole.

Measuring Our Success

Each year, TransCanada sets goals that act as benchmarks against which we measure our corporate performance. These goals are communicated to employees, who use them as a framework to develop individual and departmental goals. Achievement of the goals in part determines executive compensation. We thought shareholders would be interested in some of our results.

Our primary goals, such as earnings per share, return on equity and return on assets, are financially related and designed to ensure shareholders benefit from their investments. In 1993, we ended up within 1% of all our consolidated corporate financial targets. The Company's mainline accounts for over 80% of its assets and approximately 75% of its income. Consequently, the return on equity set by the National Energy Board (NEB) is a dominant factor in determining our consolidated return. Consolidated return continues to substantially exceed the return allowed by the NEB on our mainline. This underscores the importance and quality of our other business entities, as well as the need to continue adding quality projects to our asset base.

In terms of transportation growth, we measure our progress in becoming the gas transporter of choice by our share of total North American gas deliveries. Our ranking has increased from fifth to second since 1991.

Our safety goal for 1993 was to decrease the frequency of injuries which require mainline employees to take time off work. We have surpassed our goal every year since 1991.

On the environmental front, one of our most challenging goals is to reduce methane emissions. While this target was not met in 1993, our performance in meeting methane emission targets has improved over the last three years and we anticipate further improvement in the future.

Investor confidence in TransCanada is another important yardstick by which we measure our success. To inspire investor confidence, TransCanada must continually demonstrate that shareholders' investments are employed wisely and profitably to support our operations. We have met our goals for return on common equity since 1991. As well, we have maintained A-range credit ratings since 1991, meeting another of our financial strength goals.

Other Interests

Extending our pipeline network is important not only for TransCanada's growth, but for maintaining or improving the integrity of our existing pipeline investments as well. To that end, we now have interests in three proposed U.S. pipelines that will give our system, our customers and gas producers further access to existing markets. The proposed Mayflower system would link to the Iroquois system, which TransCanada operates, to serve the Boston area. The Tuscarora system in Nevada and California would provide a strategic link with the Pacific Gas Transmission (PGT) system; TransCanada expects to begin negotiations regarding the acquisition of PGT in 1994. And we intend to gain a foothold in a new area, the southeastern U.S., by investing with our partners The Coastal Corporation and Florida Power Corporation in the SunShine pipeline to serve Florida.

Natural gas marketing is an important component of TransCanada's business. Our marketing subsidiary, Western Gas Marketing, concluded major organizational and operational changes in 1993 to improve service to its customers as well as efficiency and profitability. The gas marketing business in North America continues to undergo significant change, but we are intent on continuing to help shape that change as well as earn a satisfactory return on our capital.

TransCanada's power generation investments in Rhode Island and Ontario performed well and we expect to finalize plans to construct two new power generation plants at Kapuskasing and North Bay, Ontario, in 1994. We also furthered our interest in the natural gas storage business by participating in proposed projects in Michigan and Alberta, which will enhance the level of service we can offer.

New Ventures

TransCanada's long-term plans – from the mid-'80s to 1993 – generally unfolded as we expected and our vision for the Company remains positive. We have expanded and built the systems required to meet increased U.S. and Canadian demand for natural gas. We have invested in new pipeline and power generation projects in Canada and the United States. Now, with assets of $8 billion, one of the largest pipeline systems in the world and revenues of over $4 billion a year, it is time for TransCanada to look beyond our traditional geographic areas for growth.

North America will continue to be our primary arena of operation, however, because we have the capital, experience and expertise to take advantage of international opportunities, it is incumbent on us to explore these options and find the best investments that will benefit our shareholders in the long term. In 1993, we furthered that process by examining pipeline and power generation opportunities in Latin America, Africa and southeast Asia.

Goals

In 1994, our overall goal is to carefully balance our North American operations and international opportunities. Specifically, our goals are to:

- Continue to provide shareholders with an attractive return.
- Continue to provide North American customers with cost-effective, flexible and competitive natural gas transmission services.
- Continue our ongoing efforts to make our mainline system as safe, environmentally responsible and technologically advanced as it can be.
- Commit funds for mainline and associated pipeline expansion where natural gas demand supports increased capacity.
- Research, develop and consummate pipeline and power generation opportunities outside North America that are consistent with our business strategy and will yield attractive returns for our shareholders.
- Build profits through diversification and expansion of North American natural gas marketing opportunities by introducing innovative pricing, adding value and enhancing relationships with gas producers and customers.
- Balance all of these opportunities – keeping in mind our wish to minimize the need to raise additional common equity – while maintaining our strong financial position.

Changes to the Board and Management

Board member Gordon Osler, who joined our board in 1954 when the pipeline was still a dream on a drawing board, retired in 1993. His counsel and leadership over the years – including his service as chairman from 1984 to 1989 – inspired TransCanada employees and helped build a profitable company. His absence will be felt. George Watson, who was named president of the Company in April 1993, joined the board in August to fill the position created by Mr. Osler's retirement.

TransCanada made several senior management appointments in 1993. Gavin Couper, a senior-vice president, was appointed president of Western Gas Marketing. Craig Frew, Western Gas' president, moved to Connecticut to become president of the Iroquois Pipeline Operating Company, while Iroquois president Robert Reid returned to TransCanada to become senior vice-president. As well, Robert Hodgins was appointed chief financial officer.

Conclusion

One of TransCanada's key success factors is our employees' ongoing commitment to efficiency, safety, environmental responsibility, education and technological innovativeness. These are daily corporate ethics at TransCanada. Without them, we could not enjoy our current level of success. In this Annual Report, the photography highlights our technological expertise to give a sense of our achievements in this area.

Overall, we are very pleased with the Company's competitive position. TransCanada is a leader in the North American natural gas industry. We have the capital, expertise and desire to pursue sound opportunities outside of North America and we look to the future with confidence.

In a time of worldwide economic uncertainty and restructuring, we believe TransCanada PipeLines offers our shareholders stability, continued prosperity and the promise of an exciting future.

Gerald J. Maier, P.Eng., F.C.A.E.
Chairman and Chief Executive Officer

George W. Watson
President

February 24, 1994

In 1993, TransCanada installed 580 kilometres of pipe in four provinces across terrains ranging from the Prairies to the Canadian Shield.

CANADIAN PIPELINES

Canadian Mainline System

Deliveries and Construction

TransCanada PipeLines' Canadian mainline gas transmission system, which began operating in 1957, starts near Empress, Alberta, where western Canadian natural gas is received from the pipeline system operated by NOVA Corporation of Alberta. The mainline crosses Saskatchewan, Manitoba and Ontario, delivering gas to markets along the route, and ends near Montréal, Québec. The TransCanada system interconnects with four Canadian and nine American pipelines to provide further access to North American markets. The Company has easements and other access rights on privately or government-owned lands on which its pipelines are installed, known as rights-of-way. The Company owns all land on which compressor and meter station facilities are located.

In 1993, TransCanada's mainline transported a record amount of natural gas. Total deliveries reached a new high of 2,128 billion cubic feet (Bcf), an increase of 7.9% over 1992. Domestic volumes were 1,205 Bcf, a 6.1% increase over 1992, while export deliveries accounted for 923 Bcf, a 10.4% rise over the same period.

Average daily deliveries reached 5.8 Bcf, up from the previous year's record of 5.4 Bcf.

Since 1989, TransCanada has been expanding its mainline system to meet higher U.S. and Canadian demand for natural gas, injecting approximately $4.6 billion into the Canadian economy. The capacity of the mainline from Alberta to Winnipeg has increased by 50%, while capacity from Winnipeg to Toronto has risen by over 70%. During the year, the Company installed 580 kilometres of pipe and 37.5 megawatts of compression, at a cost of $741 million. This construction enabled TransCanada to increase contracted firm service volumes by approximately 350 million cubic feet per day (MMcf/d).

At the end of 1993, the mainline system comprised 13 687 kilometres of pipe, 1,627 megawatts of compression, 56 compressor stations and 200 meter stations, making it one of the largest natural gas transmission systems in the world.

Regulatory Developments

TransCanada's Canadian pipeline facilities are regulated by the National Energy Board (NEB). Under the terms of the National Energy Board Act (Canada), the NEB regulates the construction and operation of TransCanada's facilities, sets tolls and approves tariffs and the import and export of natural gas.

In October 1993, the NEB approved TransCanada's application for facilities that will be installed in 1994 and 1995. The facilities will cost approximately $397 million and include the installation of 164 kilometres of pipe, seven compressor units and one meter station. The facilities are designed to provide new firm service of 71.8 MMcf/d from western Canada.

TransCanada's pipeline construction expertise allows the Company to consider pipeline projects anywhere in the world. Whether a project calls for a pipe installation across a river (left), or a construction cycle in the dead of winter (right), TransCanada can meet the challenge.

Of this amount, 46% would be for domestic use and 54% for export customers. In addition, the facilities will provide capacity for the shipment of 211.4 MMcf/d of U.S.-sourced gas received in Southern Ontario to Chippawa, Ontario, the delivery point to the Empire State Pipeline in New York.

In March 1993, the NEB approved 1993 mainline tolls based on a 12.25% rate of return on a common equity ratio of 30%, with a revenue requirement of $1.58 billion. In February 1994, the NEB hearing on TransCanada's application for 1994 tolls commenced. In this application, the Company requests a 12.375% return on a common equity ratio of 30%. The NEB's decision is expected in mid-1994. Until then, interim tolls at the 1993 level remain in effect.

Trans Québec & Maritimes Pipeline
(TQM)

TRANSCANADA OWNERSHIP
50%

EQUITY INVESTMENT
$37.9 million

PARTNER
50% Gaz Métropolitain, inc.

DAILY CAPACITY
500 MMcf

LENGTH
342 kilometres (from Saint-Lazare, Québec to west of Québec City)

In 1993, TQM continued to serve markets from Montréal to Québec City. Volumes delivered totalled 113 Bcf, the same level recorded in 1992. During the year, NOVA Corporation of Alberta announced the sale of its 50% interest in TQM to Gaz Métropolitain, inc. effective January 1, 1994. TQM's 12.25% rate of return on a 25% common equity ratio for 1993 and 1994 was approved by the NEB in 1992. There was no construction on the system in 1993 and none is currently planned for 1994.

Foothills Pipe Lines (Sask.) Ltd.
(Foothills (Sask.))

TRANSCANADA OWNERSHIP
44%

EQUITY INVESTMENT
$29.7 million

PARTNERS
51% Foothills Pipe Lines Ltd.
5% Consolidated Pipe Lines Company

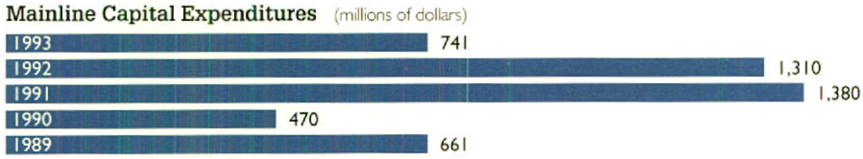
DAILY CAPACITY
1,480 MMcf

LENGTH
259 kilometres (from Empress, Alberta, to Monchy, Saskatchewan)

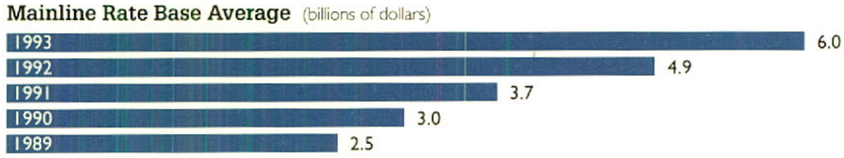
COMPRESSION
117 megawatts

Foothills (Sask.) transports western Canadian natural gas to the Northern Border pipeline, which serves markets in the U.S. midwest. TransCanada operates the pipeline. In 1993, Foothills shipped 485 Bcf, compared to 441 Bcf in 1992, an increase of 10%. The pipeline's 1993 rate of return, as approved by the NEB, was 11.5% on a 28% common equity ratio. There was no construction on the system in 1993, however, the company is installing a stand-by compressor station scheduled to be in service in September 1994. The total cost of this project is approximately $33 million.

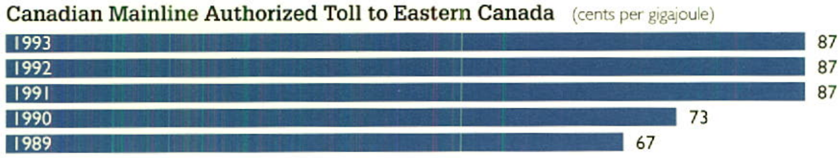
Mainline Capital Expenditures (millions of dollars)



Mainline Rate Base Average (billions of dollars)



Canadian Mainline Authorized Toll to Eastern Canada (cents per gigajoule)



Alberta Natural Gas Company Ltd
(ANG)

TRANSCANADA OWNERSHIP
49.9%

EQUITY INVESTMENT
$149.6 million

DAILY CAPACITY
2,497 MMcf

LENGTH
177 kilometres (from Coleman, Alberta, to Kingsgate, British Columbia)

COMPRESSION
123 megawatts

ANG's pipeline transports natural gas to the British Columbia-United States border, where it is transferred to the Pacific Gas Transmission (PGT) pipeline that serves the U.S. Pacific northwest and California. In 1993, volumes on the ANG system reached 519 Bcf, an increase of 5% over 1992 volumes of 493 Bcf. Together with the connecting Foothills Pipe Lines (South B.C.) Ltd. system, in which ANG has a 49% interest, ANG completed a major system expansion in 1993 to keep pace with expansion on the PGT system. ANG added 42 megawatts of compression, while Foothills (South B.C.) added 78 kilometres of pipe. The $210-million project increased combined system capacity by 897 MMcf/d.

In October 1992, the NEB approved tolls for ANG based on a 12% rate of return on a deemed common equity ratio of 30%. In October 1993, ANG submitted a rates amendment to be effective November 1, 1993, including a 12.50% rate of return on a deemed common equity ratio of 35%. ANG has been operating under interim tolls since that date and has asked the NEB to call a hearing on the matter. ANG has also applied to the NEB to expand two existing compressor stations. If approved, the $52-million modifications would increase capacity at the Canada-U.S. border by 322 MMcf/d. The NEB will hear this application in March 1994.

Information about ANG's other businesses is found on page 19 under the heading "Liquids Extraction and Chemicals."

U.S. PIPELINES

In 1993, U.S. natural gas pipelines continued to be affected by Federal Energy Regulatory Commission (FERC) Order 636, which required interstate pipelines to separate their merchant and transportation functions and provide open-access transportation and storage services. All of TransCanada's U.S. associated pipelines complied with the Order and revised their tariffs accordingly.

Great Lakes Gas Transmission System
(Great Lakes)

TRANSCANADA OWNERSHIP
50%

EQUITY INVESTMENT
$325.2 million

PARTNER
50% Coastal Great Lakes Inc. (Coastal)

DAILY CAPACITY
2,100 MMcf

LENGTH
3 194 kilometres (from the TransCanada system at Emerson, Manitoba, to the TransCanada system at Sarnia, Ontario)

COMPRESSION
345 megawatts

In 1993, Great Lakes continued to expand its system to serve markets in the eastern U.S. and Canada by adding 40 kilometres of pipe and 23 megawatts of compression. These new facilities, costing a total of US$100 million, allowed a capacity increase of 158 MMcf/d. In 1993, Great Lakes transported 854 Bcf of natural gas, an 8% increase over 1992 volumes of 789 Bcf. Of that total, 460 Bcf was transported for redelivery to TransCanada's system in eastern Canada. In 1994, Great Lakes intends to spend approximately US$85.2 million on compressor and pipe replacements.

Great Lakes Gas Transmission Company, owned equally by TransCanada and Coastal, operates the system.

Northern Border Pipeline Company
(Northern Border)

TRANSCANADA OWNERSHIP
30%

EQUITY INVESTMENT
$232.3 million

PARTNER
70% Northern Border Intermediate Limited Partnership

DAILY CAPACITY
1,675 MMcf

LENGTH
1 560 kilometres (from Monchy, Saskatchewan to Harper, Iowa)

COMPRESSION
104 megawatts

Northern Border transports natural gas for producers, marketers and pipeline companies that are active in the U.S. midwest and other regions. In 1993, the pipeline recorded total deliveries of 579 Bcf, an increase of almost 12% over 1992 volumes of 519 Bcf. In 1994, Northern Border plans to examine proposals to extend its system.

Iroquois Gas Transmission System
(Iroquois)

TRANSCANADA OWNERSHIP
29%

EQUITY INVESTMENT
$62.8 million

MAJOR PARTNERS
13.2% Tenneco Gas
11.4% Brooklyn Union Gas Company
10.5% Yankee Energy Systems, Inc.

