## TABLE OF CONTENTS


| | |
|---|---|
| **CONSOLIDATED FINANCIAL REVIEW** | |
| Highlights | 9 |
| Results-at-a-Glance | 9 |
| **FORWARD-LOOKING INFORMATION** | 11 |
| **OVERVIEW AND STRATEGIC PRIORITIES** | |
| TransCanada Overview | 12 |
| TransCanada's Strategy | 12 |
| Core Businesses and Significant Developments in 2005 | |
| Gas Transmission | 13 |
| Power | 15 |
| Operational Excellence and "SPIRIT" | 16 |
| Competitive Strength and Enduring Value | 17 |
| Outlook | 17 |
| **GAS TRANSMISSION** | |
| Highlights | 19 |
| Results-at-a-Glance | 22 |
| Financial Analysis | 23 |
| Opportunities and Developments | 24 |
| Regulatory Developments | 28 |
| Business Risks | 30 |
| Other | 32 |
| Outlook | 33 |
| **POWER** | |
| Highlights | 35 |
| Results-at-a-Glance | 38 |
| Financial Analysis | 39 |
| Opportunities and Developments | 48 |
| Business Risks | 48 |
| Other | 49 |
| Outlook | 50 |
| **CORPORATE** | 51 |
| **LIQUIDITY AND CAPITAL RESOURCES** | 52 |
| **CONTRACTUAL OBLIGATIONS** | 54 |
| **FINANCIAL AND OTHER INSTRUMENTS** | 57 |
| **RISK MANAGEMENT** | 62 |
| **CRITICAL ACCOUNTING POLICY** | 64 |
| **CRITICAL ACCOUNTING ESTIMATE** | 64 |
| **ACCOUNTING CHANGES** | 64 |
| **DISCONTINUED OPERATIONS** | 66 |
| **SUBSIDIARIES AND INVESTMENTS** | 67 |
| **SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA** | 68 |
| **SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA** | 69 |
| **FOURTH QUARTER 2005 HIGHLIGHTS** | 71 |
| **SHARE INFORMATION** | 72 |
| **OTHER INFORMATION** | 72 |
| **GLOSSARY OF TERMS** | 73 |

*The Management's Discussion and Analysis (MD&A) dated February 27, 2006 should be read in conjunction with the audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the company) and the notes thereto for the year ended December 31, 2005. Amounts are stated in Canadian dollars unless otherwise indicated.*

## CONSOLIDATED FINANCIAL REVIEW

## HIGHLIGHTS

### Net Income

- In 2005, net income was $1,209 million or $2.49 per share compared to $1,032 million or $2.13 per share in 2004.

### Net Earnings

- In 2005, TransCanada's net income from continuing operations (net earnings) increased $229 million to $1,209 million or $2.49 per share compared to $980 million or $2.02 per share in 2004.
- Excluding gains on sale of assets, TransCanada's net earnings increased $66 million to $852 million or $1.75 per share compared to $786 million or $1.62 per share.

### Investing Activities

- In 2005, TransCanada invested more than $2.0 billion in the Gas Transmission and Power businesses.

### Balance Sheet

- In 2005, TransCanada's shareholders' equity increased by more than $0.6 billion.
- The total market value of the company's common shares at December 31, 2005 was $17.9 billion, an increase of $3.4 billion from December 31, 2004.

### Dividend

- In January 2006, the Board of Directors of TransCanada raised the quarterly dividend on the company's outstanding common shares five per cent to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006.

**CONSOLIDATED RESULTS-AT-A-GLANCE**
*Year ended December 31 (millions of dollars except per share amounts)*

| | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Net Income** | | | |
| Continuing operations | **1,209** | 980 | 801 |
| Discontinued operations | **–** | 52 | 50 |
| | **1,209** | 1,032 | 851 |
| **Net Income Per Share – Basic** | | | |
| Continuing operations | **$2.49** | $2.02 | $1.66 |
| Discontinued operations | **–** | 0.11 | 0.10 |
| | **$2.49** | $2.13 | $1.76 |

**SEGMENT RESULTS-AT-A-GLANCE**
*Year ended December 31 (millions of dollars except per share amounts)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Gas Transmission Net Earnings** | | | |
| Excluding gains | **635** | 579 | 622 |
| Gain on sale of PipeLines LP units | **49** | – | – |
| Gain on sale of Millennium | **–** | 7 | – |
| | **684** | 586 | 622 |
| **Power Net Earnings** | | | |
| Excluding gains | **253** | 209 | 220 |
| Gain on sale of Paiton Energy | **115** | – | – |
| Gains related to Power LP | **193** | 187 | – |
| | **561** | 396 | 220 |
| **Corporate** | **(36)** | (2) | (41) |
| **Net Income** | | | |
| Continuing Operations[1] | **1,209** | 980 | 801 |
| Discontinued Operations | **–** | 52 | 50 |
| | **1,209** | 1,032 | 851 |
| **Net Income Per Share – Basic** | | | |
| Continuing Operations[2] | **$2.49** | $2.02 | $1.66 |
| Discontinued Operations | **–** | 0.11 | 0.10 |
| | **$2.49** | $2.13 | $1.76 |

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| [1]**Net Income from Continuing Operations:** | | | |
| Excluding gains | **852** | 786 | 801 |
| Gains related to Paiton Energy, PipeLines LP, Power LP and Millennium | **357** | 194 | – |
| | **1,209** | 980 | 801 |
| [2]**Net Income Per Share from Continuing Operations:** | | | |
| Excluding gains | **$1.75** | $1.62 | $1.66 |
| Gains related to Paiton Energy, PipeLines LP, Power LP and Millennium | **0.74** | 0.40 | – |
| | **$2.49** | $2.02 | $1.66 |

Net income for the year ended December 31, 2005 was $1,209 million or $2.49 per share compared to $1,032 million or $2.13 per share for 2004 and $851 million or $1.76 per share for 2003. This includes net income from discontinued operations of $52 million or $0.11 per share in 2004 and $50 million or $0.10 per share in 2003, reflecting income recognized on the initially deferred gains relating to the disposition in 2001 of the company's Gas Marketing business.

TransCanada's net earnings for the year ended December 31, 2005 were $1,209 million or $2.49 per share compared to $980 million or $2.02 per share and $801 million or $1.66 per share in 2004 and 2003, respectively. Net earnings for 2005 included after-tax gains of $193 million on the sale of the company's interest in TransCanada Power, L.P. (Power LP), $115 million on the sale of the company's interest in P.T. Paiton Energy Company (Paiton Energy) and $49 million on the sale of TC PipeLines, LP (PipeLines LP) units, while net earnings for 2004 included after-tax gains of $187 million on the sale of the ManChief and Curtis Palmer assets to Power LP and the recognition of dilution gains resulting from a reduction in TransCanada's ownership interest in Power LP and other previously deferred gains, as well as a $7 million after-tax gain on sale of the company's equity interest in the Millennium Pipeline Project (Millennium).

Excluding the total gains of $357 million recorded in 2005 and total gains of $194 million recorded in 2004, net earnings for 2005 of $852 million or $1.75 per share increased $66 million or $0.13 per share compared to 2004. This was mainly due to an increase in net earnings from the Gas Transmission and Power businesses, partially offset by an increase in net expenses in Corporate.

Excluding the gains on sale of PipeLines LP units in 2005 and the Millennium interest in 2004, the $56 million increase in net earnings from the Gas Transmission business for 2005 compared to 2004 was primarily attributable to a $57 million increase as a result of a full year of net earnings from the Gas Transmission Northwest System and the North Baja System (collectively GTN), acquired on November 1, 2004. In addition, Gas Transmission's net earnings for 2005 included approximately $35 million ($13 million related to 2004 and $22 million related to 2005) as a result of the April 2005 National Energy Board (NEB) decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II). This decision dealt with capital structure and included an increase in the deemed common equity ratio to 36 per cent from 33 per cent for 2004, which was also effective for 2005 under the 2005 tolls settlement. The increase in Canadian Mainline's net earnings for 2005 as a result of this NEB decision was partially offset by a combination of a lower average investment base, lower earnings related to operating cost savings and a decrease in the approved rate of return on common equity (ROE) in 2005 compared to 2004. These increases in net earnings were partially offset by lower net earnings from TransCanada's Other Gas Transmission businesses.

Excluding the gains related to the company's investments in Power LP in 2004 and 2005 and Paiton Energy in 2005, Power's net earnings for 2005 increased $44 million compared to 2004 as a result of higher operating and other income from Bruce Power (being the collective investments in Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B)) and Eastern Operations, partially offset by a lower contribution from Western Operations and higher general, administrative, support costs and other.

The increase in net expenses of $34 million in Corporate in 2005 compared to 2004 was primarily due to increased net interest expense on higher average long-term debt and commercial paper balances in 2005 as well as the release in 2004 of previously established restructuring provisions.

The increase in net earnings of $179 million or $0.36 per share in 2004 compared to 2003 included $187 million of gains related to Power LP and a $7 million gain on sale of Millennium. Excluding these gains, 2004 net earnings decreased $15 million from 2003. Lower net earnings in the Gas Transmission and Power businesses were partially offset by reduced net expenses in Corporate. The decrease in net earnings, excluding gains, of $43 million in the Gas Transmission business in 2004 compared to 2003 was primarily due to a decline in the Alberta System's and Canadian Mainline's net earnings. The $11 million decrease in Power's net earnings, excluding gains, in 2004 compared to 2003 was primarily due to a $19 million after-tax settlement with a counterparty in 2003. The decrease in net expenses of $39 million in Corporate in 2004 compared to 2003 was primarily due to the positive impacts of income tax, foreign exchange related items and release of the restructuring provisions in 2004.

## FORWARD-LOOKING INFORMATION

*Certain information in this MD&A includes forward-looking statements. All forward-looking statements are based on TransCanada's beliefs and assumptions based on information available at the time the assumptions were made. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. By its nature, such forward-looking information is subject to various risks and uncertainties, including those material risks discussed in this MD&A under "Gas Transmission – Business Risks" and "Power – Business Risks", which could cause TransCanada's actual results and experience to differ materially from the anticipated results or other expectations expressed. The material assumptions in making these forward-looking statements are disclosed in this MD&A under the headings "Overview and Strategic Priorities", "Gas Transmission – Opportunities and Developments", "Gas Transmission –*

*Outlook", "Power – Opportunities and Developments" and "Power – Outlook". Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.*

## TRANSCANADA OVERVIEW

TransCanada is a leading North American energy infrastructure company with a strong focus on natural gas transmission and power generation opportunities located in regions in which it has significant competitive advantages. Natural gas transmission and power are complementary businesses for TransCanada. They are driven by similar supply and demand fundamentals, they are both capital intensive businesses, and they use similar technology and operating practices. They are also businesses with significant long-term growth prospects.