DAILY CAPACITY
641 MMcf

LENGTH
605 kilometres (from Iroquois, Ontario, to Long Island, New York)

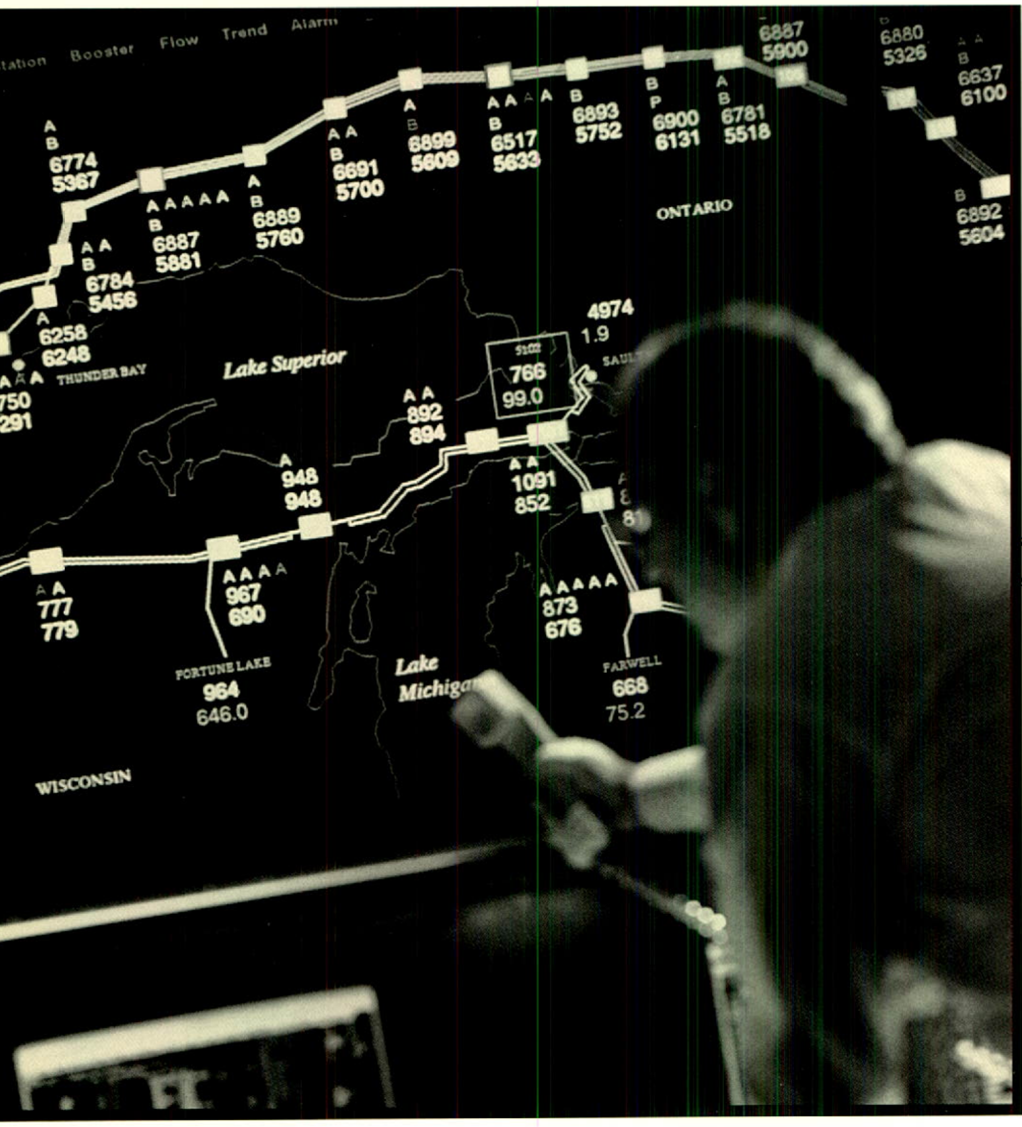
COMPRESSION
8.4 megawatts

In 1993, Iroquois shipped 236 Bcf of natural gas to markets in New York, New England and New Jersey, an increase of 49% over 1992 volumes of 158 Bcf. Along with Canadian natural gas, some U.S. domestic natural gas was also transported on the system. TransCanada's wholly owned subsidiary, Iroquois Pipeline Operating Company, operates the system on behalf of the 12 Iroquois partners.

During the year, Iroquois built three new meter stations and began operating its first compressor station at Wright, New York. Iroquois has filed applications with FERC to add a second compressor station, as well as metering facilities, at a total cost of US$19.0 million. Decisions on the applications are expected in 1994.

TransCanada's Working Interest Share of Capital Expenditures on Associated Pipelines (millions of dollars)


TransCanada Pipelines and Affiliated Systems
Current Pipelines
TransCanada PipeLines
Great Lakes Gas Transmission
Trans Québec & Maritimes
Foothills Pipe Lines (Sask.)
Northern Border Pipeline
Iroquois Gas Transmission
Alberta Natural Gas
Foothills (South B.C.)
Potential Pipelines
Mayflower
SunShine
SunShine Interstate Transmission
Tuscarora
TransCanada has a limited right of first refusal to purchase the Pacific Gas Transmission pipeline.



TransCanada's Gas Control Centre is the hub of the Company's operations. It controls gas flow and is electronically connected to compressor and meter stations on the TransCanada, Great Lakes and Trans Québec & Maritimes systems.

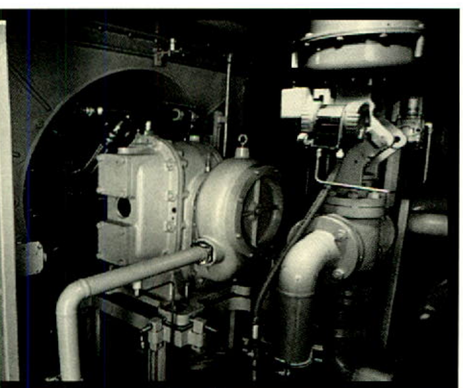
NEW PIPELINE PROJECTS - NORTH AMERICA

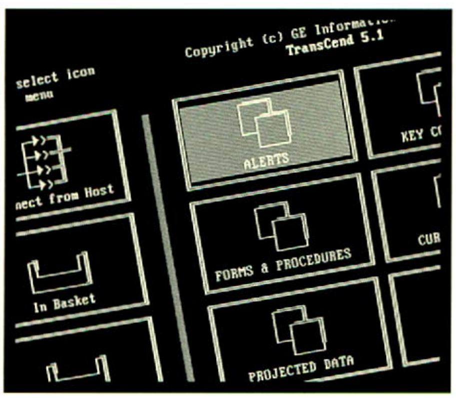
With its interests in Great Lakes and Northern Border, TransCanada has been linking Canadian gas producers and marketers with U.S. customers for many years. In 1993, TransCanada took steps to extend its links to U.S. markets by becoming a partner in three proposed pipelines. Construction is subject to regulatory approvals and the signing of firm contracts.

TransCanada is a 45% partner in the proposed Mayflower Gas Transmission System with The Brooklyn Union Gas Company (10%) and ANR Pipeline Company (45%), a subsidiary of The Coastal Corporation. The 380-kilometre Mayflower System, estimated to cost in the order of US$500 million, would extend east from the Iroquois system in upstate New York to the Boston, Massachusetts area. The Mayflower partnership plans to file a facilities application with FERC in 1995 to meet a proposed in-service date of November 1997.

In the western United States, TransCanada is a 50% partner in the proposed US$125 million Tuscarora pipeline project with Sierra Pacific Resources. A 369-kilometre pipeline, Tuscarora would extend from the Pacific Gas Transmission (PGT) system to serve markets in northern Nevada and northeastern California. A facilities application was filed in August 1993 with FERC. A decision is expected in 1995 and, if favourable, construction would begin shortly thereafter.

TransCanada continues to hold a limited right of first refusal to purchase PGT, owned by Pacific Gas and Electric Company (PG&E), which links the ANG system at the Canada-U.S. border with California markets. PG&E has successfully restructured the gas purchase contracts between its subsidiary Alberta and Southern Gas Co. Ltd. and Canadian gas producers, but remains involved in discussions with the California Public Utilities Commission over cost recoveries. The Company expects to reopen discussions with PG&E once all related issues have been resolved, which should occur sometime during 1994.





New technology enhanced environmental management and customer communications in 1993. TransCanada installed compressors (left) that reduce nitrous oxide emissions at three compressor stations and a new electronic data interchange system linked TransCanada to its customers via computer (right) to reduce fax, mail and long-distance costs.

For the first time, TransCanada became an investor in a southern U.S. project as a 30% partner in the proposed SunShine pipeline project. Other partners in the US$650 million venture are Florida Power Corporation (30%) and The Coastal Corporation (40%). The proposed 1 102-kilometre pipeline will consist of two sections. One section – SunShine Interstate Transmission Company (SITCO) – would extend from Mississippi through Alabama and into Florida. The other – SunShine Pipeline Company (SunShine) – would cross two-thirds of Florida and end near Tampa. SunShine would connect with SITCO and receive all of its gas from that line. In 1993, SITCO filed a FERC facilities application and SunShine received approval to build its system from the Florida Public Service Commission, subject to an environmental review. Construction is expected to take place after required approvals are received.

NATURAL GAS MARKETING

TransCanada's gas marketing operations are carried on by Western Gas Marketing Limited and its subsidiaries and affiliates (collectively known as Western Gas). As agent for TransCanada, Western Gas administers the purchase and sale of natural gas acquired from a large pool of Alberta gas producers, purchases and sells gas on its own behalf and provides transportation and storage services.

In 1993, Western Gas sold a total of 1,179 billion cubic feet (Bcf) of natural gas in North America, a slight decrease from 1992 volumes of 1,191 Bcf. Canadian sales volumes in 1993 accounted for 600 Bcf, or 51% of total sales, while the remaining 579 Bcf, or 49%, were U.S. sales.

Western Gas' producer pool operates through a netback pricing arrangement with 730 gas producers under 2,345 contracts. Netback pricing arrangement transactions represent approximately 90% of the volumes handled by Western Gas. The company estimates that in 1993, under the netback arrangement, it purchased about 25% of all natural gas produced in Canada.

Marketing, regulatory and technological forces combined in 1993 to produce an environment of accelerated change in North American gas marketing. In past years, Western Gas negotiated fixed prices with Canadian local distribution companies every year. In 1993, Western Gas negotiated new pricing with most of those companies, including Consumers' Gas, Union Gas, Centra Gas Ontario and Centra Gas Manitoba, for the remaining terms of existing sales contracts. Under the new terms, prices are indexed to the New York Mercantile Exchange (NYMEX) natural gas commodity price and will vary month-to-month to reflect North American market pricing. The changes allow buyers and sellers to benefit from market-sensitive pricing and make independent pricing decisions through the use of financial tools.

In addition to restructuring pricing, Western Gas also restructured its long-term gas transportation arrangements with NOVA Corporation of Alberta, which operates the major natural gas gathering system in Alberta. The companies agreed to reduce excess gas transportation capacity at certain receipt points to better reflect gas availability in the field. This restructuring does not reduce the volume of gas received by TransCanada from NOVA. It does, however, result in lower unit transportation costs for netback producers.

Western Gas has taken advantage of changes within the industry to concentrate its operations in Calgary and Toronto. A natural gas trading room with computer and telecommunications links to customers, suppliers and pipelines throughout Canada and the U.S. began operating in October 1993. As a result, Western Gas will be terminating operations from its Houston office by mid-1994.

Western Gas and western Canadian gas producers both benefitted from increased North American demand for natural gas in 1993. Western Gas' load factor – the gas the company takes as a percentage of the total supply capability contracted with gas producers – rose from 64% to 93% in 1993. Western Gas began a program to purchase additional gas supply and to encourage drilling on existing contracted lands. At December 31, 1993, the remaining reserves under contract to the company are estimated to be 15,317 Bcf and the reserve life index is estimated to be 13.3 years.

NEW PROJECTS - INTERNATIONAL

In 1993, TransCanada sought out international pipeline and power generation opportunities that complement the Company's technological, financial and managerial capabilities. The Company believes that these types of projects represent logical extensions for corporate growth and will augment TransCanada's long-term viability and continued profitability for its shareholders.

In 1993, the Company researched opportunities in Argentina, Chile and Mexico and bid on proposed pipelines in Colombia and Vietnam. While the Colombia bid was not awarded to TransCanada, the Company is having further discussions with Colombian authorities on other projects. The Company is awaiting a decision on the Vietnamese project.

A bid was prepared and accepted for a venture in Tanzania. The Company, with partner Ocelot Energy Inc. of Calgary, submitted a proposal for a US$200 million project to connect an offshore gas field to a 100-megawatt electric power generation plant in Dar es Salaam through a 220-kilometre pipeline. In January 1994, the Government of Tanzania advised the partners that their initial bid was accepted, which means the partners are now proceeding with exclusive second-round negotiations. If negotiations are successfully completed and acceptable financing arrangements are made in a timely manner, the expected in-service date would be 1996.

Government and energy leaders from around the world are becoming aware of TransCanada's international activities and new projects continue to be brought to the Company's attention. In 1994, TransCanada will continue to assess international opportunities and pursue those which meet Company investment criteria.

TransCanada has successfully merged gas transmission with power generation technology at the Nipigon Power Plant. Nipigon uses natural gas and waste heat from an adjacent TransCanada compressor station to produce electricity. Future power plants planned for Northern Ontario will also use this technology.

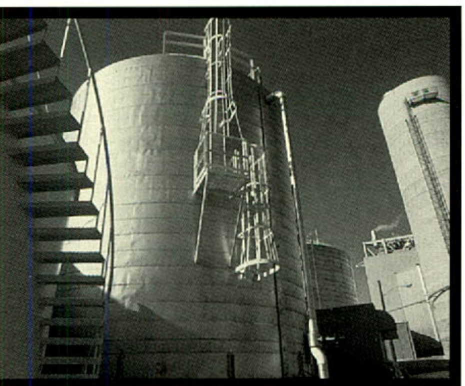
POWER GENERATION

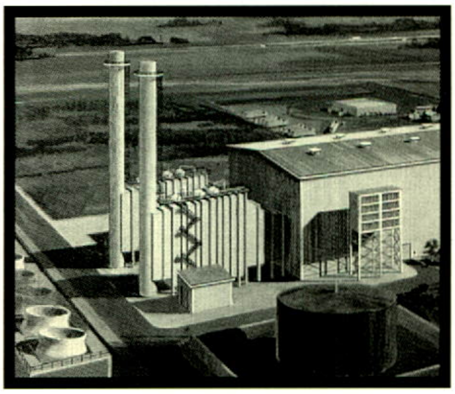
TransCanada has investments in two operating power projects. In 1993, the wholly owned Nipigon Power Plant at Nipigon, Ontario, produced 36 megawatts of electricity per day using energy derived from 6 MMcf/d of western Canadian natural gas and waste heat from an adjacent mainline compressor station.

In the United States, the Company has a 40% interest in the Ocean State Power Plant in Rhode Island, which commenced operation in 1990. TransCanada's equity investment was $107.8 million at December 31, 1993. In 1993, Ocean State produced over 500 megawatts of power a day using 100 MMcf/d of natural gas from Canada.

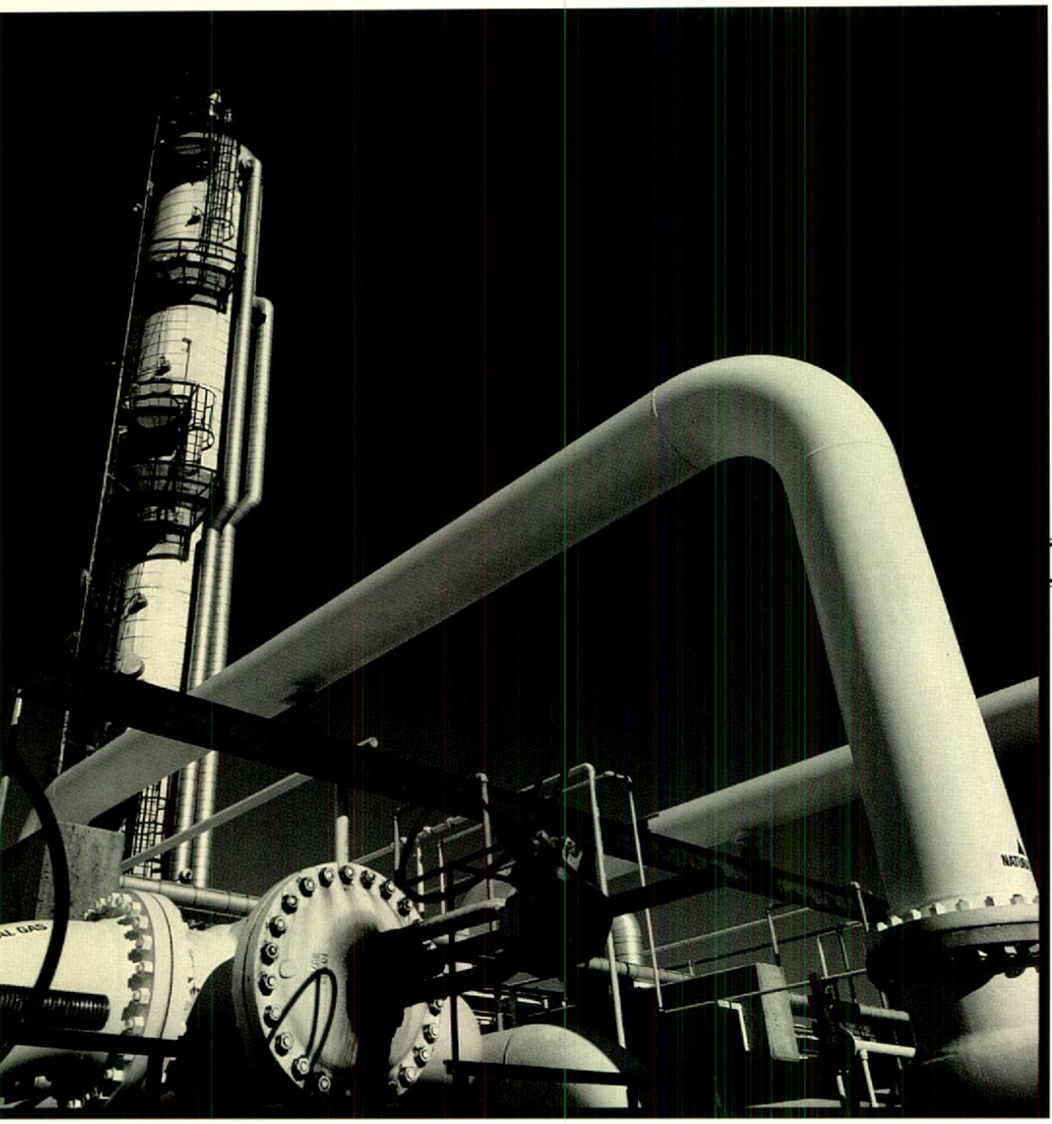
TransCanada is furthering plans to develop power generation plants in North Bay and Kapuskasing, Ontario. As a result of a review by Ontario Hydro, the proposed customer, the size of the plants was scaled back to 40 megawatts each from 150 megawatts. In December, the Company accepted a written offer of power purchase rates from Ontario Hydro. If timely approvals are received, construction would commence in the spring of 1995, with an in-service date of year-end 1996. The plants would use a total of 14 MMcf/d of natural gas and capital costs would be approximately $87 million for each plant. Like the Nipigon facility, the two plants would also utilize waste heat from adjacent Company compressor stations.