North American natural gas demand is growing and is mainly driven by the demand for electricity. Experts predict that demand for electricity will increase at an average annual rate of approximately two per cent over the next ten years primarily due to a growing population and an increase in gross domestic product. A large part of this growth is expected to be met through higher utilization of natural gas-fired power generating plants that were built as part of the significant capacity additions that occurred in many North American markets over the last five years.

Nuclear facilities have played, and will continue to play, a significant role in supplying North America with power and new nuclear capacity is expected to come on stream over time. Coal-fired plants remain the largest source of electric power in North America and coal reserves are significant. However, the long lead times required to complete new coal and nuclear projects, the associated environmental and socio-economic issues, the high capital costs and the difficulty in locating these plants near load centres may impede the development and completion of new coal or nuclear generation over the next five to ten years. As a result, North America is expected to continue to rely on natural gas-fired generation to satisfy its growing electricity needs in the near term. This is expected to lead to a significant increase in natural gas consumption. Natural gas demand in North America, including Mexico, is expected to grow to approximately 92 billion cubic feet per day (Bcf/d) by 2015, an increase of 16 Bcf/d when compared to 2005. New natural gas-fired power generation is expected to account for approximately 10 Bcf/d of that growth.

While growing demand will provide a number of opportunities, the natural gas industry also faces a number of challenges. North America has entered a period when it will no longer be able to rely solely on traditional sources of natural gas supply to meet its growing needs. Current high natural gas prices suggest that North America is in a period of transition and significant change. Natural gas supply is tight and this is likely to continue until major investments are made in the infrastructure required to bring new supply to market. Looking forward, production from North America's traditional basins is expected to essentially remain flat over the next decade. An increase in production in the United States Rockies will likely only offset declines in other basins, including the Gulf of Mexico. This outlook for traditional basins means that northern gas and offshore liquefied natural gas (LNG) will be required to fill the expected shortfall between supply and demand. TransCanada is well positioned in North America to serve growing power demand in the near term and to bring new natural gas supplies to market in the medium to longer term.

## TRANSCANADA'S STRATEGY

TransCanada's strong position is the direct result of successfully executing its corporate strategy which was first adopted in 2000. While the plan has evolved over time in response to actual and anticipated changes in the business environment, it fundamentally remains the same. Today, TransCanada's corporate strategy consists of the following five components:

- Grow the North American Gas Transmission business.
- Maximize the long-term value of existing Gas Transmission assets.
- Grow the North American Power business.

- Drive for operational excellence.
- Maximize TransCanada's competitive strength, its opportunities and options, and its enduring value.

## Gas Transmission

*Strategy*

The company's strategy in Gas Transmission is focused on growing its North American business while maximizing the long-term value of its existing natural gas transmission assets. In order to grow the Gas Transmission business, TransCanada is focusing its efforts on expanding and extending its existing systems to connect new supply to growing markets, increasing its ownership in partially-owned entities, acquiring or constructing pipelines that provide it with a significant regional presence, expanding into crude oil transmission and in the long term, connecting new sources of supply in the form of northern natural gas and LNG.

Over the past 50 years, TransCanada has developed significant expertise in large-diameter, cold-climate natural gas pipeline design, construction, operation and maintenance. It has also developed significant expertise in the design, optimization and operation of large gas turbine compressor stations. Today, TransCanada operates one of the largest, most sophisticated, remote-controlled pipeline networks in the world with a solid reputation for safety and reliability. TransCanada also has strong project development and management skills and is committed to the highest levels of operational excellence. The company's strong financial position allows it to build large-scale infrastructure and act quickly on quality opportunities as they arise.

In addition to growing the North American Gas Transmission business, the company continues to place a strategic priority on maximizing the long-term value of its wholly-owned pipelines. Efforts in this area are focused on achieving a fair return on invested capital, developing highly competitive tariff structures, and streamlining and harmonizing processes and tariff provisions for and among TransCanada's regulated pipelines. Further, the company continues to work collaboratively with its customers to develop and implement new services that deliver value to customers while sustaining TransCanada's Gas Transmission business.

*Existing Pipelines*

TransCanada's natural gas transmission assets link the Western Canada Sedimentary Basin (WCSB) with premium North American markets. With more than 41,000 kilometres (km) of pipeline, the company's wholly-owned gas transmission network is one of the largest in North America.

In 2005, the wholly-owned Alberta System gathered 66 per cent of the natural gas produced in Western Canada, equal to 17 per cent of total North American production. TransCanada exports gas from the WCSB to Eastern Canada as well as the U.S. West, Midwest and Northeast through four wholly-owned pipeline systems:

- the Canadian Mainline;
- the Gas Transmission Northwest System;
- the Foothills System; and
- the BC System.

TransCanada also exports gas from the WCSB to Eastern Canada as well as the U.S. West, Midwest and Northeast through six pipeline systems in which TransCanada holds the following ownership interests:

- Trans Québec & Maritimes System (TQM) – 50 per cent;
- Great Lakes Gas Transmission System (Great Lakes) – 50 per cent;
- Iroquois Gas Transmission System (Iroquois) – 44.5 per cent;
- Portland Natural Gas Transmission System (Portland) – 61.7 per cent;
- Northern Border Pipeline (Northern Border) – 4 per cent; and
- Tuscarora Gas Transmission System (Tuscarora) – 7.6 per cent.

*Northern Development*

In 2005, TransCanada continued to pursue pipeline opportunities to move both Mackenzie Delta and Alaska North Slope natural gas to markets throughout North America. If the Mackenzie Gas Pipeline Project and the Alaska Highway Pipeline Project are constructed and connected to TransCanada's existing infrastructure, they will represent additional growth opportunities for TransCanada and enhance the long-term viability and value of the company's existing Gas Transmission business, especially the wholly-owned pipelines.

*Mexico*

In June 2005, TransCanada was awarded a contract to construct, own and operate a natural gas pipeline in east-central Mexico. The 36 inch, 125 km Tamazunchale Pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz and transport natural gas to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada expects to invest approximately US$181 million in the project with a planned in-service date of December 1, 2006. The pipeline will be designed to transport initial volumes of 170 million cubic feet per day (mmcf/d). Under the contract, the capacity of the Tamazunchale Pipeline is expected to be expanded beginning in 2009 to approximately 430 mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale. TransCanada continues to explore other pipeline and energy infrastructure opportunities in Mexico.

*LNG*

TransCanada continues to work toward gaining regulatory approval for its two LNG projects: Cacouna in Québec, a joint venture with Petro-Canada; and the Broadwater Energy project (Broadwater), offshore of New York State in Long Island Sound, a joint venture with Shell US Gas & Power LLC (Shell). TransCanada, on behalf of Broadwater, filed a formal application with the U.S. Federal Energy Regulatory Commission (FERC) on January 30, 2006 for federal approval to construct and operate Broadwater.

*Natural Gas Storage*

The company's initiatives in the natural gas storage business are a logical extension of its Gas Transmission business. TransCanada believes Alberta-based natural gas storage will continue to serve market needs and could play an important role should northern gas be connected to North American markets. In the first quarter of 2005, TransCanada started development of a natural gas storage facility near Edson, Alberta. The Edson facility is expected to have a capacity of approximately 60 petajoules (PJ) and will connect to TransCanada's Alberta System. In addition, in 2004, the company secured a long-term contract with a third party for existing Alberta-based natural gas storage capacity, increasing from 20 PJ in 2005 to 30 PJ in 2006 and to 40 PJ in 2007. These initiatives, combined with the company's current 60 per cent ownership interest in CrossAlta Gas Storage & Services Ltd. (CrossAlta), position TransCanada to become one of the largest natural gas storage providers in Western Canada. With more than 130 PJ of storage capacity by 2007, TransCanada will own or lease approximately one-third of the natural gas storage capacity available in Alberta.

*Oil Transmission*

In November 2005, TransCanada, ConocoPhillips Company and ConocoPhillips Pipe Line Company (CPPL), a wholly-owned subsidiary of ConocoPhillips Company, signed a Memorandum of Understanding (MOU) which commits ConocoPhillips Company to ship crude oil on the proposed Keystone oil pipeline (Keystone pipeline), and gives CPPL the right to acquire up to a 50 per cent participating interest in the pipeline. On January 31, 2006, TransCanada announced that through the binding Open Season held in fourth quarter 2005 it had secured firm, long-term contracts totalling 340,000 barrels per day of crude oil with an average term of 18 years. The Keystone pipeline, expected to cost approximately US$2.1 billion, will have an initial capacity to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta to Patoka, Illinois through a 2,960 km pipeline system.

*Regulatory*

In 2005, TransCanada's principal regulatory activities and events included:

- a decision by the NEB to increase the deemed equity ratio of the Canadian Mainline to 36 per cent from 33 per cent following the completion of the hearings of the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II);
- a negotiated settlement with respect to 2005 Canadian Mainline tolls;

- a revenue requirement settlement for 2005, 2006 and 2007 for the Alberta System;
- a hearing before the Alberta Energy and Utilities Board (EUB) on the rate design of the Alberta System, with potential implications for the competitiveness of the Alberta System;
- an agreement with the Canadian Association of Petroleum Producers (CAPP) and other stakeholders to increase the deemed common equity ratios on the Foothills System and the BC System to 36 per cent from 30 per cent, effective January 1, 2006; and
- commencement of settlement negotiations with its Canadian Mainline shippers regarding 2006 tolls.

## Power

TransCanada has built a substantial power business over the past decade. The power plants and power supply that TransCanada owns, operates and/or controls, including projects under construction, represent approximately 6,700 megawatts (MW) of power generation capacity in Canada and the U.S. The company's power assets are concentrated in two main regions – the western business focused in Alberta and the eastern business focused in the Northeastern U.S. and Eastern Canada markets.

*Strategy*

TransCanada's strategy for growth and value creation in Power is driven by four principles:

- acquire low-cost, base-load generation in markets it knows. The company believes that being a low-cost provider is critical to being successful in volatile power markets;
- develop low-risk, greenfield generation projects, backed by long-term input and sales contracts with quality counterparties. The company believes that long-term contracts are an essential part of most greenfield development projects;
- actively participate in markets that are in transition. The changes that took place in Alberta and the Northeastern U.S., and the changes that continue in Ontario and Québec, allow the company to capture opportunities that are created as a result of power markets in transition; and
- optimize the existing asset portfolio by running the company's facilities as efficiently and cost-effectively as possible through operational excellence.