The Company is also pursuing a project near Hermiston, Oregon. TransCanada has a one-third interest in a partnership proposing to build a 460-megawatt cogeneration plant called the Hermiston Power Project (Hermiston). It has been selected as one of three energy options by a federal power authority. If the authority selects this option, construction on the first phase of the US$375 million project – a 227-megawatt plant – would begin between 1995 and 2000. Hermiston would use 87 MMcf/d of natural gas delivered by Pacific Gas Transmission.





Ocean State Power (left), in which TransCanada has a 40% interest, uses western Canadian natural gas to produce electricity for half a million people in New England. In 1993, TransCanada joined projects for two proposed plants that would use natural gas to generate power – the Hermiston Power Project in Oregon (right) and a pipeline/power plant venture in Tanzania.



TransCanada owns a 50% interest in the Empress II liquids extraction plant in Alberta. The plant removes propane, butane, ethane and carbon dioxide from natural gas before it enters the TransCanada system.

COMPLEMENTARY BUSINESSES

TransCanada is involved in complementary businesses that promote the sale and use of natural gas. They include gas storage, liquids extraction and medium thermal carbon black manufacturing.

Gas Storage

In October, the Company announced its participation as an equity partner in the proposed US$120 million Washington 10 underground natural gas storage project. This facility in southeast Michigan would hold 42 Bcf of natural gas. TransCanada has a 40% interest in the project; other partners are MCN Corporation (40%), Panhandle Eastern Pipeline Co. (10%) and Union Gas Ltd. (10%). The project will proceed if required regulatory approvals and firm storage contracts are obtained.

TransCanada has also acquired an option to earn a significant interest in the proposed Crossfield East natural gas storage facility in Alberta to be operated by Amoco Canada Petroleum Company Ltd. Crossfield East would have an initial storage capacity of at least 20 Bcf, with the potential to increase to approximately 80 Bcf.

The first stage of the project was the drilling of a horizontal well, which was successfully completed in February 1994.

Liquids Extraction and Chemicals

TransCanada maintains a 50% interest in the Empress II liquids extraction plant on the Alberta/Saskatchewan border.

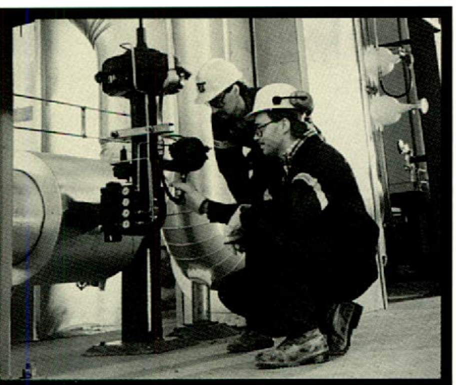
In addition to its pipeline facilities, TransCanada's affiliate Alberta Natural Gas Company Ltd (ANG) has an ethane and liquids extraction plant at Cochrane, Alberta. In 1993, ANG's plant processed 1.2 Bcf/d of gas. ANG received approval from Alberta's Energy Resources Conservation Board to add processing capacity of 900 MMcf/d to the plant.

Through its wholly owned subsidiary ANGUS Chemical Company, ANG is involved in the specialty chemicals business. Products manufactured in the U.S. and Europe are marketed worldwide.

Medium Thermal Carbon Black

Cancarb Limited, a wholly owned subsidiary, manufactures and markets medium thermal carbon black made from natural gas. Its product, Thermax, is used in the manufacture of rubber products, cables, metal carbides and plastics. After record sales in 1992, Cancarb experienced a decrease in sales of 3.5% in 1993 primarily due to economic conditions in Europe. Sales were significantly higher in Japan, Taiwan and Thailand, and the company made its first sale to China.

Cancarb demonstrated its continuing commitment to quality in 1993 and its ISO-9002 certification was renewed by the International Organization for Standardization. This strengthens the company's international marketing position.



TransCanada's affiliate Alberta Natural Gas Company Ltd has a facility at Cochrane, Alberta (left) that extracts natural gas liquids.
In 1993, TransCanada investigated gas storage opportunities to provide additional service to customers. The Company joined a partnership to develop a large natural gas storage facility in Michigan and has an option to acquire an interest in a similar project at Crossfield, Alberta (right).

ENVIRONMENTAL MANAGEMENT

Because TransCanada's ongoing construction and operations activities impact many environmentally sensitive areas – including land, water, air and vegetation – responsible environmental management remains a key corporate ethic. In 1993, TransCanada continued to focus its environmental efforts on compliance with government regulations and corporate standards and improving training and operations programs.

Environmental audits of TransCanada's facilities – part of a three-year program – continued on schedule with 25 audits conducted in 1993. These internal audits assessed TransCanada facilities against some 200 criteria in seven categories, including chemical storage, spill prevention and waste and hazardous materials management. To date, 75% of mainline facilities have been audited, with the remaining 25% scheduled for 1994. In addition, audits were also completed for Foothills Pipe Lines (Sask.) Ltd. and Nipigon Power Plant and assessments were completed for significant proposed property acquisitions. The overall results of the 1993 audit program indicate TransCanada is operating its facilities at a high standard.

In 1993, enhanced training programs heightened awareness of TransCanada's environmental responsibilities. For example, the Company held a sediment control workshop, attended by government officials, construction contractors and employees in North Bay, Ontario. Vegetation management strategies for the right-of-way were introduced for different geographic regions. As well, the existing noise emissions program was strengthened by new guidelines and a database that tracks new concerns and the Company's response to them. Regional environmental plans were also developed and implemented in 1993 to address environmental issues across the TransCanada system.

In 1993, TransCanada was charged with violating laws during one segment of its 1991 construction program. The charges allege that TransCanada allowed sediment to enter several watercourses during construction, which adversely affected other components of the natural environment. The Company denies the allegations and will mount a strong defence. Two U.S. affiliates also dealt with legal matters arising from past activities. For further details, see Note 17 in the section "Consolidated Financial Statements" on page 54.

"Reduce, reuse and recycle" continues to be a strong message at TransCanada. In 1993, the Company implemented a new policy that emphasizes the purchase of products that create as little waste as possible. To set standards for waste reduction, the Company analyzed types and volumes of waste generated by an average compressor station, resulting in a system-wide waste reduction plan that will be implemented in 1994. The goal is to significantly reduce waste at Company facilities within a year.

Environmental Issues Resolved Through Post-construction Monitoring (December 31, 1993)

SAFETY PERFORMANCE

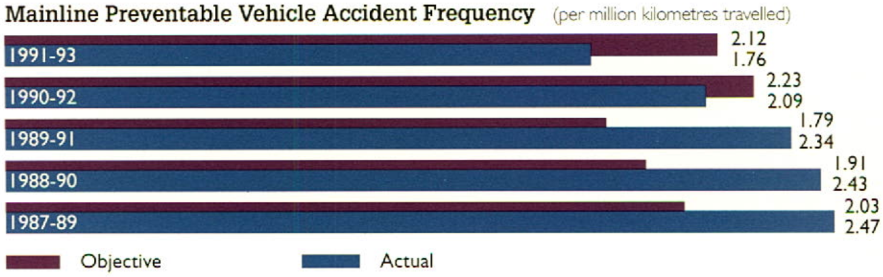
In 1993, TransCanada enjoyed one of its best years ever in terms of safety performance at mainline facilities, achieving the lowest rate in Company history for lost-time accidents and the second lowest level of preventable vehicle accidents.

During the year, TransCanada completed several new initiatives to promote a "work safe" environment, including an employee survey to determine awareness of safety issues and opportunities for improvement. As well, guidance provided by the Company's Corporate Safety Policy Committee led to a continued emphasis by management and employees on improving safety performance and behaviors. Health and safety committees across the system and in head office also provided valuable input to improve employee and facility safety.

Contractor safety also improved during the year. Five years ago, looking ahead to major construction activity, the Company began to encourage compressor station and pipeline contractors to reduce injuries and improve safety performance. In 1993, this program was very successful. The corporate goal was to improve contractor safety by 10% over 1992. In fact, pipeline contractors improved their record by 38% and station contractors by 56%.

Also in 1993, the National Energy Board (NEB) conducted a public inquiry into stress corrosion cracking (SCC) on TransCanada's system, as well as on other Canadian pipeline systems. The inquiry encouraged other pipelines to consider SCC prevention procedures similar to those used by TransCanada, which were deemed to be very effective. TransCanada also launched several research initiatives aimed at further improving SCC detection and prevention techniques.

Mainline Preventable Vehicle Accident Frequency (per million kilometres travelled)



EDUCATION AND TRAINING

The competitive environment in which TransCanada operates demands an employee population that is well trained, productive and technologically innovative. To meet this challenge, TransCanada uses a variety of cost-effective employee development strategies. By making a wide range of internal, external and on-the-job training available to employees, the Company seeks to expand its technical, administrative and managerial skill base, attract highly qualified employees and offer full and challenging careers.

TransCanada estimates that approximately $2 million was invested in employee education and training in 1993. The technical development of the Company's field employees is an important priority and is accomplished through an Operational Training Program. Field employees have access to 85 internal courses in several disciplines, including safety, operations, construction inspection and administration. Head office staff have access to 75 internal courses on supervisory, management and administrative skills, as well as many software courses taught by the Company's Information Systems Department. The Company's Tuition Refund Program reimburses employees who successfully complete job-related, external courses.

TransCanada's commitment to education extends beyond its employees. The Company has a keen interest in developing Canada's youth. In 1993, TransCanada hired 77 cooperative education students from Canadian colleges and universities. The Company endeavours to have these students complete work-terms related to their scholastic disciplines. Native education was supported through short-term and permanent hiring and training initiatives at TransCanada and its affiliate, Polar Gas. Additionally, contributions to educational programs, such as university capital campaigns and endowments, constituted 40% of the corporate donations budget.

The Company has developed a policy that defines TransCanada's objectives and priorities in funding educational institutions and activities. TransCanada supports emerging business/education partnerships at the secondary school level across Canada. This includes Company involvement in specific school partnerships as well as participation in national educational endeavours.

The accompanying consolidated financial statements included in the Annual Report are the responsibility of Management and have been approved by the Board of Directors of the Company. These financial statements of the Company have been prepared by Management in accordance with accounting principles generally accepted in Canada and include amounts that are based on best estimates and judgments. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management has developed and maintains a system of internal accounting controls including a program of internal audits. Management believes the internal accounting controls provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

The Board of Directors has appointed an Audit Committee consisting solely of directors who are not officers of the Company to review with Management and the independent external auditors the annual consolidated financial statements of the Company prior to submission to the Board of Directors for final approval. The Audit Committee also meets periodically during the year with Management and the internal and external auditors individually and as a group. Internal and external auditors have free access to the Audit Committee without obtaining prior Management approval.

The independent external auditors, KPMG Peat Marwick Thorne, have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and changes in financial position in conformity with generally accepted accounting principles.

The report of KPMG Peat Marwick Thorne on page 34 outlines the scope of their examination and their opinion on the consolidated financial statements.

G. J. Maier
Chairman and
Chief Executive Officer

G. W. Watson
President

January 20, 1994

The following discussion has been prepared by Management and is a review of the financial results of the Company based on Canadian generally accepted accounting principles. Its focus is primarily a comparison of TransCanada's financial performance in 1993 and 1992 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 1992 and 1991 are highlighted. Note 18 to the consolidated financial statements describes significant differences between Canadian and United States generally accepted accounting principles.

To provide a better understanding of the Company's regulated operations, definitions of certain terms follow this discussion.

Results from Operations

TransCanada reports its operations under three business segments, the Gas Transmission segment, the Gas Marketing segment and the Associated Operations and Other segment. The Company's Gas Transmission segment, also known as the Canadian mainline system, is regulated by the National Energy Board (NEB). The Canadian mainline system includes over 13 600 kilometres of natural gas transmission pipelines and 56 compressor stations stretching across Canada from the Alberta/Saskatchewan border into Québec. The Company has equity ownership interests in other gas transmission systems which are included in the Associated Operations and Other segment. These systems integrate the Company's Canadian mainline system into a North American network of natural gas pipelines. Affiliation with these associated systems allows the Company to serve markets in Québec and the northeast, midwest, northern California and Pacific northwest regions of the United States. All of these associated operations are also subject to the jurisdiction of various regulatory bodies concerning matters such as tolls, construction, operations and accounting.

Net income for the Company in 1993 was $355.6 million, or $1.62 per share, compared to $328.7 million, or $1.56 per share, for 1992. Net income for the year ended 1991 was $251.2 million, or $1.34 per share. Expansion within the Gas Transmission segment and improved results from several associated United States operations have provided a significant improvement in earnings in the past three years, offset somewhat by lower allowed rates of return on common equity.

Funds generated from operations were $477.5 million in 1993 compared to $486.9 million in 1992. This decrease resulted from higher undistributed earnings of associated pipeline operations and from deferred income taxes.

Gas Transmission Segment

The NEB sets tolls for the Gas Transmission segment which permit the opportunity to recover projected costs of transporting natural gas and provide a fair and reasonable return on the Company's investment in rate base. Factors considered in setting approved tolls include estimating the level of this segment's rate base, as well as operating and financing costs. New facilities must be approved by the NEB before construction begins. Changes in rate base and the rate of return on common equity will affect the contribution to net income by this segment. Most of the operating costs of the Canadian mainline system are fixed and are recovered monthly from shippers on the system.

During 1993, the Company continued to add significantly to its rate base by constructing over $740 million of additional pipeline and compression facilities, which compares to $1.3 billion in 1992 and $1.4 billion in 1991. The segment's actual average rate base for 1993, 1992 and 1991 amounted to approximately $6.0 billion, $4.9 billion and $3.7 billion, respectively, and the Company's earnings reflect that level of rate base. At December 31, 1993, the Company's actual rate base was $6.4 billion. In addition, the NEB allows the Company to record an Allowance for Funds Used During Construction (AFUDC) which includes a return on common equity. AFUDC varies from year to year depending on the level of the construction program and the rate of return.

The NEB set the segment's rate of return on common equity at 12.25%, 13.25% and 13.50% for the years 1993, 1992 and 1991, respectively. The deemed common equity component in all three years was 30%. The approved rate of return on rate base was 10.95% for 1993, 11.56% for 1992 and 12.11% for 1991, reflecting year-over-year changes in the rate of return on common equity, noted above, and the reduced cost of financing arranged by the Company.

Canadian mainline system revenues in 1993 of $1,584.1 million increased by over 7%, or $109.2 million, over revenues for 1992. This increase reflects a 7.9% increase in total deliveries resulting from addition of facilities built to provide new service to customers. Eastern Canadian transportation tolls for 1993 increased 0.09% over those for 1992. Revenues for 1992 increased by approximately 21%, or $254.3 million, over those for 1991. This resulted from a 19% increase in total deliveries as well as higher tolls. The eastern Canadian delivery toll in 1992 increased by 2.84%, reflecting the cost of the additional capacity plus other cost increases. Export deliveries in 1993 increased from 1992 levels and represented 43% of total deliveries. Export deliveries in 1992 accounted for about the same percentage of total deliveries as in 1993. In 1991 almost 37% of total deliveries were exported.

Gas Marketing Segment

The Gas Marketing segment includes the financial results of the Western Gas Marketing subsidiaries. Approximately 90% of gas marketing revenues are generated from sales of natural gas (including marketing fees earned) under a netback agreement with Alberta producers and marketers. The netback agreement provides for the purchase of natural gas in Alberta and its subsequent sale in Canada and the United States. The marketing fees derived from netback sales are based on both volumes sold and prices obtained for natural gas. The principal risk to the Company with respect to netback sales is the level of its marketing fee in relation to its operating costs.

Other volumes of gas are purchased under short-term contracts with producers and marketers in Canada and the United States. In these transactions, the Company minimizes its market risk by matching the short-term obligations to purchase and sell natural gas. Various forms of financial instruments are used to assist in this management of risk.

Gas marketing revenues are dependent upon a number of factors including weather, pipeline operations, pipeline tariff structures and gas purchase costs. The following table shows volumes and revenues for sales made under the netback agreement and sales of all other purchases.