TransCanada's ability to successfully execute its strategy is directly related to the following core competencies in the power business:

- broad understanding of North American energy markets and a deep understanding of its core markets in Alberta, Eastern Canada and the Northeastern U.S.;
- active participation in deregulated and deregulating markets;
- ability to structure transactions and manage risk which is critical to mitigating volatility and uncertainty for industrial customers and shareholders;
- a strong financial position which allows the company to build large-scale infrastructure and gives it the ability to act quickly on quality opportunities as they arise; and
- strong project development, project management and operational skills.

In 2005, TransCanada continued to add to its diverse portfolio of quality power generation assets.

*Bécancour and Cartier Wind*

Throughout 2005, TransCanada continued to advance the Bécancour and Cartier Wind Energy (Cartier Wind) power projects. Construction of the 550 MW Bécancour cogeneration plant near Trois Rivières, Québec, remains on schedule to begin operations in September 2006. The 739.5 MW Cartier Wind project, 62 per cent owned by TransCanada, awarded construction contracts in late 2005, and is expected to commence construction in early 2006. Located in the

Gaspésie region of Québec, the first of the six projects that comprise Cartier Wind is anticipated to be commissioned beginning in late 2006 with the remaining projects being commissioned through to 2012. The entire power output from both Bécancour and Cartier Wind will be supplied to Hydro-Québec Distribution (Hydro-Québec) under 20 year power purchase contracts.

*TC Hydro*
In April 2005, TransCanada acquired from USGen New England, Inc. (USGen), hydroelectric generation assets (TC Hydro) with total generating capacity of 567 MW, for approximately US$503 million. These are low operating cost power generation assets serving the New England market.

*Bruce Power*
In October 2005, Bruce Power and the Ontario Power Authority (OPA), entered into a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. The capital program for the restart and refurbishment work is expected to total approximately $4.25 billion and TransCanada's approximate $2.125 billion share will be financed through capital contributions to 2011. Work to refurbish Units 1 and 2 was initiated in 2005 and the first unit is expected to be on-line in 2009. Restarting Units 1 and 2 will add approximately 1,500 MW to Bruce Power's existing generation capacity of 4,700 MW. All of the Bruce A output will be sold to the OPA under fixed price contract terms.

As a result of the agreement between Bruce Power and the OPA, and the decision by Cameco Corporation (Cameco) not to participate in the restart and refurbishment program, a new partnership, Bruce A, was created. The Bruce A partnership subleases the Bruce A facilities, comprised of Units 1 to 4, from Bruce B. The effect of these transactions was that TransCanada and BPC Generation Infrastructure Trust (BPC) each incurred a net cash outlay of $100 million and as at December 31, 2005 each owned a 47.9 per cent interest in Bruce A.

*Sheerness PPA*
In December 2005, TransCanada acquired the remaining rights and obligations under the 756 MW Sheerness Power Purchase Arrangement (PPA) from the Alberta Balancing Pool for $585 million. The remaining term of the PPA is 15 years. The Sheerness power plant, which consists of two low-cost coal-fired thermal power generating units, is located approximately 230 km northeast of Calgary, Alberta.

*Grandview*
Construction of the 90 MW Grandview natural gas-fired cogeneration power plant located in Saint John, New Brunswick, was completed at the end of 2004. It was commissioned in January 2005. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output is sold to Irving Oil (Irving).

TransCanada expects its Power business to continue to be a key growth driver. The company is committed to growing the Power business through asset acquisitions, selected greenfield developments and further expansions of its existing business. TransCanada's goal is to build and establish a diverse portfolio of high quality assets that deliver strong returns to shareholders.

## OPERATIONAL EXCELLENCE AND "SPIRIT"

In addition to growing its Gas Transmission and Power businesses, TransCanada is committed to an operational excellence business model. The company's focus is on being a low-cost, reliable and safe operator that provides responsive services to its customers in an effective and timely manner.

The company's values guide the way business is conducted at TransCanada. Within TransCanada, these values are commonly referred to as "SPIRIT". They are the principles that direct how the company works and they include: Social responsibility, Passion, Integrity, Results, Innovation and Teamwork. The company's commitment to these values helps ensure it maintains its reputation as one of North America's premier energy infrastructure companies.

## COMPETITIVE STRENGTH AND ENDURING VALUE

TransCanada's strategy also focuses on developing and enhancing those strengths that are at the core of its corporate success:

- developing excellence in value-creating strategy, analysis and investment execution;
- continuing to improve its financial capacity and flexibility;
- maintaining its corporate governance initiatives and its culture of honesty and integrity;
- developing and sustaining its relationships and reputation with all key stakeholders; and
- creating sustainable organizational and people strengths.

These initiatives bring competitive advantage and facilitate the effective delivery of results for the company's Gas Transmission and Power businesses.

TransCanada has approximately 2,350 employees who through their talent, integrity, hard work and results provide the company with a strong competitive advantage driven by industry-leading expertise in pipeline and power operations, depth of market and industry knowledge, financial acumen and exceptional infrastructure project capabilities.

## OUTLOOK

TransCanada's corporate strategy is underpinned by a long-term focus on growing its Gas Transmission and Power businesses in a disciplined and measured manner. This strategy was initiated in 2000 and has been consistently followed. In 2006 and beyond, the company's net earnings and cash flow, combined with a strong balance sheet, are expected to continue to provide the financial flexibility for TransCanada to capture further opportunities and create additional long-term value for shareholders.

In Gas Transmission, the company will continue to focus its efforts on maximizing the long-term value from its pipeline and natural gas storage assets, including efforts to connect new long-term supply to growing markets. This focus will take a variety of forms in 2006 including:

- working with natural gas producers and the Aboriginal Pipeline Group (APG), including participating in regulatory proceedings as may be required, to advance the Mackenzie Gas Pipeline Project with an ultimate goal of connecting new northern natural gas supply to TransCanada's existing facilities and obtaining an equity ownership interest in the project;
- working with natural gas producers and the State of Alaska to advance the proposed Alaska Highway Pipeline Project, thereby connecting another source of northern natural gas supply to TransCanada's facilities;
- advancing development of the Cacouna and Broadwater LNG facilities which will, upon completion, connect new natural gas supply to existing and growing markets in Eastern North America. TransCanada will have a 50 per cent ownership interest in each of these projects and these new natural gas supplies are expected to increase natural gas flows on certain of TransCanada's natural gas pipeline systems;
- advancing development of the innovative Keystone pipeline which includes conversion of a portion of TransCanada's existing facilities from natural gas to crude oil transmission, thereby providing cost-effective and much needed pipeline capacity for the Alberta oil sands;
- completing construction of the Tamazunchale natural gas pipeline in Mexico, which is expected at the end of 2006;
- continuing discussions with Canadian Mainline stakeholders towards a settlement on 2006 tolls;
- advancing the expansion of the North Baja System;
- transitioning to the operatorship of Northern Border Pipeline in early 2007; and
- filing a rate case with FERC with a goal of establishing new rates for the Gas Transmission Northwest System.

In addition, Gas Transmission will continue to grow its natural gas storage business in 2006 through completion of the Edson facility, an expanded CrossAlta facility and increased capacity under a long-term contract with a third party. TransCanada will also seek to continue to capitalize on opportunities to increase its ownership in its partially-owned pipelines and acquire interests in new pipelines in markets where TransCanada has a significant regional presence.

In Power, TransCanada has had significant success in growing this segment and, in 2006, will continue to focus its efforts on further growth. As in 2005 and prior years, this growth is expected to come from a combination of greenfield developments, new acquisitions and organic growth within its existing assets and markets. In particular, in 2006, TransCanada is expected to:

- work with Bruce A and its partners to advance the restart and refurbishment of the Bruce A units;
- complete construction of the 550 MW Bécancour power plant in late 2006;
- complete construction of the first of six Cartier Wind projects at the end of 2006 and continue construction of the second wind facility;
- integrate the newly acquired Sheerness PPA into Power's Western Operations; and
- pursue additional greenfield projects and acquisition opportunities in TransCanada's key regional markets.

The following discussion reflects management's expectations for 2006, as discussed throughout this MD&A. A number of risk factors and developments may positively or negatively affect the actual results for 2006, including new acquisitions, advancement of greenfield developments, regulatory decisions and settlements, customer bankruptcies, market changes in commodity prices, weather and interest rates as well as unplanned outages on various Gas Transmission and Power assets. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact TransCanada's net earnings, although this impact is mitigated by partially offsetting exposures in certain of the company's businesses as well as through the company's hedging activities.

In 2006, TransCanada expects reduced net earnings from the Gas Transmission business compared to 2005 (excluding the gain on sale of PipeLines LP units in 2005). The combined effects of an expected net decline in the rate base of each of the Canadian Mainline and Alberta System and the decline in each of their respective allowed ROEs are expected to decrease net earnings on these systems compared to 2005. In addition, reduced firm contract volumes on the Gas Transmission Northwest System, partially due to the effects of customer bankruptcies, are expected to have a slightly negative impact on the Gas Transmission Northwest System results compared to 2005, although it is uncertain what impact the 2006 rate case filing may have on the system's results. Lastly, anticipated lower firm service revenues on certain partially-owned pipelines and a full year of reduced ownership of PipeLines LP are expected to be only partially offset by the effects of a higher allowed deemed common equity component on the Foothills System and the BC System and the expected growth in natural gas storage net earnings.

In the Power business, 2006 net earnings are expected to be higher than in 2005 (excluding the gains on sales related to Power LP and Paiton Energy in 2005) due to higher Bruce Power results reflecting an increased ownership in Bruce A and fewer planned outages, increased contributions from Western Operations reflecting the acquisition of the Sheerness PPA, slightly improved Eastern Operations' results reflecting a full year of TC Hydro operations as well as initial contributions from Bécancour and Cartier Wind expected in late 2006. Offsetting these improved results is the loss of income due to the sale of Power LP in 2005.

In 2006, Corporate is expected to incur higher net expenses compared to 2005 primarily due to the income tax refunds and positive income tax adjustments recorded in 2005 that are not currently expected to recur in 2006. In addition, Corporate's results in 2006 could be impacted by debt levels, interest rates, foreign exchange movements and income tax refunds and adjustments.

## GAS TRANSMISSION

### HIGHLIGHTS

*Net Earnings*

- Net earnings from Gas Transmission increased $98 million to $684 million in 2005 compared to $586 million in 2004.
- This increase is primarily due to a full year of GTN earnings in 2005 and the gain on sale of PipeLines LP units.

*Canadian Mainline*

- The NEB, in its decision on the 2004 Tolls and Tariff Application (Phase II), approved an increase in the deemed common equity component of the Canadian Mainline's capital structure to 36 per cent from 33 per cent, effective January 1, 2004.
- The NEB approved a negotiated settlement of 2005 Canadian Mainline tolls.

*Alberta System*

- The EUB approved a three year revenue requirement settlement negotiated with shippers and other stakeholders. The settlement finalized the 2005 revenue requirement as well as established a framework for calculating the 2006 and 2007 revenue requirements. Most costs are treated on a flow through basis but certain costs have been fixed in each of the three years.

*GTN*

- GTN contributed $71 million of earnings in 2005.
- Successfully integrated into TransCanada's business.

*Foothills System and BC System*

- Following an agreement with CAPP and other stakeholders to increase the deemed common equity component of the capital structure to 36 per cent from 30 per cent for the Foothills System and BC System and discussions with its shippers on those two systems, on December 2, 2005, TransCanada filed applications with the NEB for final 2006 tolls. On December 21, 2005, the NEB approved the Foothills System 2006 tolls as final tolls, effective January 1, 2006. On February 22, 2006, the NEB finalized the BC System's 2006 tolls as filed.

*Other Gas Transmission*

- TransCanada sold approximately 3.5 million common units of PipeLines LP for an after-tax gain on sale of approximately $49 million.
- TransCanada continued to fund the APG participation in the Mackenzie Gas Pipeline Project.
- TransCanada commenced development of a natural gas storage project near Edson, Alberta.
- TransCanada was awarded the contract to construct, own and operate the Tamazunchale Pipeline in east-central Mexico. Construction commenced in 2005.
- TransCanada closed the acquisition of a 3.5 per cent ownership interest in Iroquois, increasing its ownership interest to 44.5 per cent.

**Gas Transmission**

- 1 Canadian Mainline
- 2 Alberta System
- 3 Gas Transmission Northwest System
- 4 Foothills System
- 5 BC System
- 6 North Baja System
- 7 Ventures LP
- 8 Great Lakes
- 9 TQM
- 10 Iroquois
- 11 Portland
- 12 Northern Border
- 13 Tuscarora
- 14 Tamazunchale (under construction)
- 15 Mackenzie Gas Pipeline Project (proposed by producers)
- 16 Alaska Highway Pipeline Project (proposed by TransCanada)

**Oil Pipeline**

- 17 Keystone Pipeline (proposed by TransCanada)

Wholly-owned

Partially-owned

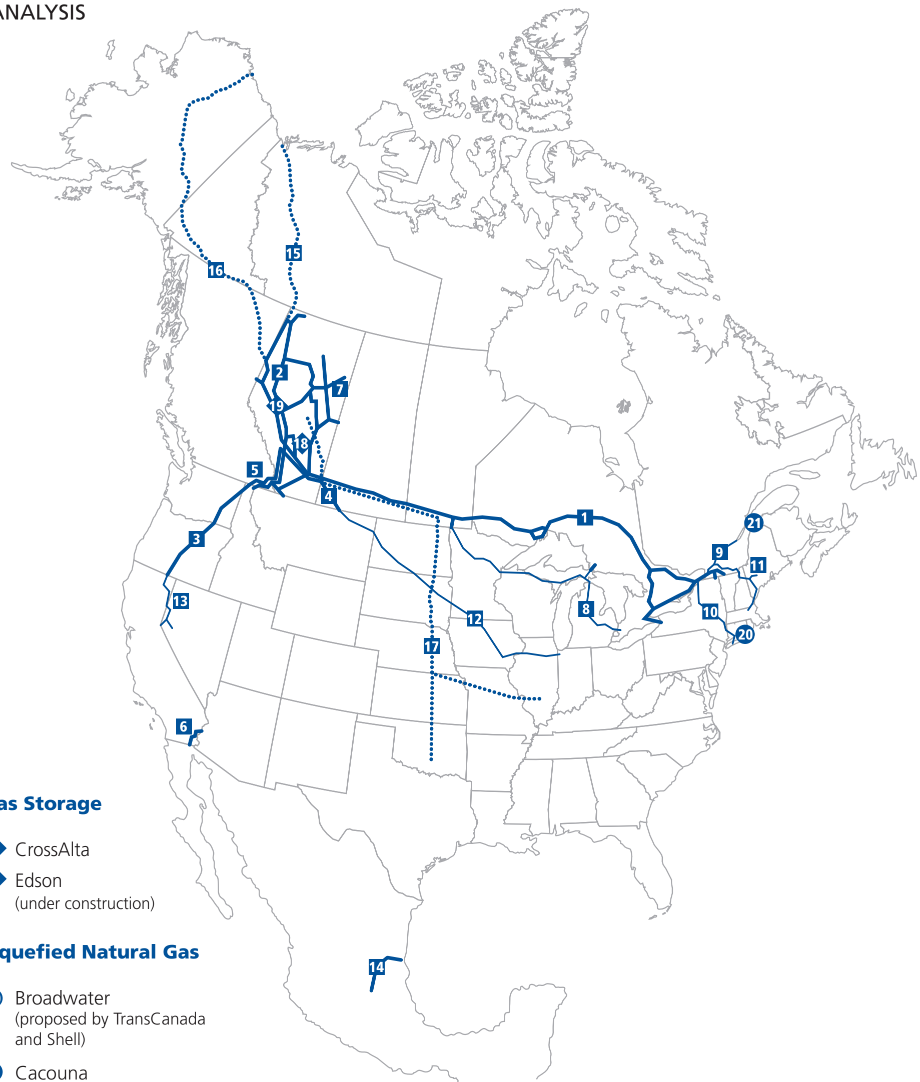
Proposed

**Gas Storage**

- 18 CrossAlta
- 19 Edson (under construction)

**Liquefied Natural Gas**

- 20 Broadwater (proposed by TransCanada and Shell)
- 21 Cacouna (proposed by TransCanada and Petro-Canada)



**CANADIAN MAINLINE** TransCanada's 100 per cent owned, 14,898 km natural gas transmission system in Canada extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

**ALBERTA SYSTEM** TransCanada's 100 per cent owned natural gas transmission system in Alberta gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Canadian Mainline, BC System, the Foothills System and other pipelines. The 23,339 km system is one of the largest carriers of natural gas in North America.

**GAS TRANSMISSION NORTHWEST SYSTEM** TransCanada's 100 per cent owned, 2,174 km natural gas transmission system links the BC System and the Foothills System with Pacific Gas and Electric Company's California Gas Transmission System, with the Northwest Pipeline and with Tuscarora, a partially-owned entity that runs from the Oregon/California border into Nevada.

**FOOTHILLS SYSTEM** TransCanada's 100 per cent owned, 1,040 km natural gas transmission system in Western Canada carries natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

**BC SYSTEM** TransCanada's 100 per cent owned natural gas transmission system extends 201 km from Alberta's western border through British Columbia to connect with the Gas Transmission Northwest System at the U.S. border, serving markets in B.C. as well as the Pacific Northwest, California and Nevada.

**NORTH BAJA SYSTEM** TransCanada's 100 per cent owned, 129 km natural gas transmission system extends from southwestern Arizona to a point near Ogilby, California on the California/Mexico border and connects with the Gasoducto Bajanorte pipeline system in Mexico.

**VENTURES LP** Ventures LP, which is 100 per cent owned by TransCanada, owns a 121 km pipeline and related facilities which supply natural gas to the oil sands region of northern Alberta, and a 27 km pipeline which supplies natural gas to a petrochemical complex at Joffre, Alberta.

**GREAT LAKES** Great Lakes connects with the Canadian Mainline at Emerson, Manitoba and serves markets in central Canada and the eastern and midwestern U.S. TransCanada has a 50 per cent ownership interest in this 3,402 km pipeline system.

**TQM** TQM is a 572 km natural gas pipeline system which connects with the Canadian Mainline and transports natural gas from Montréal to Québec City and to the Portland system. TransCanada holds a 50 per cent ownership interest in TQM.

**IROQUOIS** Iroquois connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the Northeastern U.S. TransCanada has a 44.5 per cent ownership interest in this 663 km pipeline system.

**PORTLAND** Portland is a 474 km pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the Northeastern U.S. TransCanada has a 61.7 per cent ownership interest in Portland.

**NORTHERN BORDER** Northern Border is a 2,010 km natural gas pipeline system which serves the U.S. Midwest from a connection with the Foothills System near Monchy, Saskatchewan. TransCanada indirectly owns approximately 4 per cent of Northern Border through its 13.4 per cent ownership interest in PipeLines LP.

**TUSCARORA** Tuscarora operates a 386 km pipeline system transporting natural gas from the Gas Transmission Northwest System at Malin, Oregon to Wadsworth, Nevada with delivery points in northeastern California and northwestern Nevada. TransCanada owns an aggregate 7.6 per cent interest in Tuscarora, of which 6.6 per cent is held through TransCanada's interest in PipeLines LP.

**TAMAZUNCHALE** TransCanada is currently constructing the Tamazunchale natural gas pipeline in east central Mexico. The 125 km pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada will operate and own 100 per cent of the pipeline. This pipeline is expected to be in service on December 1, 2006.

**TRANSGAS** TransGas is a 344 km natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

**GAS PACIFICO** Gas Pacifico is a 540 km natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada holds a 30 per cent ownership interest in Gas Pacifico.

**INNERGY** INNERGY is an industrial natural gas marketing and distribution company based in Concepción, Chile that markets and distributes natural gas transported on Gas Pacifico. TransCanada holds a 30 per cent ownership interest in INNERGY.

**CROSSALTA** CrossAlta is an underground natural gas storage facility connected to the Alberta System and is located near Crossfield, Alberta. CrossAlta has a working natural gas capacity of 56 PJ with a maximum deliverability capability of 0.45 PJ per day. TransCanada holds a 60 per cent ownership interest in CrossAlta.

**EDSON** TransCanada is currently developing the Edson natural gas storage facility near Edson, Alberta. The Edson facility is expected to have a capacity of approximately 60 PJ and will connect to TransCanada's Alberta System. Storage capacity is expected to be available from the Edson facility, on a phased-in basis, commencing mid-2006.

**BROADWATER** Broadwater, a joint venture with Shell, is a proposed LNG project offshore of New York State in Long Island Sound, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately one Bcf/d of natural gas.

**CACOUNA** Cacouna, a joint venture with Petro-Canada, is a proposed LNG project at Gros Cacouna harbour on the St. Lawrence River, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas.