Volumes (billions of cubic feet)	**1993**	1992	1991
Canadian			
Netback	**576.5**	514.5	514.4
Other	**23.8**	67.5	47.0
	600.3	582.0	561.4
United States			
Netback	**491.3**	443.7	356.8
Other	**87.4**	165.2	87.6
	578.7	608.9	444.4
Total	**1,179.0**	1,190.9	1,005.8
Revenues (millions of dollars)			
Canadian			
Netback	**1,037.2**	855.3	980.9
Other	**67.6**	118.2	77.6
	1,104.8	973.5	1,058.5
United States			
Netback	**1,165.5**	857.6	587.1
Other	**280.5**	358.1	149.2
	1,446.0	1,215.7	736.3
Other revenues	**49.5**	41.6	40.4
Total	**2,600.3**	2,230.8	1,835.2

Total volumes sold during 1993 decreased from 1992 levels by 11.9 billion cubic feet (Bcf), or approximately 1%, however, netback volumes increased by 109.6 Bcf, or approximately 11.4%. Total revenues increased by $369.5 million, or approximately 16.6%, over 1992 levels, reflecting increased prices received for the higher netback volumes. This netback volume increase was partially offset by a decrease in other Canadian and United States sales in 1993. This decrease was the result of increased competition, particularly in the spot market. Prices in 1992 and consequently revenues were weaker in Canadian markets compared to 1991, but sales, of both netback and other gas to United States markets, and related prices increased.

Associated Operations and Other Segment

This segment includes the financial results from the Company's interests in associated pipelines and projects in Canada and the United States as well as administration and development activities. It also includes the results from the manufacturing and sale of thermal carbon black, the production and marketing of nitroparaffins, the extraction of natural gas liquids and ethane from natural gas and the generation of electrical power.

Income in 1993 from the Company's equity interests in associated operations was $149.4 million, 16% greater than in 1992. This increase includes results for a full year from the Company's investment in Alberta Natural Gas Company Ltd which was purchased at the end of June 1992 as well as the impact of a stronger U.S. dollar. Equity earnings for 1993 were also improved by the results of the Iroquois Gas Transmission System which commenced operations in November 1991, but was not fully operational until November 1992. Income in 1992 from the Company's equity investments in associated operations was $128.4 million, representing a 36% increase from 1991. This increase was due primarily to new facilities put into service on the Great Lakes System and completion of Phase II of the Ocean State Power Plant. Because these additional investments did not become operational until late 1991, the impact on income was not significant until 1992.

Strengthening of the U.S. dollar in relation to the Canadian dollar during 1992 also contributed to the increase. Project administration and development expenses increased in 1993 compared to previous years as a result of the increased activity in developing new projects. The contribution of the other elements of this segment is relatively minor.

Other Expense (Income)

Financial charges for 1993 increased by $20.8 million to $464.0 million compared to $443.2 million in 1992 which, in turn, increased by $42.4 million compared to those of 1991. These increases reflect the increases in long-term debt resulting from the Canadian mainline system expansion program over the last three years, offset to some extent by the retirement of debt.

AFUDC related to the expansion of the Canadian mainline system decreased from $42.8 million in 1992 to $18.1 million for the year ended December 31, 1993. The Company's expansion program peaked during 1992 when AFUDC was $9.9 million greater than in 1991.

Interest and other income reflects primarily earnings on invested cash. Interest and other income declined by $35.4 million in 1993 compared to 1992 as a result of the use of cash on deposit to repay long-term debt as well as lower interest rates. The decrease from 1991 to 1992 was due to a combination of lower average cash balances and lower average interest rates.

Income Taxes

Income taxes decreased by $44.5 million in 1993 compared to the previous year. In 1993, the NEB directed the Company to return to its tollpayers the previously collected deferred income tax expense related to the Canadian mainline system. This is being done over a three-year period and resulted in a reduction in income taxes of $25.3 million in 1993. The balance of the reduction is due primarily to reduced income taxes payable related to the Canadian mainline system. In 1992, income taxes increased by $32.7 million over 1991 due to a higher level of taxable income.

Liquidity and Capital Resources

In 1993, the Company generated $589.7 million of cash from operations and raised $439.7 million from new financings for a total of over $1 billion. These sources of cash, together with cash on hand, were used to fund 1993 capital expenditures and investment requirements, retire debt and pay dividends on preferred and common shares.

During 1993, the Company raised $72.9 million of common equity and $366.8 million of medium-term notes and debentures. In 1992, the Company issued a total of $1,682.5 million in debt, equity preferred shares, preferred shares and common shares.

In the fourth quarter of each of the last three years, the Company increased the dividend declared on common shares. In the fourth quarter of 1991, the dividend was raised from 18 cents to 19 cents per common share and, in the fourth quarters of each of 1992 and 1993, it was increased by two cents to 21 cents and 23 cents per common share, respectively.

Capital expenditures and investments for 1994 have been budgeted at approximately $587 million. These expenditures are for Canadian mainline facilities (approximately $460 million) and investments in projects and associated operations. To finance these requirements, the Company expects to use internally generated funds as well as external financing. At December 31, 1993, the Company had unused lines of credit of $600 million.

Environment

The Company is strongly committed to the protection of the environment. Central to this commitment is the need to ensure that all decisions affecting the environment are made with full consideration of current and potential future environmental effects. Company standards are designed to meet current government or community standards. Where there is a demonstrated benefit, having due regard to the economic and technical viability, the Company strives to exceed these standards. Reference should be made to Note 17 to the Company's consolidated financial statements for information on environmental matters related to the Company and certain of its associated operations.

Outlook

In July 1993, the Company filed an application with the NEB to establish tolls for the Canadian mainline system for 1994. Among other things, the application, as amended, requests approval of a 12.375% rate of return on a deemed common equity component of 30%. The hearing for this application commenced in February 1994 and a decision is expected by mid-1994. Pending the decision, interim tolls for 1994 were set by the NEB at 1993 levels. Based on past decisions, the NEB may set the allowed rate of return or deemed common equity level at a level below that which the Company has requested, however, the Company is unable to predict the ultimate outcome of the hearing. Based upon the forecasted average rate base for 1994 of approximately $6.4 billion, a 0.25% change in the rate of return on common equity would impact expected 1994 net income by approximately $5 million, or approximately 2.5 cents per share, and a change of 1% in the deemed common equity component would impact expected net income by approximately $6.3 million, or 3.2 cents per share. Further, the Company's current "A" credit rating could be adversely affected if the NEB were to reduce the deemed common equity component below 30%.

It has been the Company's practice to apply to the NEB for approval to expand its Canadian mainline system to meet projected aggregate requirements pursuant to transportation contracts with its existing shippers and precedent agreements with those prospective shippers that meet certain criteria. In general, the Company assesses and demonstrates to the NEB the economic feasibility of the expansion by determining the likelihood of demand charges being paid and the likelihood of the facilities being used at a reasonable level over their economic life. Factors such as long-term aggregate gas supply, long-term aggregate gas demand in market regions being served by the mainline, competition to gas supplies delivered by the Canadian mainline system and risks associated with any new sales are considered in this assessment. With respect to prospective new shippers, TransCanada obtains relevant information on related gas contracts including project-specific gas supply, upstream and downstream gas transportation contracts, regulatory approvals, financial integrity of parties to the gas sales contract and risks associated with the new contracts. In the case of prospective new shippers – where it is determined that additional facilities are required to meet projected aggregate requirements – the Company requires a minimum transportation contract term of 10 years.

As a result of the existing contract renewal policy, significant transportation service volumes are underpinned by short-term transportation contracts. Approximately 1.4 Bcf/day of existing firm transportation service volumes are supported by contracts that terminate prior to year-end 1995. The Company's tariff provides that shippers have the right to renew their transportation contracts, on an evergreen basis, with a notice period of six months provided the shipper meets certain conditions of the tariff. The minimum term of a transportation renewal contract is one year.

In light of increased competition and the relatively large portion of transportation service underpinned by short-term contracts, TransCanada has proposed in its current tolls application changes to its tariff regarding term and notice period for transportation contracts. The proposal involves providing a toll incentive for greater than six months' notice of renewal and for a remaining contract term longer than one year, thereby mitigating the risk to future tollpayers of increased tolls resulting from system underutilization.

TransCanada continues to hold a limited right of first refusal to acquire Pacific Gas and Electric Company's (PG&E) 100% interest in Pacific Gas Transmission Company. PG&E has successfully restructured the gas purchase contracts between its subsidiary Alberta and Southern Gas Co. Ltd. and Canadian gas producers, but remains involved in discussions with the California Public Utilities Commission over cost recoveries. The Company expects to reopen discussions with PG&E once all related issues have been resolved, which should occur sometime during 1994.

The Company expects further expansion of the Canadian mainline system to take place, however, at a much slower pace in the immediate future than has been the case over the last five years. The Company has been evaluating natural gas related projects with the goal of strengthening its asset base, diversifying its sources of income and obtaining returns on equity superior to the allowed rate of return from the Canadian mainline system. The Company bid on projects in South America but was unsuccessful. TransCanada was also involved in a project in Vietnam and is waiting for the Government of Vietnam to award the project. The year 1994 will undoubtedly bring more opportunities including the possibility of a partnership interest in a project in Tanzania consisting of a system of offshore and onshore pipelines and a 100-megawatt power generation plant. Closer to home, three proposed pipeline projects in the United States, in which the Company has an interest, are at various stages of development with in-service dates planned for 1995, 1996 and 1997, subject to various regulatory approvals.

Power generation projects continue to be an investment opportunity for the Company. Subject to provincial regulatory approvals, the Company has reached agreement in principle with Ontario Hydro to construct and operate two power generation plants at North Bay and Kapuskasing, Ontario. These plants are scaled down versions (40 megawatts each) of the plants that were cancelled due to the excess supply situation that Ontario Hydro announced in late 1992. The Company anticipates that construction will commence in 1995, with completion in 1996. A power generation project in Oregon, in which the Company is a partner, could commence construction between 1995 and 2000 subject to demand requirements of a federal power authority. In addition, the Company is investigating acquiring partnership interests in two potential power generation projects located in Québec.

The Company is also investigating natural gas storage facilities in Michigan and Alberta. These facilities could provide additional flexibility to service customers at peak demand times and are subject to regulatory and other approvals.

For further information on the various projects noted above, reference may be made to the headings "New Pipeline Projects – North America," "New Projects – International," "Power Generation" and "Complementary Businesses – Gas Storage" elsewhere in this Annual Report.

There is obviously a financial cost to all such undertakings. The Company has an extensive process for approval of projects and project costs. Expenditures are monitored carefully to ensure they are prudently incurred and until such time that Management judges that there is sufficient assurance that a project will proceed successfully, all costs are expensed. While over the short term this policy may reduce earnings, Management believes that its practices are appropriate given the pre-development status of these projects.

A rapid turnaround in producer upstream activity occurred in 1993 compared to the very low levels undertaken in 1992. Encouraged by provincial government royalty incentives to drill for oil and strengthening natural gas prices, producers responded by almost doubling oil well drilling completions and tripling gas well drilling completions. In 1993, Canadian local distribution companies agreed to pay prices based on the natural gas commodity prices quoted on the New York Mercantile Exchange or other benchmarks. These factors should encourage continued exploration and development activity. Stability in world oil markets, however, must be achieved for natural gas prices to be sustained at current levels. Falling world oil prices will put significant downward pressure on prices for natural gas in order for it to compete. Over the longer term, consistently low oil prices could have an adverse impact on natural gas supply as upstream activity would be curtailed.

TransCanada will continue to look for energy related opportunities at home and abroad to strengthen its returns to its stakeholders. Industry studies indicate that at present, a balance between supply and demand for natural gas in North America has been reached. In Management's opinion, the North American natural gas industry has benefitted from a deregulated marketplace, and these benefits should be maintained if market forces continue to develop freely.

Definitions

Rate Base

Is the sum of the cost, after accumulated depreciation, of the assets used by the Company in the transmission of natural gas, principally, gas plant in service, plus or minus the balance of certain deferred amounts.

Gas Plant in Service

Consists primarily of the pipe and compression facilities used in the transmission of natural gas.

Allowance for Funds Used During Construction

"AFUDC" is an allowance to compensate the Company for the cost of financing debt and equity funds used during construction of the Gas Transmission segment's rate base. This allowance is capitalized (added to the cost of the gas plant under construction). It is calculated using the allowed rate of return on rate base.

Rate of Return on Rate Base

This rate (as approved by the National Energy Board) is the blended cost of the Company's capital. When applied to the Gas Transmission segment's average rate base, it establishes the amount the Company will receive to pay the cost of its debt, preferred shares and to provide a return on common equity.

Rate of Return on Common Equity

Expressed as a percentage, this is the component of the rate of return on rate base which represents the return earned by the Gas Transmission segment on behalf of the Company's common shareholders.

Deemed Common Equity Component

Also referred to as the common equity ratio, this percentage is the amount of common equity that is approved by the National Energy Board as being dedicated to finance the Gas Transmission segment's rate base.

Year ended December 31
(stated in millions of dollars except per share amounts)

	1993	1992	1991
Operating Revenues	4,242.1	3,757.5	3,094.1
Income from Associated Operations (NOTE 4)	149.4	128.4	94.2
	4,391.5	3,885.9	3,188.3
Costs and Expenses	3,312.0	2,887.7	2,392.4
Depreciation	205.7	187.7	146.4
	3,517.7	3,075.4	2,538.8
Income before the Undernoted	873.8	810.5	649.5
Other Expense (Income)			
Financial charges (NOTE 7)	464.0	443.2	400.8
Allowance for funds used during construction	(18.1)	(42.8)	(32.9)
Interest and other income	(13.4)	(48.8)	(67.1)
	432.5	351.6	300.8
Income before Income Taxes	441.3	458.9	348.7
Income Taxes (NOTE 9)	85.7	130.2	97.5
Net Income for the Year	355.6	328.7	251.2
Net Income Per Share for the Year (NOTE 12)	$1.62	$1.56	$1.34

The accompanying notes to the consolidated financial statements are an integral part of these statements.

CONSOLIDATED CHANGES IN FINANCIAL POSITION

Year ended December 31
(stated in millions of dollars)

	1993	1992	1991
Cash Generated From Operations			
Net income for the year	**355.6**	328.7	251.2
Depreciation	**205.7**	187.7	146.4
Deferred income taxes	**(38.6)**	26.7	(29.7)
Income from associated operations less dividends received	**(56.1)**	(46.6)	(50.9)
Allowance for equity funds used during construction	**(7.3)**	(17.9)	(13.4)
Other	**18.2**	8.3	33.5
Funds generated from operations	**477.5**	486.9	337.1
Decrease/(increase) in operating working capital (NOTE 16)	**112.2**	(202.7)	168.1
	589.7	284.2	505.2
Investment Activities			
Capital expenditures	**(744.0)**	(1,324.3)	(1,417.0)
Associated operations			
Associated pipelines and projects	**(13.8)**	(6.6)	(108.3)
Ocean State Power Plant	**–**	–	(44.4)
Alberta Natural Gas Company Ltd	**–**	(146.9)	–
Return of capital from investments	**9.5**	15.6	–
Deferred amounts and other	**58.8**	11.8	93.2
	(689.5)	(1,450.4)	(1,476.5)
Dividends Paid	**(211.3)**	(184.9)	(145.6)
Financing Activities			
(Decrease)/increase in notes payable	**(99.8)**	164.1	–
Long-term debt issued	**366.8**	1,112.0	684.1
Reduction of long-term debt	**(577.8)**	(172.3)	(211.5)
Convertible debentures issued	**–**	–	149.8
Preferred shares issued	**–**	129.1	148.4
Preferred shares redeemed or repurchased	**(5.5)**	(80.7)	(0.3)
Equity preferred shares issued	**–**	197.0	–
Common shares issued	**72.9**	80.3	286.6
Other	**–**	–	(57.9)
	(243.4)	1,429.5	999.2
(Decrease)/Increase in Cash and Short-Term Investments	**(554.5)**	78.4	(117.7)
Cash and Short-Term Investments – at beginning of year	**598.9**	520.5	638.2
Cash and Short-Term Investments – at end of year	**44.4**	598.9	520.5

The accompanying notes to the consolidated financial statements are an integral part of these statements.

December 31
(stated in millions of dollars)

ASSETS	1993	1992
Current Assets		
Cash and short-term investments (NOTE 5)	**44.4**	598.9
Accounts receivable (NOTE 15)	**468.8**	514.3
Other	**52.7**	67.0
Total current assets	**565.9**	1,180.2
Associated Operations (NOTE 4)	**945.3**	879.5
Plant, Property and Equipment (NOTES 3 AND 6)	**6,544.3**	6,000.6
Deferred Amounts (NOTE 13)	**102.3**	176.3
	8,157.8	8,236.6

LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (NOTE 5)	**64.3**	164.1
Accounts payable (NOTE 15)	**450.1**	458.3
Income taxes payable	**50.1**	–
Interest accrued	**140.4**	157.7
Dividends payable	**57.0**	52.2
Long-term debt due within one year (NOTE 6)	**107.5**	577.4
Total current liabilities	**869.4**	1,409.7
Long-Term Debt (NOTE 6)	**4,170.0**	3,894.8
Deferred Income Taxes	**71.3**	95.6
Convertible Debentures (NOTE 8)	**150.0**	150.0
Preferred Shares (redeemable) (NOTE 10)	**582.8**	588.3
Equity Preferred Shares and Common Shareholders' Equity		
Equity preferred shares (NOTE 11)	**197.0**	197.0
Common shares (NOTE 12)	**863.9**	791.0
Contributed surplus	**266.8**	269.6
Retained earnings	**965.2**	825.7
Foreign exchange adjustment	**21.4**	14.9
	2,314.3	2,098.2
Commitments and Contingencies (NOTE 17)		
	8,157.8	8,236.6

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

G.W. Maier
Director

H.C. Schaefer
Director

CONSOLIDATED CONTRIBUTED SURPLUS AND RETAINED EARNINGS

Year ended December 31
(stated in millions of dollars except per share amounts)

CONTRIBUTED SURPLUS	1993	1992	1991
Balance at beginning of year	**269.6**	269.6	271.6
Share issue expenses	**(2.8)**	–	(2.0)
Balance at end of year	**266.8**	269.6	269.6

RETAINED EARNINGS	1993	1992	1991
Balance at beginning of year	**825.7**	692.1	594.5
Net income for the year	**355.6**	328.7	251.2
	1,181.3	1,020.8	845.7
Dividends declared			
Preferred (redeemable) (NOTE 10)	**46.6**	48.5	31.8
Equity preferred and common	**169.5**	146.6	121.8
	216.1	195.1	153.6
Balance at end of year	**965.2**	825.7	692.1
Dividends per common share	**$0.86**	$0.78	$0.73

The accompanying notes to the consolidated financial statements are an integral part of these statements.