**GAS TRANSMISSION RESULTS-AT-A-GLANCE**
*Year ended December 31 (millions of dollars)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Wholly-Owned Pipelines** | | | |
| Canadian Mainline | **283** | 272 | 290 |
| Alberta System | **150** | 150 | 190 |
| GTN[(1)] | **71** | 14 | – |
| Foothills System[(2)] | **21** | 22 | 20 |
| BC System | **6** | 7 | 6 |
| | **531** | 465 | 506 |
| **Other Gas Transmission** | | | |
| Great Lakes | **46** | 55 | 52 |
| Iroquois | **17** | 17 | 18 |
| PipeLines LP[(3)] | **9** | 16 | 15 |
| Portland[(4)] | **11** | 10 | 11 |
| Ventures LP[(5)] | **12** | 15 | 10 |
| TQM | **7** | 8 | 8 |
| CrossAlta | **19** | 13 | 6 |
| TransGas | **11** | 11 | 22 |
| Northern Development | **(4)** | (6) | (4) |
| General, administrative, support costs and other | **(24)** | (25) | (22) |
| | **104** | 114 | 116 |
| Gain on sale of PipeLines LP units (after tax) | **49** | – | – |
| Gain on sale of Millennium (after tax) | **–** | 7 | – |
| | **153** | 121 | 116 |
| Net earnings | **684** | 586 | 622 |

(1) TransCanada acquired GTN on November 1, 2004. Amounts in this table reflect TransCanada's 100 per cent ownership interest in GTN's net earnings from the acquisition date.

(2) The remaining ownership interests in the Foothills System, previously not held by TransCanada, were acquired on August 15, 2003.

(3) During 2005, TransCanada decreased its ownership interest in PipeLines LP to 13.4 per cent from 33.4 per cent.

(4) TransCanada increased its ownership interest in Portland to 61.7 per cent from 33.3 per cent in 2003.

(5) TransCanada Pipeline Ventures Limited Partnership.

In 2005, net earnings from the Gas Transmission business were $684 million compared to $586 million and $622 million in 2004 and 2003, respectively. The increase in 2005 compared to 2004 was mainly due to higher net earnings from Wholly-Owned Pipelines and a gain on sale of PipeLines LP units, partially offset by lower net earnings from Other Gas Transmission. The increase in Wholly-Owned Pipelines' net earnings in 2005 was primarily due to a full year of GTN net earnings and higher Canadian Mainline net earnings. Lower net earnings in 2005 from Other Gas Transmission were primarily due to decreased earnings from Great Lakes and PipeLines LP, partially offset by higher earnings for CrossAlta.

The overall decrease of $36 million in 2004 Gas Transmission net earnings compared to 2003 was mainly due to lower net earnings from Wholly-Owned Pipelines. The decrease in Wholly-Owned Pipelines' net earnings in 2004 was primarily due to a reduction in the Alberta System's net earnings, reflecting the EUB's disallowance of certain operating costs in its decision on Phase I of the 2004 General Rate Application (GRA) and in its decision in the generic cost of capital (GCOC) proceeding to allow an ROE in 2004 lower than the return implicit in the 2003 revenue requirement settlement with stakeholders. In addition, net earnings on the Canadian Mainline were lower in 2004 compared to 2003 due to a decline in both the average investment base and the allowed ROE. The addition of GTN had a positive effect on net earnings in 2004.

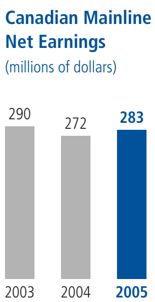
## GAS TRANSMISSION – FINANCIAL ANALYSIS

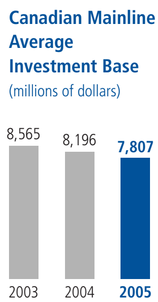
### *Canadian Mainline*

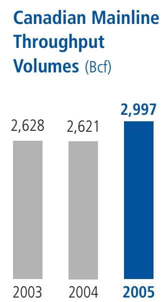
The Canadian Mainline is regulated by the NEB. The NEB sets tolls which provide TransCanada the opportunity to recover projected costs of transporting natural gas, including the return on the Canadian Mainline's average investment base. In addition, new facilities are approved by the NEB before construction begins. Net earnings of the Canadian Mainline are affected by changes in investment base, the ROE, the level of deemed common equity and the potential for incentive earnings.

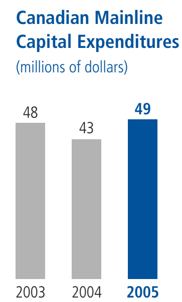
The Canadian Mainline generated net earnings of $283 million in 2005, an increase of $11 million over 2004. The increase in net earnings is primarily due to the NEB's decision on the 2004 Tolls and Tariff Application (Phase II) which included an increase in the deemed common equity ratio to 36 per cent from 33 per cent for 2004 which is also effective for 2005 under the tolls settlement. The Phase II decision resulted in a $35 million ($13 million related to 2004 and $22 million related to 2005) increase to Canadian Mainline's 2005 net earnings compared to 2004. However, this earnings increase was partially offset by the combination of a lower average investment base, lower operating cost savings and a lower approved ROE in 2005. The NEB-approved ROE decreased to 9.46 per cent in 2005 from 9.56 per cent in 2004.

Net earnings of $272 million in 2004 were $18 million lower than 2003 net earnings of $290 million. The decrease was primarily due to a lower average investment base and allowed ROE. The NEB-approved ROE was 9.56 per cent in 2004 compared to 9.79 per cent in 2003.



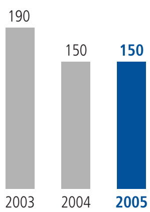

### *Alberta System*

The Alberta System is regulated by the EUB primarily under the provisions of the *Gas Utilities Act (Alberta)* (GUA) and the *Pipeline Act (Alberta)*. Under the GUA, its rates, tolls and other charges, and terms and conditions of service are subject to approval by the EUB. In addition, major facilities are approved by the EUB before construction begins.

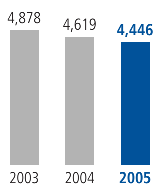
Net earnings of $150 million in 2005 were unchanged from 2004 due to the negative impacts of a lower investment base and a lower approved rate of return in 2005 being offset by the positive impact of higher allowed operating costs in 2005 than in 2004 as a result of cost disallowances in 2004 as a result of the EUB's decision on Phase I of the 2004 GRA. Net earnings in 2004 and 2005 reflect an ROE of 9.60 and 9.50 per cent, respectively, as prescribed by the EUB, on deemed common equity of 35 per cent.

Net earnings in 2004 of $150 million were $40 million lower than 2003 net earnings of $190 million. The decrease was primarily due to the impact of the EUB decisions in respect of Phase I of the 2004 GRA and the GCOC proceeding. The GRA Phase I decision disallowed approximately $24 million of operating costs, and the GCOC decision resulted in a lower return on deemed common equity in 2004 compared to 2003.

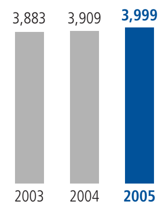
**Alberta System Net Earnings** (millions of dollars)



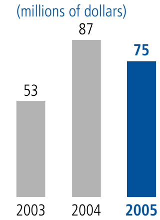

**Alberta System Average Investment Base** (millions of dollars)




**Alberta System Throughput Volumes** (Bcf)




**Alberta System Capital Expenditures** (millions of dollars)




### *GTN*

Both the Gas Transmission Northwest System and the North Baja System operate under fixed rate models, under which maximum and minimum rates for various service types have been ordered by FERC and which GTN is permitted to discount or negotiate on a non-discriminatory basis. The Gas Transmission Northwest System's last filed rate case was in 1994 and it was settled and approved by FERC in 1996. The North Baja System's rates were established in FERC's initial order in 2002, certifying construction and operation of the system. The net earnings of GTN are impacted by variations in volumes delivered and prices charged under the various service types that are provided, as well as by variations in the costs of providing transportation service. Net earnings were $71 million for the year ended December 31, 2005 compared to $14 million for November and December 2004.

### *Other Gas Transmission*

TransCanada's other direct and indirect investments in various natural gas pipelines and gas transmission related businesses are included in Other Gas Transmission. It also includes TransCanada's natural gas storage facilities and project development activities related to TransCanada's pursuit of new pipeline and natural gas and crude oil transmission related opportunities throughout North America.

TransCanada's net earnings from Other Gas Transmission in 2005 were $153 million compared to $121 million and $116 million in 2004 and 2003, respectively. Excluding the gains on sale of PipeLines LP units in 2005 and Millennium in 2004, net earnings for 2005 were $10 million lower compared to 2004. The decrease was primarily due to lower net earnings of Great Lakes as a result of lower short-term revenues and higher operating and maintenance costs, and lower earnings from PipeLines LP as a result of the reduced ownership. Results were also negatively impacted by a weaker U.S. dollar in 2005. These decreases were partially offset by higher earnings from CrossAlta as a result of more favourable natural gas storage conditions in 2005.

Excluding the gain on sale of Millennium, net earnings in 2004 were $2 million lower than 2003. Higher net earnings from CrossAlta and Ventures LP were more than offset by an $11 million positive tax adjustment recorded in TransGas de Occidente S.A. (TransGas) in 2003 and the negative impact of a weaker U.S. dollar in 2004 compared to 2003.

## GAS TRANSMISSION – OPPORTUNITIES AND DEVELOPMENTS

### *Tamazunchale Pipeline*

In June 2005, TransCanada announced it was awarded a contract by Mexico's Comisión Federal de Electricidad (CFE) to construct, own and operate a natural gas pipeline in east-central Mexico. The 36 inch, 125 kilometre Tamazunchale Pipeline will extend from the facilities of Pemex Gas near Naranjos, Veracruz and transport natural gas under a 26 year contract with the CFE to an electricity generation station near Tamazunchale, San Luis Potosi. TransCanada expects to invest approximately US$181 million in the project with a planned in-service date of December 1, 2006.

The pipeline will be designed to transport initial volumes of 170 mmcf/d. Under the contract, the capacity of the Tamazunchale Pipeline is expected to be expanded beginning in 2009 to approximately 430 mmcf/d to meet the needs of two additional proposed power plants near Tamazunchale.

*North Baja System*

In February 2006, the North Baja System filed an application with FERC for a certificate for a two-phase expansion of its existing natural gas pipeline in southern California and the construction of a new pipeline lateral in California's Imperial Valley. The expansion project envisions substantially increasing the capacity of the existing pipeline and allowing for bi-directional flow of natural gas. Natural gas currently flows on the North Baja System southward from its interconnection with El Paso Natural Gas Company at Ehrenberg, Arizona.