AUDITORS' REPORT

KPMG Peat Marwick Thorne

To the Shareholders of TransCanada PipeLines Limited

We have audited the consolidated statements of financial position of TransCanada PipeLines Limited as at December 31, 1993 and December 31, 1992 and the consolidated statements of income, contributed surplus and retained earnings and changes in financial position for each of the years in the three-year period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1993 and December 31, 1992 and the results of its operations and the changes in its financial position for each of the years in the three-year period ended December 31, 1993 in accordance with Canadian generally accepted accounting principles.

KPMG Peat Marwick Thorne

Chartered Accountants
Calgary, Canada
January 20, 1994

NOTE 1 ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with accounting principles generally accepted in Canada (Canadian GAAP). These accounting principles are different in some respects from those generally accepted in the United States (U.S. GAAP) and the significant differences are described in Note 18. Amounts are stated in Canadian dollars unless otherwise indicated. The significant accounting policies of the Company are summarized below:

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada PipeLines Limited and its subsidiaries (the Company or TransCanada). The Company uses the equity method of accounting for investments in which it exercises significant influence. Other investments and projects which are in the development stage are included at cost in Deferred Amounts. Costs related to investments and projects which are in the pre-development stage are expensed.

Regulation

The Company is subject to the authority of the National Energy Board (NEB) with respect to the determination of tolls and related accounting for the natural gas transmission system (the Gas Transmission segment). In order to achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in this segment may differ from that otherwise expected under generally accepted accounting principles applicable to non-regulated businesses. The companies and partnerships in which the Company has investments are also subject to the authority of certain regulatory bodies.

Cash and Short-Term Investments

The Company's short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

Plant, Property and Equipment

Gas Transmission

Gas transmission plant is carried at cost. Depreciation is calculated on a straight-line basis using rates approved by the NEB. During 1993, pipelines were depreciated at 2.44% (1992 and 1991 - 2.50%), compressor equipment at 3.02% (1992 and 1991 - 3.50%) and other fixed assets at various rates. Removal and site restoration costs are provided for when reasonably determinable and as approved by the NEB. An allowance for funds used during construction is capitalized and included in the cost of gas transmission plant. The rate employed in calculating this allowance is the rate of return on rate base approved by the NEB.

Gas Marketing and Other Plant

Plant, property and equipment is carried at cost and depreciated on a straight-line basis over estimated service lives. Interest is capitalized on projects under construction.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Certain debt denominated in U.S. dollars is a partial hedge of the Company's net investment in U.S. dollars. The resulting translation adjustments are reflected in a separate component of shareholders' equity. Foreign exchange gains and losses on Gas Transmission segment related debt are included in income as they are dealt with in the tollmaking process.

Income Taxes

The Company follows the taxes payable method of accounting for income taxes related to the operations of the Gas Transmission segment. This method is prescribed by the NEB for tollmaking purposes. Since there is reasonable expectation that all such taxes will be included in future costs of service and recovered in revenues at such time, this method is being followed for accounting purposes. The Company follows the deferral method of tax allocation accounting for other operations.

Post-Employment Benefits Other Than Pensions

The Company provides its retired employees with life insurance and certain medical benefits beyond those provided by government sponsored plans. The cost of these benefits is expensed when paid.

Comparative Figures

Certain comparative figures have been reclassified to conform with the current financial statement presentation.

NOTE 2 SEGMENTED AND OTHER INFORMATION

The Company operates in three business segments:

(i) ***Gas Transmission***

The Company owns and operates a natural gas transmission system which extends from Alberta into Québec. The gas transmission system transports natural gas to regional natural gas distribution and transmission companies in Canada and the United States.

Matters such as tolls, construction, operations and accounting in connection with the gas transmission system are subject to the authority of the NEB. Tolls are determined by the NEB on a rate base, rate of return and cost of service basis. Due to the regulatory deferral process, variations in the Gas Transmission segment's revenues and volumes by themselves do not have an impact on net income.

(ii) ***Gas Marketing***

The Company's gas marketing operations, carried on by the Western Gas Marketing subsidiaries (Western Gas), are included in this segment. Western Gas, as agent for TransCanada, administers the purchase of natural gas acquired under a netback pricing arrangement with Alberta producers and the subsequent sale of this natural gas. Western Gas also purchases and sells natural gas on its own behalf and provides transportation and storage services. These other purchases and sales are generally short-term contracts and Western Gas minimizes its risk by matching obligations to purchase and sell natural gas. Various forms of financial instruments are used to assist in this management of risk. Principal customers for Western Gas' sales and services are natural gas distribution companies and industrial users in Canada and the United States.

(iii) ***Associated Operations and Other***

This segment includes the Company's interests in associated pipelines and projects in Canada and the United States, as well as administration and development activities. It also includes the manufacturing and sale of thermal carbon black, the production and marketing of nitroparaffins, the extraction of natural gas liquids and ethane from natural gas and the generation of electrical power.

(a) Business Segments

The Company's financial data by business segment is as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Operations by business segment			
Gas Transmission			
Operating revenues			
Domestic deliveries	**883.0**	877.2	826.5
Export deliveries (customers serving United States markets)	**689.8**	586.1	390.0
Other revenues	**11.3**	11.6	4.1
	1,584.1	1,474.9	1,220.6
Operating costs	**658.1**	626.8	541.7
Depreciation	**195.0**	177.3	138.8
	853.1	804.1	680.5
	731.0	670.8	540.1
Gas Marketing			
Operating revenues			
Canadian sales	**1,104.8**	973.5	1,058.5
United States sales	**1,446.0**	1,215.7	736.3
Other revenues	**49.5**	41.6	40.4
	2,600.3	2,230.8	1,835.2
Cost of gas	**2,548.2**	2,182.7	1,779.4
Operating costs	**39.1**	35.9	35.5
Depreciation	**1.8**	2.0	1.2
	2,589.1	2,220.6	1,816.1
	11.2	10.2	19.1
Associated Operations and Other			
Associated operations – equity income			
Canadian	**27.9**	20.5	16.6
United States	**121.5**	107.9	77.6
	149.4	128.4	94.2
Other operating revenues			
Canadian	**37.8**	31.6	20.9
United States and international	**19.9**	20.2	17.4
	207.1	180.2	132.5
Operating costs	**30.9**	26.1	19.1
Project administration and development expenses	**35.7**	16.2	16.7
Depreciation	**8.9**	8.4	6.4
	75.5	50.7	42.2
	131.6	129.5	90.3

Year ended December 31 (millions of dollars)	1993	1992	1991
Capital expenditures and investments			
Gas Transmission	**748.3**	1,328.2	1,393.6
Less allowance for equity funds used during construction	**7.3**	17.9	13.4
	741.0	1,310.3	1,380.2
Gas Marketing	**1.3**	1.9	1.1
Associated Operations and Other	**6.0**	150.0	188.4
	748.3	1,462.2	1,569.7
Business segment assets			
Gas Transmission – Canadian	**6,615.7**	6,126.5	4,941.7
Gas Marketing			
Canadian (primarily accounts receivable)	**335.5**	342.1	271.4
United States (primarily accounts receivable)	**64.7**	118.9	69.0
	400.2	461.0	340.4
Associated Operations and Other			
Canadian	**334.6**	313.1	188.6
United States	**737.9**	668.8	583.9
	1,072.5	981.9	772.5
	8,088.4	7,569.4	6,054.6
Corporate Assets	**69.4**	667.2	550.1
	8,157.8	8,236.6	6,604.7

(b) Principal Customers

The following table sets forth the Company's revenues generated from the sale and transmission of natural gas to its five principal customers:

Year ended December 31 (millions of dollars)	1993	1992	1991
The Consumers' Gas Company Ltd.	**488.1**	503.9	487.6
Alberta Northeast Gas, Limited	**336.8**	200.0	1.0
Gaz Métropolitain, inc.	**273.0**	256.3	272.7
The Coastal Corporation	**216.2**	109.2	71.8
Centra Gas Ontario Inc.	**194.5**	208.7	199.2

NOTE 3 PLANT, PROPERTY AND EQUIPMENT

	1993			1992
December 31 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Gas Transmission				
Gas plant in service				
Mainline	6,429.8	1,345.4	5,084.4	4,499.8
Compression	1,536.0	389.4	1,146.6	1,072.4
Metering and other	222.3	61.8	160.5	143.7
	8,188.1	1,796.6	6,391.5	5,715.9
Gas plant under construction	39.0	–	39.0	160.2
	8,227.1	1,796.6	6,430.5	5,876.1
Gas Marketing	11.8	5.8	6.0	7.1
Other Plant	173.3	65.5	107.8	117.4
	8,412.2	1,867.9	6,544.3	6,000.6

NOTE 4 ASSOCIATED OPERATIONS

The Company's equity investments and its share of the earnings from these associated operations for the years ended are as follows:

	1993		1992		1991	
(millions of dollars)	Equity Investment	Earnings	Equity Investment	Earnings	Equity Investment	Earnings
Associated Pipelines						
Great Lakes System	325.2	58.4	261.9	54.1	234.8	30.5
Northern Border Pipeline Company	232.3	29.2	229.0	24.7	191.7	22.9
Foothills Pipe Lines (Sask.) Ltd.	29.7	5.2	23.4	6.4	27.4	8.7
Trans Québec & Maritimes Pipeline	37.9	10.2	39.4	11.3	40.7	7.9
Iroquois System	62.8	12.5	69.2	5.9	51.0	9.8
Ocean State Power Plant	107.8	21.4	108.7	23.2	106.4	14.4
Alberta Natural Gas Company Ltd	149.6	12.5	147.9	2.8	–	–
	945.3	149.4	879.5	128.4	652.0	94.2

Dividends and distributions received from associated operations amounted to $93.3 million, $81.8 million and $43.3 million for the years ended December 31, 1993, 1992 and 1991, respectively. Consolidated retained earnings at December 31, 1993, includes $242.0 million (December 31, 1992 - $188.9 million), which represents undistributed earnings from these associated operations.

ASSOCIATED PIPELINES

Great Lakes System

The Company owns 50% of Great Lakes Gas Transmission Company, which operates a pipeline system (Great Lakes System) extending from the Canada/United States border near Emerson, Manitoba through the United States to the vicinity of Sarnia, Ontario.

The following sets out summarized financial information for the Great Lakes System:

December 31 (millions of US dollars)	1993	1992
Natural gas transmission plant (net)	**1,055.3**	999.2
Current assets	**84.7**	79.2
Current liabilities	**(49.8)**	(79.4)
Deferred credits	**(16.9)**	(17.1)
Long-term debt	**(500.0)**	(500.0)
Equity	**573.3**	481.9

Year ended December 31 (millions of US dollars)	1993	1992	1991
Operating revenues	**246.5**	244.1	185.6
Operating expenses	**(113.9)**	(110.9)	(112.6)
Interest (net)	**(42.4)**	(45.7)	(17.7)
Net income	**90.2**	87.5	55.3

Northern Border Pipeline Company

The Company owns a 30% interest in Northern Border Pipeline Company, a partnership which owns a natural gas pipeline extending from the Canada/United States border near Monchy, Saskatchewan to a point near Harper, Iowa.

The following sets out summarized financial information for Northern Border Pipeline Company:

December 31 (millions of US dollars)	1993	1992
Natural gas transmission plant (net)	**1,051.5**	1,087.3
Current assets	**36.3**	38.0
Deferred charges	**21.6**	36.2
Current liabilities	**(42.4)**	(58.7)
Deferred credits	**(3.3)**	–
Long-term debt	**(457.0)**	(467.5)
Equity	**606.7**	635.3

Year ended December 31 (millions of US dollars)	1993	1992	1991
Operating revenues	**205.2**	167.6	156.2
Operating expenses	**(86.8)**	(70.9)	(59.7)
Interest (net)	**(43.2)**	(28.2)	(29.6)
Net income	**75.2**	68.5	66.9

Foothills Pipe Lines (Sask.) Ltd.

The Company is the operator and owns 44% of Foothills Pipe Lines (Sask.) Ltd. (Foothills (Sask.)), which owns a pipeline extending from the Alberta/Saskatchewan border near Empress, Alberta to the Canada/United States border near Monchy, Saskatchewan where it connects with the Northern Border pipeline.

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

December 31 (millions of dollars)	1993	1992
Natural gas transmission plant (net)	**279.4**	280.3
Current assets	**9.8**	13.4
Current liabilities	**(0.1)**	(3.1)
Deferred credits	**(70.4)**	(70.3)
Long-term debt	**(143.9)**	(160.5)
Equity	**74.8**	59.8

Year ended December 31 (millions of dollars)	1993	1992	1991
Operating revenues	**42.8**	46.6	56.4
Operating expenses	**(19.2)**	(19.9)	(20.4)
Interest (net)	**(11.6)**	(12.6)	(16.4)
Net income	**12.0**	14.1	19.6

Trans Québec & Maritimes Pipeline

The Company owns a 50% interest in TQM Pipeline Partnership (TQM), a partnership which owns a pipeline system in the province of Québec extending from Saint-Lazare, near Montréal, to a point just west of Québec City. The pipeline system is operated by Trans Québec & Maritimes Pipeline Inc., in which the Company has a 50% interest.

The following sets out summarized financial information for TQM:

December 31 (millions of dollars)	1993	1992
Natural gas transmission plant (net)	**332.6**	345.1
Current assets	**8.0**	7.9
Deferred charges	**0.8**	1.5
Current liabilities	**(185.1)**	(16.0)
Long-term debt	**(72.0)**	(250.5)
Equity	**84.3**	88.0

Year ended December 31 (millions of dollars)	1993	1992	1991
Operating revenues	**72.0**	76.7	74.5
Operating expenses	**(22.7)**	(23.1)	(22.8)
Interest (net)	**(29.6)**	(33.3)	(34.9)
Net income	**19.7**	20.3	16.8

Iroquois System

The Company has a 29% interest in Iroquois Gas Transmission System L.P., which owns a pipeline system (Iroquois System) extending from Iroquois, Ontario, across the St. Lawrence River, through the states of New York and Connecticut to Long Island, New York. The Iroquois System was constructed during 1991 and commenced operation on December 1, 1991.

The following sets out summarized financial information for the Iroquois System:

December 31 (millions of US dollars)	1993	1992
Natural gas transmission plant (net)	**649.7**	651.1
Current assets	**41.1**	82.9
Deferred charges	**21.5**	4.6
Current liabilities	**(57.2)**	(28.0)
Long-term debt	**(473.8)**	(522.6)
Equity	**181.3**	188.0

Year ended December 31 (millions of US dollars)	1993	1992	1991
Operating revenues	**137.7**	91.8	1.7
Operating expenses	**(64.2)**	(45.9)	(2.7)
Allowance for funds used during construction	**1.4**	1.7	37.4
Interest (net)	**(42.9)**	(28.8)	(8.4)
Net income	**32.0**	18.8	28.0

OCEAN STATE POWER PLANT

The Company has a 40% equity interest in the partnership which owns the Ocean State Power combined-cycle power generation plant (Ocean State Power Plant) located in Rhode Island.

The following sets out summarized financial information for the Ocean State Power Plant:

December 31 (millions of US dollars)	1993	1992
Plant, property and equipment (net)	**352.8**	372.5
Current assets	**48.2**	48.5
Deferred charges	**11.6**	13.3
Current liabilities	**(25.5)**	(25.8)
Deferred credits	**(11.6)**	(8.6)
Long-term debt	**(182.0)**	(193.1)
Equity	**193.5**	206.8

Year ended December 31 (millions of US dollars)	1993	1992	1991
Operating revenues	**207.4**	215.6	130.9
Operating expenses	**(151.2)**	(154.7)	(89.9)
Interest (net)	**(14.8)**	(12.3)	(10.6)
Net income	**41.4**	48.6	30.4

ALBERTA NATURAL GAS COMPANY LTD

On June 30, 1992, the Company purchased an interest in the common shares of Alberta Natural Gas Company Ltd (ANG) from Pacific Gas Transmission Company. At December 31, 1993, the Company held 49.92% of ANG's common shares. ANG operates a pipeline which extends from the Alberta/British Columbia border through southeastern British Columbia, to the Canada/United States border near Kingsgate, British Columbia. ANG also produces and markets nitroparaffins and their derivatives and operates a natural gas liquids and ethane extraction plant.

The quoted market value of the Company's investment in ANG's common shares was approximately $211 million at December 31, 1993 (December 31, 1992 - $201 million).

The following sets out summarized financial information for ANG:

December 31 (millions of dollars)	**1993**	1992
Plant, property and equipment (net)	**376.5**	289.0
Current assets	**191.2**	168.9
Deferred charges and other	**72.9**	44.6
Current liabilities	**(197.8)**	(159.3)
Deferred credits	**(58.3)**	(49.9)
Long-term debt	**(176.7)**	(122.6)
Equity	**207.8**	170.7

(millions of dollars)	**Year ended December 31, 1993**	Six Months ended December 31, 1992
Operating revenues	**662.7**	268.6
Operating expenses	**(598.0)**	(243.7)
Interest (net)	**(16.4)**	(9.5)
Other	**13.7**	1.5
Income before income taxes	**62.0**	16.9
Income taxes	**(28.6)**	(7.4)
Net income	**33.4**	9.5

NOTE 5 FINANCIAL INSTRUMENTS AND NATURAL GAS TRADING

The Company utilizes various financial instruments to reduce its exposure to fluctuations in interest rates, currency rates and natural gas prices. The Company's credit risk with respect to these instruments is the possibility that a counterparty to a transaction fails to perform according to the terms of the contract. This credit risk is minimized by dealing only with highly rated domestic and international financial institutions. At December 31, 1993, the credit risk amounted to $24.2 million with respect to swaps and forward rate agreements and $1.0 million with respect to natural gas trading activities. The largest exposure to a single institution, at December 31, 1993, was $7.9 million.

At December 31, 1993, the Company had net assets denominated in United States dollars of approximately US$393.6 million (December 31, 1992 – US$482.4 million). The Company had entered into foreign exchange contracts totaling US$75.0 million and cross-currency swaps totaling US$200.0 million which partially hedged its exposure to the effect of changes in the United States/Canadian dollar exchange rate. These cross-currency swaps include a floating interest component which the Company has partially hedged for certain periods by entering into interest rate swaps of $62.5 million and US$200.0 million and two forward rate agreements of $125.0 million. Any premiums with respect to these instruments are deferred and amortized to income over the terms of the contracts.

Netback transactions represent approximately 90% of the natural gas volumes handled by the Company. The principal risk with respect to netback sales is the level of its marketing fee in relation to its operating costs.

Other purchases and sales are generally short-term contracts for which the Company minimizes its risk by matching obligations to purchase and sell natural gas. Various forms of financial instruments are used to assist in this management of risk. At December 31, 1993, the Company had entered into contracts to purchase and sell natural gas and had also entered into certain market related instruments to minimize the risk associated with its net position relative to these contracts. At December 31, 1993, notional contracts amounting to $15.1 million were outstanding.

The following summarizes the Company's position with respect to cash and short-term investments and notes payable as at December 31, 1993 and 1992:

(a) Cash and Short-Term Investments

	Balance at End of Year (millions of dollars)	Weighted Average Rate Per Annum End of Year	Average Amount Outstanding During the Year (millions of dollars)	Weighted Average Rate Per Annum During the Year
1993				
Term deposits				
in Canadian dollar accounts	**7.0**	**4.4%**	**125.6**	**5.4%**
in U.S. dollar accounts	**37.4**	**3.2%**	**120.6**	**3.2%**
Other	**–**	**–**	**30.4**	**4.3%**
	44.4			
1992				
Term deposits				
in Canadian dollar accounts	350.1	6.9%	367.1	6.6%
in U.S. dollar accounts	219.7	5.7%	222.6	3.9%
Other	29.1	4.8%	36.1	5.1%
	598.9			

The Company had no forward rate agreements at December 31, 1993, with respect to interest rate risk management of the cash and short-term investments included in the above table. At December 31, 1992, the Company had forward rate agreements with notional principal amounts totaling approximately $75.0 million.

(b) Notes Payable

	Balance at End of Year (millions of dollars)	Weighted Average Rate Per Annum End of Year	Average Amount Outstanding During the Year (millions of dollars)	Weighted Average Rate Per Annum During the Year
1993				
Bank loans	**–**	**–**	**39.0**	**7.2%**
Commercial paper	**64.3**	**4.0%**	**203.1**	**4.8%**
	64.3			
1992				
Bank loans	154.2	8.1%	34.4	7.7%
Commercial paper	9.9	8.5%	173.0	6.8%
	164.1			

The Company swapped interest obligations with notional principal amounts totaling approximately $51.2 million at December 31, 1993 (December 31, 1992 - $Nil).

The Company had unused lines of credit of $600.0 million at December 31, 1993 (December 31, 1992 - $611.9 million), for the purpose of supporting the Company's commercial paper program and for general corporate needs. These borrowing arrangements are available to the Company at prime rates of Canadian chartered banks and on other negotiated financial bases. The cost to maintain the unused portion of the lines of credit was approximately $0.7 million for the year ended December 31, 1993 (December 31, 1992 - $1.0 million).

NOTE 6 LONG-TERM DEBT

	Maturity Dates	1993 Outstanding December 31 (1)	1993 Average Interest Rate (2)	1992 Outstanding December 31 (1)	1992 Average Interest Rate (2)
Gas Transmission Segment					
First Mortgage Pipe Line Bonds					
Denominated in Canadian dollars		–	–	3.6	8.9%
Denominated in United States dollars					
(1993 - US$252.7; 1992 - US$282.1)	1996 and 1997	**334.6**	**16.2%**	358.6	16.2%
Denominated in Pounds Sterling					
(1993 - £25.0; 1992 - £25.0)	2007	**48.9**	**16.5%**	48.0	16.5%
Debentures					
Denominated in Canadian dollars	1996 to 2020	**1,779.8**	**10.9%**	1,629.8	11.0%
Denominated in United States dollars					
(1993 - US$800.0; 1992 - US$800.0)	2012 to 2023	**1,059.2**	**9.2%**	1,017.0	9.2%
Notes					
Denominated in Canadian dollars	1995 to 2003	**726.3**	**8.6%**	507.1	9.2%
Denominated in New Zealand dollars					
(1993 - NZ$Nil; 1992 - NZ$125.0)		–	–	104.1	14.3%
		3,948.8		3,668.2	
Foreign exchange differential recoverable through the tollmaking process		**(124.5)**		(90.5)	
Total		**3,824.3**		3,577.7	
Other					
Debentures					
Denominated in Canadian dollars		–	–	100.0	11.7%
Subordinated Debentures					
Denominated in United States dollars					
(1993 - US$200.0; 1992 - US$200.0)	2006	**264.8**	**9.1%**	254.2	9.1%
Notes					
Denominated in Canadian dollars	1997 and 2002	**24.8**	**8.5%**	24.8	8.5%
Denominated in Swiss francs					
(1993 - SFr.207.5; 1992 - SFr.521.2) (3)	1994 and 1995	**163.6**	**8.6%**	399.3	7.9%
Denominated in New Zealand dollars					
(1993 - NZ$Nil; 1992 - NZ$175.0)		–	–	116.2	14.1%
Total		**453.2**		894.5	
Total Long-Term Debt		**4,277.5**		4,472.2	
Less: Due Within One Year		**107.5**		577.4	
		4,170.0		3,894.8	

(1) Amounts outstanding are stated in millions of Canadian dollars; amounts denominated in currencies other than Canadian dollars are stated in millions.

(2) Current weighted average interest rates are stated as at the respective outstanding dates and include, where applicable, effective interest rates resulting from swap agreements.

(3) As at December 31, 1993, 207.5 million Swiss francs have been exchanged through swap agreements into Cdn.$163.6 million (December 31, 1992 - 417.2 million Swiss francs into Cdn.$335.7 million and 104.0 million Swiss francs into US$50.0 million).

First Mortgage Pipe Line Bonds

The Deed of Trust and Mortgage securing the Company's First Mortgage Pipe Line Bonds was amended in 1993 to limit the specific and floating charges on the Company's assets to those assets comprising the present and future Canadian mainline pipeline system and the present and future gas transportation contracts. No further bonds may be issued under the Deed of Trust and Mortgage. The bonds denominated in United States dollars are subject to mandatory sinking fund provisions which require the Company to retire prescribed amounts of each series annually prior to maturity.

Debentures and Subordinated Debentures

During 1993 and 1992, the Company issued debentures and subordinated debentures, the terms of which are as follows:

Issue	Principal Amount (millions of dollars)	Maturity Date	Interest Rate
1993	**$150**	**March 20, 2018**	**9.450% paid semi-annually**
1992	US$200	May 15, 2012	8.625% paid semi-annually
	US$200	March 20, 2023	8.500% paid semi-annually
	$100	December 20, 2017	9.800% paid semi-annually

In December 1992, the Company filed a shelf prospectus in Canada with a term of two years for the offering of up to $500 million of debentures. To December 31, 1993, $150 million of debentures had been issued under this shelf prospectus.

Notes

In 1993, the Company continued its Canadian Medium-Term Note Program by filing a shelf prospectus that allows for the issuance of notes with a wide range of maturities at varying interest rates. Also in 1993, the Company established an Indenture for the benefit of all Canadian Medium-Term Note holders. At December 31, 1993, $541.3 million was available to be issued under this Program. In addition, the Company may issue up to US$500 million of Medium-Term Notes under a shelf registration statement filed in the United States. The United States Medium-Term Notes will be issued as additional series under two existing Indentures.

Mandatory Retirements

In addition to purchase fund requirements which are applicable in certain circumstances, mandatory retirements of all long-term debt of the Company, as a result of maturities and sinking fund obligations, approximate: 1994 - $107.5 million; 1995 - $186.0 million; 1996 - $322.9 million; 1997 - $256.7 million; and 1998 - $82.9 million.

NOTE 7 FINANCIAL CHARGES

Year ended December 31 (millions of dollars)	1993	1992	1991
Interest on long-term debt	**466.3**	446.6	403.8
Amortization of foreign exchange contract premiums	**(7.6)**	(17.2)	(15.5)
Interest on long-term debt (net)	**458.7**	429.4	388.3
Regulatory deferrals and amortizations	**(5.8)**	(12.9)	(4.3)
Non-regulatory foreign exchange (gains)/losses	**(0.9)**	14.6	17.6
Short-term interest and other financial charges	**12.0**	13.4	1.8
Interest capitalized	–	(1.3)	(2.6)
	5.3	13.8	12.5
	464.0	443.2	400.8

The Company made interest payments of $496.3 million, $448.7 million and $399.0 million for the years ended December 31, 1993, 1992 and 1991, respectively.

NOTE 8 CONVERTIBLE DEBENTURES

On December 20, 1991, the Company issued $150 million of ten-year convertible subordinated debentures at an interest rate of 10.426%. The debentures are convertible, at the holder's option, into common shares at a price of $23.041 and are redeemable by the Company, under certain circumstances, after June 20, 1995. The Company may elect to pay interest when due, and principal on redemption or at maturity, in common or preferred shares of the Company subject to the debenture holder's right to receive a cash payment.

NOTE 9 INCOME TAXES

(a) The geographic components of income before income taxes are summarized below:

Year ended December 31 (millions of dollars)	1993	1992	1991
Canada	**332.4**	335.1	260.7
Foreign	**108.9**	123.8	88.0
	441.3	458.9	348.7

(b) The provision for income taxes is summarized as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Current			
Canada	**111.3**	93.7	120.9
Foreign	**13.0**	9.8	6.3
	124.3	103.5	127.2
Deferred			
Canada	**(51.7)**	12.7	(36.6)
Foreign	**13.1**	14.0	6.9
	(38.6)	26.7	(29.7)
	85.7	130.2	97.5

(c) Deferred income taxes result from timing differences in the recognition of revenue and expense for tax and financial statement purposes. The sources of these differences and their effect on income taxes are as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Capital cost allowance in excess of depreciation	**9.6**	7.7	3.9
Deferred amounts	**(23.1)**	10.9	(34.5)
Amortization of Gas Transmission segment deferred income taxes (f)	**(25.3)**	–	–
Other	**0.2**	8.1	0.9
	(38.6)	26.7	(29.7)

(d) Income tax expense differs from the amount computed by applying the basic Canadian federal income tax rate to income before income taxes. The reasons for these differences are as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Income before income taxes	**441.3**	458.9	348.7
Less income not subject to tax currently (f)	**(168.2)**	(118.5)	(106.2)
	273.1	340.4	242.5
Federal statutory tax rate	**38.8%**	38.8%	38.8%
Expected income tax expense	**106.0**	132.1	94.1
Amortization of Gas Transmission segment deferred income taxes (f)	**(25.3)**	–	–
Non-deductible capital losses	**5.4**	4.9	7.7
Net difference between the federal statutory tax rate and rates of provincial, state and foreign authorities	**(0.8)**	(8.6)	(1.6)
Utilization of prior years' operating losses	**(13.7)**	(11.7)	(10.6)
Large corporations tax	**13.8**	12.4	10.3
Other	**0.3**	1.1	(2.4)
Actual income tax expense	**85.7**	130.2	97.5

(e) At December 31, 1993, the Company's United States subsidiaries had net operating losses carried forward for accounting purposes of approximately US$53.9 million for which the future tax benefits have not been recorded. The net operating losses carried forward for tax purposes of US$177.0 million differ from the accounting losses primarily because of timing differences as described in (c) above. The accumulated tax losses can be carried forward and, subject to certain limitations, applied to reduce future taxable income of these subsidiaries. To the extent not used, these tax losses expire as follows: 2000 - US$63.2 million; 2001 - US$63.7 million; 2002 - US$37.5 million; and 2005 - US$12.6 million.

(f) During the period from August 1978 to July 1982, the Company was directed by the NEB to follow the deferral method of tax allocation accounting for income taxes. As a result, the Company recovered deferred income tax expense of approximately $76 million in tolls. In setting the Company's tolls for 1993, the NEB directed that the Company commence amortization of this amount over a three-year period and reduce its revenue requirement accordingly.

Prior to 1978 and subsequent to 1982, the Company was directed by the NEB to follow the taxes payable method of accounting for those income taxes related to the operations of the Gas Transmission segment. Had the deferral method of tax allocation accounting been prescribed by the NEB for this segment from the date of commencement of operations, additional deferred income taxes in the amount of $615.3 million to December 31, 1993 (December 31, 1992 - $562.0 million), would have been recorded and recovered in tolls to date through the tollmaking process.

(g) The Company made income tax payments of $66.4 million, $162.4 million and $26.1 million during the years ended December 31, 1993, 1992 and 1991, respectively.

NOTE 10 PREFERRED SHARES

The authorized number of preferred shares issuable in series is unlimited. Details of the Company's cumulative redeemable first preferred shares, all of which are without par value, are:

Year ended December 31 (millions of dollars)	1993	1992	1991
First Preferred Shares (1)			
Cumulative redeemable shares			
$2.80 Series (1993 - 555,868; 1992 - 557,168; 1991 - 569,768)	**27.8**	27.9	28.5
Series O (1993, 1992 and 1991 - 3,000,000)	**150.0**	150.0	150.0
Series P (1993 and 1992 - 2,600,000; 1991 - Nil)	**130.0**	130.0	–
Cumulative redeemable retractable shares			
Series H (1993 - Nil; 1992 - 39,791; 1991 - 39,991)	–	2.0	2.0
Series I (1993 - Nil; 1992 - 68,820; 1991 - 70,920)	–	3.4	3.5
Series J (1993 and 1992 - Nil; 1991 - 1,600,000)	–	–	80.0
Series N (1993, 1992 and 1991 - 1,500,000)	**75.0**	75.0	75.0
Cumulative redeemable perpetual shares			
Series K (1993, 1992 and 1991 - 150)	**75.0**	75.0	75.0
Series L (1993, 1992 and 1991 - 100)	**50.0**	50.0	50.0
Series M (1993, 1992 and 1991 - 150)	**75.0**	75.0	75.0
	582.8	588.3	539.0

(1) During 1993, 1992 and 1991, 1,300, 14,900 and 5,300 shares, respectively, were purchased by the Company for cancellation. The outstanding balances of the Cumulative Redeemable Retractable First Preferred Shares, Series H and I, were redeemed in 1993 and Series J was redeemed in 1992.

Additional information pertaining to the Company's preferred shares outstanding as at December 31, 1993, is as follows:

First Preferred Share Issue	Stated Value Per Share	Dividend Rate Per Share	Redemption Dates and Prices
$2.80 Series	$50	$2.80	redeemable any time, at $50.50 per share
Series O	$50	$3.95	redeemable after October 31, 1998, at $52 per share to October 31, 1999, reducing to $50 after October 31, 2001
Series P	$50	$3.875	redeemable after April 30, 1999, at $52 per share to April 30, 2000, reducing to $50 after April 30, 2002
Series N	$50	$4.50	retractable February 1, 1996, and redeemable after January 31, 1996, at the stated value per share
Series K	$500,000	$38,400	redeemable after October 31,1994, at the stated value per share
Series L	$500,000	$40,625	redeemable after December 1, 1995, at the stated value per share
Series M	$500,000	$42,750	redeemable after April 30, 1996, at the stated value per share

After October 31, 1998, the Company may elect to convert the Series O shares into common shares at 95% of the then market price of the common shares or, with the agreement of Series O shareholders, into a new issue of preferred shares. In addition, after October 31, 2001, at the holders' option, the Series O shares can be converted into common shares at 95% of the then market price of the common shares, but the Company has the option to satisfy the obligation in cash, a new issue of preferred shares, common shares or a combination thereof.

After April 30, 1999, the Company may elect to convert the Series P shares into common shares at 95% of the then market price of the common shares or, with the agreement of Series P shareholders, into a new issue of preferred shares. In addition, after April 30, 2002, at the holders' option, the Series P shares can be converted into common shares at 95% of the then market price of the common shares, but the Company has the option to satisfy the obligation in cash, a new issue of preferred shares, common shares or a combination thereof.

The dividend rate per share on the Series K, Series L and Series M shares will be redetermined as of November 1, 1994, December 1, 1995, and May 1, 1996, respectively, by one of: direct negotiation between the Company and the holders of such First Preferred Shares; bids solicited from investment dealers; or an auction procedure.

NOTE 11 EQUITY PREFERRED SHARES

On April 28, 1992, the Company issued 12,500,000 Cumulative Equity Second Preferred Shares, Series B (Equity Preferred Shares) at a price of $16.125 per share. The Equity Preferred Shares provide a cumulative annual dividend of $1.25 per share and will be converted automatically into common shares of the Company on August 1, 1995. As a result of the automatic conversion feature, the Company has assumed the conversion of the Equity Preferred Shares took place at their issue date when calculating the weighted average number of shares outstanding and per share data for use in determining net income per share, as described in Note 12.