The proposed North Baja System expansion links to a corresponding expansion of the Gasoducto Bajanorte line in Mexico owned by Sempra Energy. Together, the expansions may allow for import into the U.S. of up to 2.7 Bcfd/d of natural gas supplied from several potential LNG terminals near Baja California, Mexico, including the Costa Azul terminal that is currently under construction. Shippers have indicated their commercial support for the projects by signing precedent agreements in support of the expansion plan as filed with FERC.

In addition to its FERC certificate of public convenience and necessity (which includes a determination on environmental issues), the project will need various permits and leases from the federal Bureau of Land Management, the California State Lands Commission and other agencies.

*Mackenzie Gas Pipeline Project*

The Mackenzie Gas Pipeline Project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would then connect with the Alberta System. Through 2005, the Mackenzie Gas Pipeline Project continued to progress, with substantial milestones being achieved in reaching agreement with certain of the northern aboriginal groups as to the terms of land access for the pipeline right of way. As a consequence, in late 2005, the project proponents indicated their readiness to proceed to the public hearings phase of the regulatory review of the project. Hearings commenced in January 2006 and are expected to continue throughout 2006.

In 2003, TransCanada entered into an agreement with the Mackenzie Valley Aboriginal Pipeline Limited Partnership (known as the APG) by which TransCanada agreed to finance the APG's one-third share of the pipeline pre-development costs associated with the Mackenzie Gas Pipeline Project. Cumulative advances made by TransCanada in this respect constitute a loan to the APG, which becomes repayable only after the date upon which the pipeline commences commercial operations. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made.

TransCanada's loan advances to the APG were originally estimated to total approximately $90 million, with an acknowledgement that these costs could rise as a result of project delays and increased project costs. Given that the project has experienced delays and is entering into a protracted regulatory hearing process, the total loan advances by TransCanada, on behalf of the APG, are currently forecast to increase to approximately $145 million. These advances are expected to ultimately form part of the rate base of the pipeline, and the loan will subsequently be repaid from the APG's share of available future pipeline revenues or from alternate financing. As at December 31, 2005, TransCanada had funded $87 million of this loan. The ability to recover this investment remains dependent upon the successful outcome of the project. Under the terms of the agreement, TransCanada gains an immediate opportunity to acquire up to five per cent equity ownership of the pipeline at the time of the decision to construct. In addition, TransCanada gains certain rights of first refusal to acquire 50 per cent of any divestitures of existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the producers and the APG sharing the balance.

*Alaska Highway Pipeline Project*

In 2005, TransCanada continued its discussions with Alaska North Slope producers and the State of Alaska relating to the Alaskan portion of the proposed Alaska Highway Pipeline Project. In June 2004, TransCanada filed an application under the State of Alaska's *Stranded Gas Development Act* and requested the State resume processing of its long-pending application for a right-of-way lease across State lands. If the right-of-way lease is approved, TransCanada is prepared to convey the lease to another entity if that entity is willing to connect the final project to TransCanada's pipeline system. The lease conveyance would require an interconnection agreement with TransCanada at the Yukon/Alaska border. TransCanada's Stranded Gas Application is one of three applications currently before the State. In October 2005, the State Administration and ConocoPhillips Company reached a preliminary agreement under the *Stranded Gas Development Act*. On February 21, 2006, the State announced that it had reached a preliminary agreement with BP Resources and ExxonMobil. In addition, on February 21, 2006, the State announced it would be proposing legislation for a new oil and gas production tax regime. It is not expected that a natural gas deal would be submitted to the legislative assembly of Alaska for ratification until after a new oil and gas production tax regime has been enacted.

Foothills Pipe Lines Ltd. (Foothills) holds the priority right to build, own and operate the first pipeline through Canada for the transportation of Alaskan natural gas. This right was granted under the *Northern Pipeline Act of Canada* (NPA), following a lengthy competitive hearing before the NEB in the late 1970s, which resulted in a decision in favour of Foothills. The NPA creates a single window regulatory regime that is uniquely available to Foothills. It has been used by Foothills to construct facilities in Alberta, British Columbia and Saskatchewan which constitute a prebuild for the Alaska Highway Pipeline Project, and to expand those facilities five times, the latest of which was in 1998. TransCanada continues to seek commercial alignment with the Alaska North Slope producers on the Canadian portion of the project. Continued development under the NPA should ensure the earliest in-service date for the project.

*Supply*

In 2005, the upstream energy sector responded to high natural gas prices by drilling a record number of natural gas wells in the WCSB. TransCanada continued to see supply growth from the west central foothills area as well as unconventional production from coalbed methane (CBM), primarily from the Horseshoe Canyon coals located in central Alberta between Edmonton and Calgary.

TransCanada will continue to focus on the cost effective and timely connection of these volumes that will enable customers to access markets where natural gas continues to achieve premium prices. As well, service flexibility will continue to be a focus to ensure TransCanada remains competitive.

*Western Markets*

TransCanada continues to pursue growth opportunities within existing and new natural gas markets. In 2005, TransCanada further pursued the provision of cost effective incremental delivery service into the Fort McMurray, Alberta market. As demand for natural gas continued to grow at unprecedented levels, numerous oil sands projects, both mining and in-situ, were announced in this region in 2005 resulting in incremental natural gas demand.

In late 2004 and throughout 2005, TransCanada executed firm contracts for delivery service to the Fort McMurray area on the Alberta System for volumes in excess of 900 mmcf/d. As a result of the ten and 20 year contracts, TransCanada has filed applications with the EUB to construct new natural gas transmission facilities to serve the contracted demand. The construction will begin in late 2006 with a contracted on-stream date of April 1, 2007. In 2008 and 2009, TransCanada expects to add additional facilities as the Fort McMurray oil sands demand continues to grow.

*Eastern Markets*

Power generation continues to be the primary driver for incremental natural gas demand in Eastern Canada and the U.S. Northeast markets. Power projects that will require significant incremental natural gas volumes continue to be developed and, as a result, the Canadian Mainline is expected to see modest throughput increases in the short to medium term on a long haul basis. Modest expansions, underpinned with long term firm transportation (FT) contracts, are expected to be placed into service in 2006 and 2007 to meet incremental demand in the eastern markets.

Desire for options in accessing natural gas supply is reflected in the continuing trend towards increased demand for short haul contracts by customers in the eastern markets. TransCanada continues to work with these customers to provide service flexibility and optionality.

*LNG*

In September 2005, the village of Cacouna, Québec, voted 57.2 per cent in favour of an LNG terminal to be built in the area. The Cacouna Energy joint venture between Petro-Canada and TransCanada was originally announced in September 2004 and proposes a $660 million project at Gros Cacouna harbour on the St. Lawrence River, capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately 500 mmcf/d of natural gas. TransCanada will operate the planned facility, while Petro-Canada will contract for all of the capacity and supply the LNG. Québec's Ministry of Environment commenced its 45 day public consultation period on February 22, 2006, regarding its next phase for this project.

In November 2004, TransCanada and Shell announced plans to jointly develop an offshore LNG regasification terminal, Broadwater, in the New York State waters of Long Island Sound. The proposed floating storage and regasification unit would be located approximately 15 km off the Long Island coast and 18 km off the Connecticut coast. The proposed terminal would be capable of receiving, storing and regasifying imported LNG with an average send-out capacity of approximately one Bcf/d of natural gas. Broadwater Energy LLC, an entity which will be owned 50 per cent by TransCanada, will own and operate the facility, while Shell will contract for all of the capacity and supply the LNG. The estimated cost of construction is expected to be approximately US$700 million to US$1 billion. Construction of the facility is subject to regulatory approval from U.S. federal and state governments. On January 30, 2006, a formal application was filed with FERC for federal approval to construct and operate Broadwater. Provided the necessary approvals are received, it is expected the facility will be in service in late 2010 or early 2011.

*Natural Gas Storage*

TransCanada's natural gas storage business is situated in Alberta, and is comprised of a long-term natural gas storage contract, 60 per cent ownership in CrossAlta and the wholly-owned Edson facility which is currently under construction. By mid-2007, TransCanada will own or lease more than 130 PJ, or approximately one-third of the natural gas storage capacity in Alberta.

Natural gas market price volatility, partly due to extreme weather, supply disruptions and sharp increases in oil prices, contributed to strong storage values during 2005. TransCanada commenced commercial natural gas storage operations in second quarter 2005 through marketing and optimizing the 20 PJ of contracted natural gas storage capacity. The capacity under contract increases to 30 PJ in 2006 and to 40 PJ in 2007.

TransCanada commenced construction of the Edson facility in early 2005. The construction cost of the project is currently expected to be approximately $270 million, which is a $70 million increase from the initial estimate due to higher drilling and construction costs, and higher base gas costs. The Edson facility is expected to have a capacity of approximately 60 PJ and will connect to TransCanada's Alberta System. Storage capacity is expected to be available from the Edson facility, on a phased-in basis, commencing in mid-2006.

TransCanada also has a 60 per cent interest in the CrossAlta natural gas storage facility, which has a total working natural gas capacity of 56 PJ. In 2005, CrossAlta completed expansion projects that improved the injection and withdrawal rates and increased developed capacity from 44 PJ to 56 PJ.

Current market fundamentals for natural gas storage are expected to remain strong. The imbalance in North American natural gas supply and demand has created natural gas price volatility, resulting in demand for storage service.

TransCanada believes Alberta-based storage will continue to serve market needs and could play an even more important role when northern natural gas is connected to North American markets.

*Keystone Pipeline*
In November 2005, TransCanada, ConocoPhillips Company and CPPL signed an MOU which commits ConocoPhillips Company to ship crude oil on the proposed Keystone pipeline, and gives CPPL the right to acquire up to a 50 per cent ownership interest in the pipeline. On January 31, 2006, TransCanada announced it has secured firm, long-term contracts totalling 340,000 barrels per day with a duration averaging 18 years. The commitments were obtained through the successful completion of a binding Open Season held during fourth quarter 2005. With these commitments from shippers, TransCanada will proceed with regulatory filings for approval of the project.

At an estimated cost of approximately US$2.1 billion, the Keystone pipeline is intended to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to Patoka, Illinois through a 2,960 km pipeline system. The pipeline can be expanded to 590,000 barrels per day with additional pump stations. In addition to approximately 1,730 km of new pipeline construction in the U.S., the Canadian portion of the proposed project includes the construction of approximately 370 km of new pipeline and the conversion of approximately 860 km of TransCanada's existing pipeline facilities from natural gas to crude oil transmission. The Keystone pipeline, upon receipt of the appropriate regulatory approvals in Canada and the U.S., is expected to be in service in 2009. Construction is proposed to begin in late 2007.