NOTE 12 COMMON SHARES

The Company is authorized to issue an unlimited number of common shares of no par value. Details of the Company's common shares are:

	Number of Shares (thousands)	Amount (millions of dollars)
Outstanding – January 1, 1991	154,187	424.1
Issued for cash or cash equivalent		
Under public offering	15,500	260.7
Under the dividend reinvestment and share purchase plan	1,654	25.3
Exercise of options	36	0.6
Outstanding – December 31, 1991	171,377	710.7
Issued for cash or cash equivalent		
Under private placement	2,000	34.7
Under the dividend reinvestment and share purchase plan	2,646	45.6
Exercise of options	31	0.5
Cancellation of common shares	(42)	(0.5)
Outstanding – December 31, 1992	176,012	791.0
Issued for cash or cash equivalent		
Under the dividend reinvestment and share purchase plan	**3,905**	**71.4**
Exercise of options	**101**	**1.6**
Cancellation of common shares	**(8)**	**(0.1)**
Outstanding – December 31, 1993	**180,010**	**863.9**

Net Income Per Share

Net income per share for the respective years is calculated by deducting, from net income, dividends applicable to preferred shares (redeemable) of $46.6 million, $46.7 million and $31.8 million for the years ended December 31, 1993, 1992 and 1991, respectively. The result is divided by the weighted average number of equity preferred and common shares outstanding. The weighted average number of shares for the years ended December 31, 1993, 1992 and 1991, are 190,725,610, 181,115,503 and 163,628,231, respectively. Fully diluted earnings per share have not been presented as the effect of potential dilution of convertible debentures, preferred shares Series O and P and options is not material.

Employee Stock Incentive Plan

The Company has a Key Employee Stock Incentive Plan (KESIP). KESIP permits the award of options to purchase the Company's common shares to certain key employees, some of whom are also officers. Options may be exercised at a price which is determined at the time the option is awarded. Generally, 20% of the common shares subject to an option may be purchased at the end of each year following the award date of the option.

Options	Number of Shares (thousands)	Exercise Prices	Shares Exercisable (thousands)
Outstanding at January 1, 1992	1,187	$14.70 - $17.35	285
Granted	466	$17.50	
Exercised	(31)	$14.70 - $17.125	
Cancelled or expired	(14)	$14.70 - $17.125	
Outstanding at December 31, 1992	1,608	$14.70 - $17.50	490
Granted	**444**	**$20.10 - $20.85**	
Exercised	**(101)**	**$14.70 - $17.50**	
Cancelled or expired	**(18)**	**$17.125 - $17.50**	
Outstanding at December 31, 1993	**1,933**	**$14.70 - $20.85**	**871**

KESIP also has a share purchase feature. No shares have been offered or sold to any key employee under this feature since 1987. In connection with the share purchase feature of KESIP, the Company, through a trustee, provided interest free loans to certain of its employees. These loans mature ten years from the date of issue, are included in accounts receivable and are secured by the common shares issued under KESIP. The outstanding balance of these loans totaled $9.3 million, $13.8 million and $17.2 million at December 31, 1993, 1992 and 1991, respectively.

Common Shares Reserved

The maximum number of common shares of the Company that may be issued under KESIP is 15.0 million shares subject to an annual limitation of 1.2 million shares. At December 31, 1993, approximately 8.9 million shares remained to be issued under KESIP. At December 31, 1993, in addition to the shares set aside and reserved for outstanding options, 816,890 common shares have been set aside and reserved for future issuance under KESIP and 550,000 common shares have been reserved for future issuance pursuant to the Company's Employee Savings Plan.

Restriction on Dividends

Certain terms under the Company's preferred share provisions and debt instruments could potentially restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 1993, such terms did not restrict or alter the Company's ability to declare dividends.

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	1993	1992
Subject to regulation	**67.1**	119.8
Not subject to regulation		
Payments on future gas supply	**21.1**	26.5
Unamortized foreign exchange losses	**4.5**	12.8
Other deferred amounts	**9.6**	17.2
	102.3	176.3

The deferred amounts subject to regulation are amortized and recovered or refunded in future periods through the regulatory process.

NOTE 14 PENSION PLANS

The Company has a non-contributory pension plan and a Supplemental Retirement Plan (SRP). The non-contributory pension plan covers all employees who have completed one year of service and provides a defined benefit pension based on length of service and the employee's final average earnings. The SRP provides a supplemental pension benefit to executives upon retirement.

The cost of pension benefits earned by employees is determined using the projected unit credit method prorated over the service life of the employee group. This cost is charged to operations as services are rendered and reflects Management's best estimate of expected plan investment performance, salary escalation, terminations and retirement ages of plan members. Adjustments arising from plan amendments, changes in assumptions and experience gains and losses are amortized on a straight-line basis over the expected average remaining service life of the employee group.

The components of the Company's pension expense are detailed as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Pension costs for benefits earned during the current period	**8.4**	10.3	9.7
Amortization of transition amount and other	**2.2**	1.6	2.2
Net pension expense	**10.6**	11.9	11.9

Contributions determined by the actuary are made annually to the non-contributory pension plan. These are intended to provide for benefits attributed to service to date. Obligations under the SRP are not pre-funded, but are paid directly to retired members of the plan.

The projected funded status of the Company's pension plans is as follows:

December 31 (millions of dollars)	1993	1992
Accumulated benefits based on service to date and current compensation		
Vested	**161.4**	145.6
Non-vested	**4.9**	4.8
Accumulated benefit obligation	**166.3**	150.4
Additional amounts related to projected salary increases	**62.0**	61.0
Actuarial present value of current accumulated pension benefits	**228.3**	211.4
Pension plan assets	**213.1**	188.0
Deficit	**15.2**	23.4

Pension plan assets are stated at average market value and include marketable equity securities and corporate and government debt securities.

The discount rate used in determining the actuarial present value of the projected pension benefit obligation was 8.0% (1992 - 8.5%). The rate of return on pension plan assets was estimated to be 8.0% per annum (1992 - 8.5%).

NOTE 15 RELATED PARTY TRANSACTIONS

Revenue from and payments by the Company to certain of its affiliates were as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Operating Revenues			
ANG (1992 amount from date of investment)	**46.7**	18.1	–
Ocean State Power Plant	**25.7**	21.8	1.8
Great Lakes System	–	–	53.5
Charges for Gas Transmission Services			
Great Lakes System	**242.6**	257.5	145.2
TQM	**72.7**	76.5	74.3
Northern Border Pipeline Company	**21.8**	15.7	–

Amounts due from and to related parties were as follows:

December 31 (millions of dollars)	1993	1992
Accounts receivable	**5.8**	8.2
Accounts payable	**28.1**	28.6

In 1991, the Great Lakes System ceased being a seller of natural gas and, as a result, no longer purchases natural gas from the Company. This decrease in gas sales to the Great Lakes System has been offset by increased direct gas sales to the former customers of the Great Lakes System.

NOTE 16 DECREASE/(INCREASE) IN OPERATING WORKING CAPITAL

The following table sets forth the changes in the components of operating working capital:

Year ended December 31 (millions of dollars)	1993	1992	1991
Decrease/(increase) in accounts receivable	**50.2**	(98.3)	(46.5)
Decrease/(increase) in other current assets	**14.3**	(42.2)	(2.4)
Increase in accounts payable	**14.9**	30.8	113.6
Increase/(decrease) in income taxes payable	**50.1**	(105.2)	95.2
(Decrease)/increase in interest accrued	**(17.3)**	12.2	8.2
	112.2	(202.7)	168.1

NOTE 17 COMMITMENTS AND CONTINGENCIES

(a) Gas Supply

During 1982 and 1983, the Company concluded arrangements (referred to as the Topgas Programs) with syndicates of banks and substantially all of its producers to finance its payments for prepaid gas incurred up to and including the contract year ended October 31, 1983. Pursuant to the Topgas Programs, Alberta corporations controlled by the banking syndicates (the Topgas Companies) advanced approximately $2.7 billion to these producers in respect of these payments for prepaid gas. Pursuant to contractual arrangements, recovery of the advances commenced in 1984 and is being effected in installments by the nomination for delivery of prepaid gas. Scheduled recovery of the prepaid gas for the Topgas Programs will be completed in 1994. As at December 31, 1993, approximately $142 million (December 31, 1992 - $358 million) remained outstanding. The Company has indemnified the Topgas Companies against losses arising due to the inability or failure of a producer to deliver prepaid gas. At December 31, 1993, this indemnity amounts to $25 million (December 31, 1992 - $36 million). Interest costs associated with the advances are being recovered by the Company through producers' agreements or pursuant to regulations made by the Province of Alberta.

The Company's risk with respect to the possibility that a producer will fail to deliver prepaid gas as scheduled is mitigated by a number of factors including cross-dedication of reserves on certain contracts with producers and joint and several obligations in multi-party contracts. In addition, the Company monitors the financial and deliverability capabilities of producers and implements special recovery measures as necessary.

(b) Legal Proceedings and Other Investigations

The Company and certain associated operations are subject to various legal proceedings and other investigations as part of ongoing business operations.

(i) Canada

The Company has been charged under the Fisheries Act of Canada, the Ontario Water Resources Act and the Environmental Protection Act of Ontario. These charges allege that, during the construction of new pipeline in Ontario, the Company discharged sediment into water. The Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its consolidated financial position or on its results from operations and accordingly has made no provision in its accounts.

(ii) United States

United States subsidiaries of the Company hold a 50% interest in the Great Lakes System. In 1990, Great Lakes Gas Transmission Company (Great Lakes), as operator of the Great Lakes System, received notice from the United States Environmental Protection Agency (EPA) indicating that Great Lakes may be considered a potentially responsible party (PRP) in the ongoing remediation of an oil-contaminated refinery site in Minnesota. Great Lakes had sold less than 10,000 gallons of used oil to the refinery in 1976. The EPA has suggested a method of remediation that is estimated to cost approximately US$55 million to all PRP's. Great Lakes is discussing appropriate, less expensive methods of remediation with the EPA. Great Lakes' portion of the used oil represents approximately 0.29% of the total oil sent to the refinery, according to preliminary estimates. Great Lakes has taken the position that contributions to site remediation should be based on the amount of oil sent to the site by each party.

Great Lakes is currently evaluating the extent of its liability, the possible availability of insurance proceeds and the possible recovery of remedial costs through ratemaking procedures. Great Lakes is unable to determine, at this time, what effect the resolution of this matter will have on its financial position. No provision has been made in the accounts of Great Lakes or the Company with respect to this action.

A United States subsidiary of the Company holds a 29% general partnership interest in the Iroquois Gas Transmission System L.P. (Iroquois). Another United States subsidiary of the Company operates the Iroquois pipeline system on behalf of Iroquois. Iroquois is the subject of civil investigation by the U.S. Attorney's Office to determine whether civil environmental violations were committed during construction of the Iroquois pipeline. Iroquois has denied that such violations occurred and has asserted that all concerns raised by governmental authorities during construction had been fully responded to. No proceedings in connection with this civil investigation have been commenced by the U.S. federal government against Iroquois. The Federal Energy Regulatory Commission and the Army Corps of Engineers have also requested information regarding construction of certain of Iroquois facilities.

In addition, a criminal investigation has been initiated against Iroquois and its environmental consultant by the U.S. Attorney's Office in conjunction with the EPA and the Federal Bureau of Investigation (FBI). According to a press release issued by the FBI in June 1992, areas under investigation include possible environmental violations, wire fraud, mail fraud and providing false information or concealment of information from federal agencies in conjunction with the construction of the base pipeline. No criminal charges have been filed in connection with this matter.

Iroquois believes that the pipeline construction and right-of-way activities were conducted in a legal and responsible manner. No provision has been made in the accounts of Iroquois or of the Company with respect to these investigations.

(c) Guarantee of Debt of Talisman

As at December 31, 1993, the Company has guaranteed approximately $60 million of the outstanding debt of Talisman Energy Inc. (Talisman) which was assumed by Talisman on its acquisition of Encor Inc. (Encor) on May 21, 1993. This amount matures in December 1994. At December 31, 1992, the Company had guaranteed approximately $69 million of Encor's outstanding debt.

NOTE 18 SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GAAP

The Company's consolidated financial statements are prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following sets forth the reconciliation of these differences:

(a) Net income in accordance with U.S. GAAP

Year ended December 31 (millions of dollars except per share amounts)	1993	1992	1991
Net income for the year as reported	**355.6**	328.7	251.2
U.S. GAAP adjustments			
Foreign currency translation (1)	**8.3**	14.8	15.3
Income taxes (2)	**(9.6)**	(11.7)	(10.6)
Income before extraordinary item and cumulative effect of the application of SFAS 109	**354.3**	331.8	255.9
Reduction of income taxes from the application of prior years' losses (2)	–	11.7	10.6
Cumulative effect of the application of SFAS 109	**10.0**	–	–
Net income for the year in accordance with U.S. GAAP	**364.3**	343.5	266.5
Per share data			
Income before extraordinary item and cumulative effect of the application of SFAS 109	**$1.61**	$1.57	$1.37
Extraordinary item	–	0.07	0.06
Cumulative effect of the application of SFAS 109	**0.05**	–	–
Net income	**$1.66**	$1.64	$1.43

(1) Under Canadian GAAP, the Company defers unrealized foreign exchange gains and losses with respect to its borrowings in foreign currencies and amortizes them over the remaining life of such debt. Under U.S. GAAP, such gains and losses are immediately recognized in income in the period.

(2) This reconciliation reflects the application of Statement of Financial Accounting Standards No. 109 (SFAS 109) "Accounting for Income Taxes" effective January 1, 1993, on a prospective basis. Among other provisions, SFAS 109 requires that deferred income tax expense be calculated as the change in the deferred income tax asset or liability in the year. Prior to applying SFAS 109, the reduction of income taxes arising from the application of prior years' losses was reported separately for U.S. GAAP purposes as an extraordinary item.

(b) As a result of the Canadian/U.S. GAAP reconciliation and additional disclosure requirements under U.S. GAAP, the Statement of Consolidated Financial Position changes are:

	Amount reported under Canadian GAAP		Amount as adjusted to conform with U.S. GAAP	
December 31 (millions of dollars)	**1993**	1992	**1993**	1992
Regulatory Asset	**–**	–	**927.6**	–
Deferred Amounts	**102.3**	176.3	**97.8**	164.1
Deferred Income Taxes	**71.3**	95.6	**1,014.7**	95.6
Equity Preferred Shares and Common Shareholders' Equity	**2,314.3**	2,098.2	**2,286.3**	2,072.4

SFAS 109 also requires that a deferred income tax liability be recorded for cost-of-service regulated utilities even if the taxes payable method is used for tollmaking purposes. As deferred income taxes of such utilities are recoverable through future revenues, a corresponding regulatory asset has also been recorded under U.S. GAAP. These deferred tax assets and liabilities are adjusted for changes in enacted tax rates.

Deferred income taxes under U.S. GAAP consist of a deferred income tax liability of $1,227.2 million, net of a deferred income tax asset of $212.5 million. Included in the deferred income tax liability is approximately $840.8 million resulting from amounts deducted for income tax depreciation in excess of amounts deducted for accounting purposes. Also included in the deferred income tax liability is $325.6 million, related to the additional taxes that will be paid when the regulatory asset related to the deferred income tax liability is recovered through the tollmaking process. The deferred income tax asset consists largely of the future income tax benefits of utility deferrals recorded in the Gas Transmission segment and the tax effect of the future revenue reductions related thereto. An additional deferred income tax asset in the amount of $86.5 million, resulting from differences in the carrying value of investments for accounting and income tax purposes and operating and capital loss carryforwards, has been fully provided for through the use of a valuation allowance. The valuation allowance was reduced in 1993 by $13.7 million due to the utilization of operating loss carryforwards.

Under U.S. GAAP, Equity Preferred Shares and Common Shareholders' Equity has been reduced by the amounts receivable from employees in connection with KESIP.

(c) Additional information required under U.S. GAAP

(i) The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards No. 106 (SFAS 106) "Employers' Accounting for Postretirement Benefits Other Than Pensions". SFAS 106 requires accrual of the expected costs of providing postretirement benefits during the period in which employees render services. While the Company is not required to adopt SFAS 106 for U.S. GAAP purposes until January 1, 1995, it estimates that had it adopted SFAS 106 effective January 1, 1993, an accumulated unrecorded postretirement benefit obligation would amount to approximately $22 million. Under SFAS 106, this could be amortized over the estimated average remaining service life of the employees or recognized in its entirety in the year of adoption. The Company has not yet determined the method it will use to adopt SFAS 106.

(ii) In accordance with the provisions of FASB's Statement of Financial Accounting Standards No. 107 "Disclosure about Fair Value of Financial Instruments," the Company has estimated the fair value of each class of financial instruments. The carrying amount of cash and short-term investments approximates fair value. The value of interest rate and currency swaps, foreign exchange contracts, forward rate agreements and natural gas market related instruments is approximately $3.0 million at December 31, 1993, closing market rates (December 31, 1992 - $42.0 million). The fair values of long-term debt, convertible debentures and preferred shares (redeemable) have been estimated to be $5.4 billion, $191.8 million and $599.5 million, respectively, at December 31, 1993 (December 31, 1992 - $5.1 billion, $167.0 million and $605.0 million, respectively), by reference to quoted market prices for the same or similar issues.

(iii) The components of the Company's pension expense in accordance with U.S. GAAP are detailed as follows:

Year ended December 31 (millions of dollars)	1993	1992	1991
Current service cost	8.1	7.9	7.5
Interest on accrued benefits	17.2	16.9	15.5
Expected return on pension assets	(15.7)	(15.6)	(13.3)
Amortization of prior service cost	2.2	1.9	2.8
Amortization of transition amount	(0.3)	(0.3)	(0.3)
Net pension expense	11.5	10.8	12.2

There is no significant impact on income for any difference between Canadian and U.S. GAAP pension expense, as a major portion of the difference would be deferred and recognized in income in the future when recovered in the tollmaking process.

The funded status of the Company's pension plans for U.S. GAAP purposes is as follows:

December 31 (millions of dollars)	1993	1992
Projected benefit obligation	228.3	211.4
Pension assets-market value	230.2	197.6
Surplus/(deficit)	1.9	(13.8)
Unrecognized net (gain)/loss	(20.0)	2.7
Unrecognized prior service cost	17.0	17.6
Unrecognized net transitional assets	(4.9)	(5.2)
Pension (liability)/asset	(6.0)	1.3

The amount of deficit reported above is different than the amount calculated under Canadian GAAP as a result of differences in the valuation of pension assets. Under U.S. GAAP, pension assets are at market value.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

The following sets forth selected quarterly financial data for the four quarters of 1993 and 1992 in millions of dollars except for per share amounts:

Three Months ended (unaudited)	Mar. 31	June 30	Sept. 30	Dec. 31
1993				
Operating revenues	**1,115.2**	**978.7**	**1,003.3**	**1,144.9**
Net income	**87.3**	**91.7**	**87.8**	**88.8**
Net income per share	**$0.40**	**$0.42**	**$0.40**	**$0.40**
1992				
Operating revenues	925.9	844.7	853.0	1,133.9
Net income	79.5	81.0	83.9	84.3
Net income per share	$0.39	$0.39	$0.39	$0.39

PRICE RANGE OF COMMON SHARES

The Company's common shares are listed on the Vancouver, Alberta, Winnipeg, Toronto, Montréal and New York stock exchanges. The Toronto Stock Exchange is the principal market on which the Company's common shares are traded. The following table sets forth the quarterly high and low sales prices of the Company's common shares as reported by The Toronto Stock Exchange and New York Stock Exchange, respectively:

	Toronto Stock Exchange (Cdn. dollars)		New York Stock Exchange (US dollars)	
	High	Low	High	Low
1993				
First Quarter	**$19.25**	**$16.13**	**$15.50**	**$12.75**
Second Quarter	**$20.13**	**$18.13**	**$15.75**	**$14.50**
Third Quarter	**$21.88**	**$19.50**	**$16.63**	**$14.63**
Fourth Quarter	**$21.13**	**$19.00**	**$15.88**	**$14.50**
1992				
First Quarter	$18.13	$16.25	$15.75	$13.75
Second Quarter	$17.63	$16.00	$14.63	$13.38
Third Quarter	$18.50	$17.50	$15.50	$14.50
Fourth Quarter	$18.13	$17.25	$14.63	$13.50

INVESTMENT INFORMATION FOR FOREIGN INVESTORS

In Canada there are no restrictions on the export or import of capital which affect the Company's remittance of dividends, interest or other payments to its non-resident security holders.

Dividends paid by the Company to shareholders outside of Canada are subject to Canadian non-resident withholding tax. This tax is generally at the rate of 15% for the United States and other countries where Canadian tax treaties apply and 25% for non-treaty countries.

Interest payable on the Company's debt securities held by non-residents, which are not exempt institutions, will be subject to Canadian withholding tax depending upon the terms and provisions of such securities.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

This Plan allows common and preferred shareholders of the Company to purchase additional common shares of the Company by reinvesting their cash dividends and by making optional cash payments.

Shares acquired through the Plan with reinvested dividends are purchased at 95% of the average market price and shares acquired with optional cash payments are purchased at 100% of the average market price. There are no brokerage commissions payable under the Plan since participants purchase the new common shares directly from the Company and all administrative costs of the Plan are paid by the Company.

Shareholders who wish more information regarding the Plan should contact the Shareholder Services Department at the Company's Corporate Offices.

REGISTERED COMMON SHAREHOLDERS AND DIVIDENDS

As of December 31, 1993, there were 18,168 registered holders of common shares.

Quarterly dividends of 19 cents per common share were declared in each of the first three quarters of 1992. The 1992 fourth quarter dividend was increased to 21 cents per common share and remained constant throughout the first three quarters of 1993. In the fourth quarter of 1993, the quarterly dividend was increased to 23 cents per common share.

Certain terms under the Company's preferred share provisions and debt instruments could potentially restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 1993, such terms did not restrict or alter the Company's ability to declare dividends.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth the Company's consolidated ratio of earnings to fixed charges for the periods indicated:

Year ended December 31	**1993**	1992	1991	1990	1989
Ratio of earnings to fixed charges (1)	**2.0**	2.0	1.8	1.8	1.8

(1) The ratio of earnings to fixed charges is determined by dividing the financial charges incurred by the Company (before capitalized interest) into its income from continuing operations before financial charges and income taxes, excluding undistributed income of less than 50% owned persons. The financial data used in the calculation of the ratio of earnings to fixed charges was obtained from financial statements that were prepared in accordance with Canadian generally accepted accounting principles.

The following table sets forth the Company's consolidated ratio of earnings to fixed charges for the periods indicated, determined in the manner described in (1) above, but utilizing similar information determined in accordance with United States generally accepted accounting principles.

Year ended December 31	**1993**	1992	1991	1990	1989
Ratio of earnings to fixed charges	**2.0**	2.0	1.9	1.9	2.0

For information regarding significant differences between Canadian and United States generally accepted accounting principles, see Note 18 to the Company's consolidated financial statements.

FIVE-YEAR FINANCIAL AND OPERATING HIGHLIGHTS

FINANCIAL (millions of dollars except where indicated)	1993	1992	1991	1990	1989
Operating Results					
Operating revenues	**4,242.1**	3,757.5	3,094.1	3,033.2	3,082.9
Net income for the year	**355.6**	328.7	251.2	214.9	196.7
Assets					
Plant, property and equipment (net)					
Gas transmission	**6,430.5**	5,876.1	4,727.0	3,469.5	3,115.1
Gas marketing	**6.0**	7.1	6.9	8.9	7.6
Associated operations and other	**107.8**	117.4	113.0	91.7	81.0
Total assets	**8,157.8**	8,236.6	6,604.7	5,239.8	4,623.4
Capitalization					
Long-term debt	**4,170.0**	3,894.8	3,369.6	2,859.3	2,443.7
Preferred shares					
Subject to mandatory redemption	**75.0**	75.0	155.0	155.0	240.0
Not subject to mandatory redemption	**507.8**	513.3	384.0	234.3	103.7
Equity preferred shares and common shareholders' equity	**2,314.3**	2,098.2	1,659.3	1,280.4	1,169.2
Cash Flow Data					
Funds generated from operations	**477.5**	486.9	337.1	341.1	289.7
Capital expenditures and investments (net)	**748.3**	1,462.2	1,569.7	579.2	677.4
Share Statistics					
Net income per share for the year	**$1.62**	$1.56	$1.34	$1.23	$1.09
Dividends declared per common share	**$0.86**	$0.78	$0.73	$0.69	$0.68
Funds generated from operations per share	**$2.50**	$2.69	$2.06	$2.22	$1.91
Return on Average Common Equity	**13.92%**	14.78%	14.77%	15.31%	12.22%
Number of Common Shareholders, December 31	**18,168**	18,639	18,871	17,733	19,254
Number of Regular Employees, December 31	**1,764**	1,791	1,784	1,757	1,765
U.S. GAAP Information					
Net income for the year	**364.3**	343.5	266.5	225.9	247.2
Net income per share for the year	**$1.66**	$1.64	$1.43	$1.31	$1.42
Equity preferred shares and common shareholders' equity	**2,286.3**	2,072.4	1,615.2	1,214.4	1,086.1

OPERATING	1993	1992	1991	1990	1989
Gas transmission volumes delivered (billions of cubic feet)					
Annual	**2,127.8**	1,971.3	1,655.1	1,509.6	1,418.0
Maximum per day	**7.1**	5.7	5.5	5.1	5.0
Kilometres of pipeline – including loop line	**13 687**	13 106	12 242	11 400	11 039
Compressor power (kilowatts)	**1,626,900**	1,581,600	1,282,300	1,210,700	1,059,400

(As of January 1, 1994)

DIRECTORS

J. V. Raymond Cyr, O.C.
Chairman
Bell Canada and
Director
BCE Inc., Montréal

Robert E. Dineen, Jr.
Partner, Shearman & Sterling
New York

Wendy Dobson
Professor, Faculty of Management
University of Toronto, Toronto

L. Yves Fortier, C.C., Q.C.
Chairman and a Senior Partner
Ogilvy Renault, Montréal

Robert H. Jones
Corporate Director, Winnipeg

Thomas E. Kierans
President and Chief Executive Officer
C.D. Howe Institute, Toronto

The Hon. Donald S. Macdonald, P.C.
Counsel, McCarthy Tétrault, Toronto

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Chairman and Chief Executive Officer
TransCanada PipeLines Limited, Calgary

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

Harry G. Schaefer
Chairman of the Board
TransAlta Utilities Corporation, Calgary

Neil J. Stewart
Corporate Director, Victoria

Robert Stollery
Chairman, PCL Employee Holdings Ltd.
Edmonton

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Royal Bank of Canada, Toronto

George W. Watson
President
TransCanada PipeLines Limited, Calgary

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W. Dobson
L.Y. Fortier
R.H. Jones
T.E. Kierans

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G.J. Maier - *Chairman*
J.V.R. Cyr
D.S. Macdonald
A.R. Taylor

Human Resources Committee
A.R. Taylor - *Chairman*
J.V.R. Cyr
T.E. Kierans
H.C. Pinder, Sr.
N.J. Stewart

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R.H. Jones
D.S. Macdonald
G.J. Maier
R. Stollery

EXECUTIVE OFFICERS

Gerald J. Maier
Chairman and Chief Executive Officer

George W. Watson
President

George M. Hugh
Chief Operating Officer

Robert A.M. Young
Senior Vice-President, Law

Gavin J. Couper
President, Western Gas Marketing Limited

Michael Durnin
Senior Vice-President, Engineering
and Operations

A. Jake Epp
Senior Vice-President

Robert J. C. Reid
Senior Vice-President

Robert B. Hodgins
Vice-President and Chief Financial Officer

Ray T. Smith
Vice-President and Controller

John W. Stinson
Vice-President, Human Resources

OFFICERS

John K. Archambault
Vice-President

Edward J. Brown
Assistant Controller

H. Frederick Button
Vice-President

Doron J. Cohen
Vice-President, Information Systems
and Telecommunications

Robert B. Cohen
Vice-President, Government
and Public Affairs

Max Feldman
Vice-President, Transportation Planning
and Gas Control

Steve Jakymiw
Vice-President, Transportation Services
and Rates

Alison T. Love
Corporate Secretary
and Associate General Counsel

Barry G. Luft
Vice-President, Storage
and Extraction

James M. Murray
General Counsel, Litigation & Regulatory
and Assistant Corporate Secretary

Gary G. Penrose
General Manager, Taxation

David E. Reid
Vice-President, Engineering

David Russell
Vice-President, Power Generation
and International Business

Lawrence W. Sloan
Assistant Secretary

John G. Walker
Vice-President, Operations

Bruce A. Westell
Treasurer

Paul R. Wigle
Vice-President, Gas Supply and
Transportation Economics

Arthur A. Wilkins
Vice-President, Gas Reserves

(As of January 1, 1994)

PRINCIPAL SUBSIDIARIES

Western Gas Marketing Limited

Gerald J. Maier
Chairman

Gavin J. Couper
President

Ray T. Smith
Senior Vice-President

Steven D. Becker
Vice-President, Trading Operations and Risk Management

John W.A. McDonald
Vice-President, Marketing

Douglas I.D. McLean
General Counsel and Corporate Secretary

Murray A. Ross
Vice-President, Sales, Northern Region

Lawrence W. Sloan
Vice-President, Gas Supply and Liquids

Cancarb Limited

Robert D. Hale
President and
Chief Operating Officer

Iroquois Pipeline Operating Company

George M. Hugh
Chairman

Craig R. Frew
President

Paul Bailey
Vice-President, Finance and Administration

Bernard M. Otis
Vice-President, Transmission

Jeffrey A. Bruner
General Counsel and Assistant Secretary

CORPORATE OFFICES

Head Office
TransCanada PipeLines Tower
111 - 5th Avenue S.W.
Calgary, Alberta
T2P 3Y6
Telephone: (403) 267-6100

Toronto Office
55 Yonge Street, 8th Floor
Toronto, Ontario
M5E 1J4
Telephone: (416) 869-2111

SUBSIDIARY OFFICES

Western Gas Marketing Limited
530 - 8th Avenue S.W.
Calgary, Alberta
T2P 3V6
Telephone: (403) 269-5611

Cancarb Limited
P.O. Box 310
1702 Brier Park Crescent N.W.
Medicine Hat, Alberta
T1A 7G1
Telephone: (403) 527-1121

Iroquois Pipeline Operating Company
1 Corporate Drive, Suite 606
Shelton, Connecticut 06484
Telephone: (203) 925-7200

AFFILIATES

Alberta Natural Gas Company Ltd
Foothills Pipe Lines (Sask.) Ltd.
Great Lakes Gas Transmission System, L.P.
Trans Québec & Maritimes Pipeline Inc.
Northern Border Pipeline Company
Iroquois Gas Transmission System, Limited Partnership
Ocean State Power

COMMON SHARES

Transfer Agents and Registrars:
Montreal Trust Company,
Montréal, Toronto, Winnipeg,
Regina, Calgary and Vancouver

Bank of Montreal Trust Company,
New York

PREFERRED SHARES

Transfer Agents and Registrars:
Montreal Trust Company,
Montréal, Toronto, Winnipeg,
Regina, Calgary and Vancouver

$2.80 cumulative redeemable first preferred shares

Cumulative redeemable first preferred shares series O and series P

Cumulative redeemable retractable first preferred shares series N

Cumulative redeemable perpetual first preferred shares series K, series L and series M are transferable at the office of the Company

Cumulative equity second preferred shares series B

FIRST MORTGAGE PIPE LINE BONDS

Trustee:
National Trust Company, Toronto
(The R-M Trust Company, as Agent)

Co-Registrars U.S. Series:
16% and 16¾% U.S.
The R-M Trust Company, as Agent for National Trust Company, Trustee and Morgan Guaranty Trust Company of New York

Co-Registrars U.K. Series:
16½% U.K.
The R-M Trust Company, as Agent for National Trust Company, Trustee and The Royal Bank of Scotland plc, London, England

DEBENTURES

Trustee and Registrar Canadian Series:
Montreal Trust Company,
Montréal, Toronto, Winnipeg,
Calgary and Vancouver

11.40% series J,
10.45% series K,
10.80% series L,
10.55% series M,
11.10% series N,
10.50% series O,
10.50% series P,
10.625% series Q,
11.85% series R,
11.90% series S,
11.65% series T,
11.80% series U,
9.80% series V,
9.45% series W

Trustee and Registrar U.S. Series:
Bank of Montreal Trust Company,
New York
9.875%, 8.625% and 8.50%

CONVERTIBLE SUBORDINATED DEBENTURES

Trustee and Registrar Canadian Series:
Montreal Trust Company, Calgary
10.426%

SUBORDINATED DEBENTURES

Trustee and Registrar U.S. Series:
The Bank of Nova Scotia Trust Company of New York
9.125%

CANADIAN MEDIUM TERM NOTES

Trustee:
The R-M Trust Company,
Montréal, Toronto, Winnipeg,
Regina, Calgary and Vancouver

U.S. MEDIUM TERM NOTES

Trustees:
Bank of Montreal Trust Company,
New York (unsubordinated notes)

The Bank of Nova Scotia Trust Company of New York (subordinated notes)

STOCK EXCHANGES

Common and preferred shares are listed on the Toronto, Montréal, Vancouver, Alberta and Winnipeg stock exchanges. The common shares are also listed on the New York Stock Exchange.

STOCK SYMBOLS

Common shares: TRP
$2.80 cumulative redeemable first preferred shares: TRP.PR.A
Cumulative redeemable retractable first preferred shares:
Series N: TRP.PR.N
Series O: TRP.PR.O
Cumulative equity second preferred shares: TRP.PR.P

Statistical information available to analysts may be obtained by contacting Gary Lloyd, director, Investor Relations, at one of the numbers below:

1-800-361-6522
Canada and U.S. Mainland

(403) 267-6100
Main Switchboard

The Company's Annual Information Form, as filed with the Canadian Securities Commissions and as filed under Form 40-F with the Securities and Exchange Commission in the United States, is available to common shareholders at no charge by writing to:

Corporate Secretary
TransCanada PipeLines Limited
P.O. Box 1000
Station M
Calgary, Alberta
T2P 4K5

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez vous adresser à TransCanada PipeLines, bureau du secrétaire.

METRIC CONVERSION TABLE

The conversion factors set out below provide only approximate conversions. To convert from Metric to Imperial, multiply by the factor indicated. To convert from Imperial to Metric, divide by the factor indicated.

Metric	Imperial	Factor
kilometres	miles	0.62
millimetres	inches	0.04
kilowatts	horsepower (HP)	1.34
gigajoules	million British thermal units (MMBtu)	0.95
cubic metres*	cubic feet	35.3
cubic metres (liquid measure)	barrels	6.29
degrees Celsius	degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees to convert to Celsius subtract 32 degrees, then divide by 1.8

* The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15° Celsius.

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Susan Jaques, page 7 (left),
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