Shippers have also expressed interest in proposed extensions of the Keystone pipeline to Cushing, Oklahoma and Fort Saskatchewan, Alberta. TransCanada expects to hold a binding Open Season for these two extensions later in 2006.

TransCanada is in the business of connecting energy supplies to markets and it views this opportunity as another way of providing a valuable service to its customers. Converting one of the company's natural gas pipeline assets for crude oil transportation is an innovative, cost-competitive way to meet the need for pipeline expansions to accommodate anticipated growth in Canadian crude oil production during the next decade.

## GAS TRANSMISSION – REGULATORY DEVELOPMENTS

In 2005, TransCanada's principal regulatory activities included receiving the decision from the NEB regarding the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II); a negotiated settlement with respect to 2005 Canadian Mainline tolls; a three year revenue requirement settlement for the Alberta System; a hearing before the EUB on the rate design of the Alberta System, with potential implications for the competitiveness of the Alberta System; and the successful negotiation with shippers and CAPP for their support on increasing the deemed common equity ratio on the Foothills System and the BC System. TransCanada is also currently in negotiation for a settlement with its Canadian Mainline shippers regarding 2006 tolls.

*Canadian Mainline*
In April 2005, the NEB issued its decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II) which increased the Canadian Mainline deemed common equity to 36 per cent from 33 per cent for 2004 tolls.

In April 2005, the NEB approved TransCanada's application for a negotiated settlement of the 2005 Canadian Mainline tolls as filed. The settlement established operating, maintenance and administration (OM&A) costs for 2005 at $169.5 million with variances between actual OM&A costs in 2005 and those agreed to in the settlement accruing to TransCanada. The majority of other cost elements of the 2005 revenue requirement were to be treated on a flow through basis. Further, the 2005 ROE was set at 9.46 per cent and the deemed common equity component in 2005 reflected the outcome of the NEB's Phase II decision with respect to the Canadian Mainline's 2004 capital structure.

In May 2005, in compliance with the NEB's decision regarding the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II), TransCanada filed separate final tolls applications with the NEB for 2004 and 2005. In June 2005, the NEB issued its decision approving the 2004 and 2005 final tolls applications as filed.

In December 2005, the NEB approved the 2006 interim tolls, effective January 1, 2006. TransCanada is currently engaged in settlement discussions with its stakeholders on matters related to the Canadian Mainline's 2006 tolls and tariff. Pending progress on the settlement discussions, TransCanada intends to file an application for approval of the 2006 tolls and tariff with the NEB in first quarter 2006.

The formula-based ROE for the Canadian Mainline for 2006 is 8.88 per cent.

*Alberta System*

In December 2004, TransCanada filed its 2005 Phase I GRA with the EUB. In March 2005, a settlement was reached with shippers and other interested parties regarding the annual revenue requirements of the Alberta System for the years 2005, 2006 and 2007. The settlement encompasses all elements of the Alberta System revenue requirement, including OM&A costs, return on equity, depreciation, and income and municipal taxes.

In the Alberta System settlement, OM&A costs were fixed at $193 million for 2005, $201 million for 2006, and $207 million for 2007. Any variance between actual OM&A and other fixed costs and those agreed to in the settlement in each year accrue to TransCanada. The majority of other cost elements of the 2005, 2006 and 2007 revenue requirements are treated on a flow through basis.

The return on equity will be calculated annually during the term of the settlement using the EUB formula for the purpose of establishing the annual generic rate of return for Alberta utilities on deemed common equity of 35 per cent. For 2005, ROE under the EUB formula was 9.50 per cent. In addition, depreciation expenses are determined using the depreciation rates and methodology that was proposed to the EUB in the 2004 GRA. Depreciation expense was $303 million in 2005 and is expected to be approximately $285 million in 2006 and $282 million in 2007.

In June 2005, the EUB approved the negotiated settlement of the Alberta System's three year revenue requirement. As stipulated in the settlement, TransCanada then discontinued the action it had commenced to appeal the EUB's disallowance of certain incentive compensation and long-term incentive compensation costs in the 2004 revenue requirement and its work on an application to the EUB to review and vary this same decision.

Interim tolls approved in December 2004 were charged throughout 2005 for transportation service on the Alberta System. With the issuance on February 21, 2006 of the EUB's decision on Phase II of the Alberta System's 2005 GRA, in which the application to retain the Alberta System's current rate design and cost allocation methodologies was approved, final tolls for 2005 can be determined. An application for 2005 final tolls will be made in March 2006.

On December 15, 2005, the EUB approved the application to charge interim tolls for transportation service, effective January 1, 2006. The 2006 interim tolls, which replaced the 2005 interim tolls, will be finalized through an application to the EUB in March 2006 in which the flow-through cost components of the revenue requirement will be updated to reflect actual costs and revenues from the prior year as stipulated under the Alberta System's 2005, 2006 and 2007 revenue requirement settlement.

The formula-based ROE for the Alberta System for 2006 is 8.93 per cent.

*GTN*

TransCanada is preparing a rate case for the Gas Transmission Northwest System that is expected to be filed by summer 2006. The primary reason for a rate case is decreased revenues due to contract non-renewals and shipper defaults. Currently, the Gas Transmission Northwest System has about 12 per cent of its long-term capacity unsubscribed and there is a risk of additional contracts not being renewed during the remainder of 2006. FERC typically suspends the effectiveness of rate increase filings for a five month period, so the company anticipates that the new rates, which are subject to refund pending the final result of the case, would go into effect near the end of 2006.

*Foothills and BC Systems*

TransCanada filed applications with the NEB in early December 2005 for approval of 2006 tolls for the Foothills System and the BC System reflecting an agreement with CAPP and other stakeholders to increase the deemed equity component of the capital structure of each system to 36 per cent from 30 per cent. On December 21, 2005, the NEB approved the Foothills System application as filed. On February 22, 2006, the NEB finalized the BC System's 2006 tolls as filed.

## GAS TRANSMISSION – BUSINESS RISKS

*Competition*

TransCanada faces competition at both the supply end and the market end of its systems. The competition is a result of other pipelines accessing an increasingly mature WCSB and markets served by TransCanada's pipelines. In addition, the continued expiration of long-term FT contracts has resulted in significant reductions in long-term firm contracted capacity on the Canadian Mainline, the Alberta System, the BC System and the Gas Transmission Northwest System, and shifts to short-term firm contracts.

As of December 2004, the WCSB had remaining discovered natural gas reserves of approximately 55 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, additional reserves have continually been discovered to maintain the reserves-to-production ratio at close to nine years. Natural gas prices in the future are expected to be higher than long-term historical averages due to a tighter supply/demand balance which should stimulate exploration and production in the WCSB. However, WCSB supply is expected to remain essentially flat. With the expansion of capacity on TransCanada's wholly- and partially-owned pipelines over the past decade, and the competition provided by other pipelines, combined with significant growth in natural gas demand in Alberta, TransCanada anticipates there will be excess pipeline capacity out of the WCSB for the foreseeable future.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB which connects most of the natural gas processing plants in Alberta to domestic and export markets. The Alberta System has faced, and will continue to face, increasing competition from other pipelines.

The Canadian Mainline is TransCanada's cross-continental natural gas pipeline serving mid-western and eastern markets in Canada and the U.S. The demand for natural gas in TransCanada's key eastern markets is expected to continue to increase, particularly to meet the expected growth in natural gas-fired power generation. Although there are opportunities to increase market share in Canadian and U.S. export markets, TransCanada faces significant competition in these regions. Consumers in the U.S. Northeast have access to an array of pipeline and supply options. Eastern Canadian markets that historically received Canadian supplies only from TransCanada are now capable of receiving supplies from new pipelines into the region that can source Western Canadian, Atlantic Canadian and U.S. supplies.

Over the last few years, the Canadian Mainline has experienced reductions in long haul FT contracts. This has been partially offset by increases in short haul contracts. While decreases in throughput do not directly impact Canadian Mainline earnings, such decreases will impact the competitiveness of its tolls. Over the course of 2005, strong natural gas prices in Eastern Canada and the Northeast U.S. resulted in higher than anticipated flows on the Canadian Mainline to serve those markets. In addition to increases in flow, the Canadian Mainline has also experienced an increase in short-term contracts and a resulting decrease in tolls. Looking forward, in the short to medium term, there is expected to be limited opportunity to further reduce tolls by increasing long haul volumes on the Canadian Mainline. Further, throughput and contract levels are expected to return to more modest levels.

The Gas Transmission Northwest System must compete with other pipelines to access natural gas supplies as well as to access markets. Transportation service capacity on the Gas Transmission Northwest System provides customers with access to supplies of natural gas primarily from the WCSB and serves markets in the Pacific Northwest, California and Nevada. These three markets may also access supplies from other competing basins in addition to supplies from the WCSB. Historically, natural gas supplies from the WCSB have been competitively priced in relation to natural gas supplies from the other supply regions serving these markets. The Gas Transmission Northwest System experienced contract non-renewals in 2005 and additional contracts may not be renewed in 2006. Natural gas transported from the WCSB on the Gas Transmission Northwest System competes in the California and Nevada markets against supplies from the Rocky Mountain and southwest U.S. supply basins. In the Pacific Northwest market, natural gas transported on the Gas Transmission Northwest System competes against Rocky Mountain gas supply as well as additional Western Canadian supply that is transported by the Northwest Pipeline.

Transportation service on the North Baja System provides access to natural gas supplies primarily from both the Permian Basin, located in western Texas and southeastern New Mexico, and the San Juan Basin, primarily located in northwestern New Mexico and Colorado. The North Baja System delivers natural gas to the Gasoducto Bajanorte pipeline at the California/Mexico border, which transports the natural gas to markets in northern Baja California, Mexico. While there are currently no direct competitors to deliver natural gas to the North Baja System's downstream markets, the pipeline may compete with fuel oil which is an alternative to natural gas in the operation of some electric generation plants in the North Baja region.

*Counterparty Risk*

The risk of customer defaults and bankruptcy has always been present. In December 2005, Calpine Corporation and certain of its subsidiaries (Calpine) filed for bankruptcy protection. Calpine has transportation contracts on certain of TransCanada's Canadian and U.S. pipelines. TransCanada presently holds the maximum financial assurances allowable under the respective tariffs. As at February 27, 2006, these transportation contracts had not been accepted or rejected. Should the Calpine contracts with TransCanada's Canadian pipeline systems be rejected, TransCanada considers that it has been prudent in obtaining the maximum financial assurances and would make an application to the regulator for recovery under the current regulatory model of any lost revenue, net of the assurances, and any revenues from the defaulted capacity. Should contracts be rejected on TransCanada's U.S. systems, the unmitigated annual after-tax exposure of the contract obligations is estimated at $10 million for the Gas Transmission Northwest System and $10 million for Portland Natural Gas Transmission System Partnership, in which TransCanada holds a 61.7 per cent ownership interest. Mitigating factors exist which are expected to reduce this exposure including recovery through future general rate case filings, recontracting at maximum or discounted rates where applicable, recontracting as short-term or interruptible service, and recovery from bankruptcy proceedings. The potential impact of such mitigating factors and the resulting net exposure are unknown at this time.

*Financial Risk*

Regulatory decisions continue to have a significant impact on the financial returns for existing and future investments in TransCanada's Canadian wholly-owned pipelines. TransCanada remains concerned the approved financial returns discourage additional investment in existing Canadian natural gas transmission systems. TransCanada had applied for a return of 11 per cent on 40 per cent deemed common equity for both the Canadian Mainline and the Alberta System to the NEB and EUB, respectively. The outcome of these proceedings resulted in the current Canadian Mainline's 36 per cent deemed equity thickness and Alberta System's 35 per cent deemed equity thickness. Additionally, the NEB reaffirmed its return on equity formula, while the EUB set a generic ROE which largely aligns with the formula of the NEB. In 2005, the NEB's ROE formula provided an ROE of 9.46 per cent and the EUB's generic ROE was 9.50 per cent. In 2006, the Canadian Mainline and Alberta System's ROEs decline to 8.88 percent and 8.93 per cent, respectively.

The company remains cognizant of the views and shares the concerns of credit rating agencies regarding the Canadian regulatory environment. Credit ratings and liquidity continue to be at the forefront of investor attention. While recent regulatory decisions increasing the deemed equity component of the capital structure of the company's Canadian pipelines may serve to somewhat mitigate these concerns in the long run, significantly reduced allowed ROE on NEB and EUB regulated pipelines are expected to offset any positive effect in 2006.

*Foreign Exchange*

TransCanada's earnings from GTN, as well as a significant amount of earnings in Other Gas Transmission are generated in U.S. dollars. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Gas Transmission's net earnings, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

*Throughput Risk*

As transportation contracts expire on Great Lakes, Northern Border and GTN, these pipelines will be more exposed to throughput risk and their revenues will more likely experience increased variability. Throughput risk is created by supply and market competition, gas basin pricing, economic activity, weather variability, pipeline competition and pricing of alternative fuels.

## GAS TRANSMISSION – OTHER

*Operational Excellence*

TransCanada continued its commitment to operational excellence in 2005 by further advancing initiatives that will improve the company's ability to provide low-cost, reliable and responsive service to customers. TransCanada continues to pursue the operational excellence strategy in order to continue to be the preferred company for customers wishing to connect new natural gas supplies and markets.

TransCanada maintained a high level of plant operating performance, as measured by the number of operational perfect days on both the Canadian Mainline and the Alberta System. GTN was effectively integrated in 2005, and maintained high levels of operating performance as well.

Receiving the American Society of Mechanical Engineers' inaugural award for pipeline technology in 2005 further recognized the efforts of TransCanada to ensure high reliability levels are sustained over the long term.

The annual Customer Satisfaction Survey, conducted by Ipsos Reid in the fall of 2005, found that TransCanada maintained high levels of overall customer satisfaction and improved significantly in the area of senior management relationships. As part of the Customer Express website, TransCanada launched the "Toll Calculator", an online tool that allows customers to quickly obtain the cost of shipping on TransCanada's wholly-owned and affiliated pipeline systems. Feedback from customers and other stakeholders indicates this tool was well received and support for further development of on-line tools is strong.

Also, 2005 was a very productive year with respect to collaborative efforts with customers. The Tolls Task Force, the Canadian Mainline stakeholder group, produced twenty resolutions in 2005 including process improvements, several service enhancements, a new service and a settlement for the Canadian Mainline. The Tolls, Tariff, Facilities and Procedures committee, the Alberta System stakeholder group, had eleven resolutions in 2005 focusing on greater service flexibility and process efficiency for the Alberta System. Many of these initiatives will result in increasing service flexibility and more efficient service delivery. Productive collaborative processes also result in costs savings for both TransCanada and industry by avoiding costs associated with regulatory proceedings.

In 2006, TransCanada will continue to focus efforts on efficiencies, operational reliability, and environmental and safety performance. Greenhouse gas emissions management programs will continue to receive focused attention and in 2006 further efforts will be undertaken to improve contractor safety performance.

*Safety*

TransCanada worked closely with regulators, customers and communities during 2005 to ensure the continued safety of employees and the public. Pipeline safety performance in 2005 was very good with only one small diameter pipeline line-break located in a relatively remote area of northern Alberta. The break resulted in minimal impact with no injuries or property damage. Under the approved regulatory models in Canada, expenditures on pipeline integrity for the NEB and EUB regulated pipelines have no negative impact on TransCanada's earnings. The company expects to spend approximately $105 million in 2006 for pipeline integrity on its Wholly-Owned Pipelines, which is an increase from the $64 million spent in 2005. The increase is due primarily to initial inspections of the Gas Transmission Northwest System, additional inspections for stress corrosion cracking on the Canadian Mainline and repairs to several water crossings in southern Alberta that were damaged during flood events in June 2005. TransCanada continues to use a rigorous risk management system that focuses spending on issues and areas that have the largest impact on maintaining or improving the reliability and safety of the pipeline system.

*Environment*

In 2005, TransCanada continued to address and assess environmental issues through proactive sampling, monitoring and remediation programs. Activities on the Canadian Mainline included the completion of three ongoing remediation projects, as well as building containment integrity improvement projects at seven compressor stations. All facilities on the Foothills System were assessed through the company's Site Assessment, Remediation and Monitoring program in 2005, along with the majority of facilities on GTN. In addition, the decommissioning and reclamation of four Canadian

Mainline compressor plants and two Alberta System compressor plants was carried out in 2005. TransCanada will continue to actively invest in improved environmental protection measures.

For information on management of risks with respect to the Gas Transmission business, see the "Risk Management" section.

## GAS TRANSMISSION – OUTLOOK

As demand for natural gas continues to grow across North America, TransCanada's Gas Transmission business will continue to play a critical role in the reliable transportation of natural gas. For 2006, the business will focus on the reliable delivery of natural gas to growing markets, connecting new supply and progressing development of new infrastructure to connect northern gas. TransCanada will also focus on development of the Keystone pipeline.

Looking forward, it is expected that producers will continue to explore and develop new fields, particularly in northeastern B.C. and the west central foothills regions of Alberta, as well as unconventional supply such as gas production from CBM reserves. New facilities will be required to move this incremental supply based on the location of the resource, even though overall WCSB supply is expected to remain essentially flat. The Alberta System anticipates filing an application during 2006 with the EUB, to construct new facilities required to connect additional natural gas supplies anticipated to be delivered to the Alberta System from the Mackenzie Delta.

In 2006, TransCanada will continue to focus on serving the growing demand in the Fort McMurray area with construction of new natural gas transmission facilities, beginning in late 2006, with a contractual on-stream date of April 1, 2007. In 2008 and 2009, TransCanada anticipates constructing additional facilities as the Fort McMurray oil sands demand for natural gas continues to grow.

It is expected that incremental supply from LNG will serve growing North American markets in the mid to long term. As a result, TransCanada will take prudent steps to further evaluate the potential commercial and operational implications of connecting LNG facilities to those systems affected.

Prior to the onset of new supply from LNG and northern gas, many of the markets served by TransCanada's systems may be exposed to volatile natural gas prices. As a result, TransCanada will continue to focus on operational excellence and collaborative efforts with all stakeholders on negotiated settlements and service options that will increase the value of TransCanada's business to customers and shareholders.

*Earnings*

TransCanada's earnings from its Canadian wholly-owned pipelines are primarily determined by the average investment base, ROE, deemed common equity and opportunity for incentive earnings. In the short to medium term, the company expects a modest level of investment in these mature assets and therefore anticipates a continued net decline in the average investment base due to depreciation expense in excess of capital expenditures. Accordingly, without an increase in ROE, deemed common equity or incentive opportunities, future earnings are anticipated to decrease. However, these mature assets will continue to generate strong cash flows that can be redeployed to other projects offering higher returns. Under the current regulatory model, earnings from the Canadian wholly-owned pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

In December 2005, the NEB established the 2006 ROE for the Canadian Mainline at 8.88 per cent compared to 9.46 per cent in 2005. In addition, the 2006 average investment base is expected to continue to decline. These two factors are expected to lower earnings on the Canadian Mainline in 2006 relative to 2005 if there are no offsetting factors. TransCanada is currently engaged in settlement discussions with its stakeholders on matters related to the Canadian Mainline's 2006 tolls.

Alberta System earnings in 2006 will be negatively influenced by the decrease in the EUB's generic ROE to 8.93 per cent in 2006 from 9.50 per cent in 2005, and an anticipated decrease in the average investment base. The three year revenue requirement settlement reached in 2005 does provide the opportunity for limited incentive earnings as the settlement contains some at-risk cost components. If TransCanada is successful in its focus on cost efficiency, there is an opportunity to partially mitigate the effect of a lower ROE and average investment base for the Alberta System in 2006.

In 2006, earnings from Portland and the Gas Transmission Northwest System may be negatively impacted should Calpine contracts be rejected on the respective systems. Calpine's FT contract accounts for approximately 24 per cent of Portland's total FT revenues. On the Gas Transmission Northwest System, approximately seven per cent of transportation revenues come from Calpine's FT contracts. It is not possible at this time to determine the impact of any potential mitigating factors on 2006 earnings if these contracts are rejected.

Reduced firm contract volumes on the Gas Transmission Northwest System, including the effects of customer bankruptcies, are expected to have a slightly negative impact on the Gas Transmission Northwest System results compared to 2005. The impact of the 2006 rate case filing on the system's results in 2006 is uncertain at this time.

Anticipated lower firm service revenues on certain partially-owned pipelines and a full year of reduced ownership of PipeLines LP are expected to be partially offset by the effects of a higher deemed equity structure on the Foothills System and BC System and the expected growth in natural gas storage net earnings.

*Capital Expenditures*

Total capital spending for the Wholly-Owned Pipelines during 2005 was $135 million. Overall capital spending on the Wholly-Owned Pipelines in 2006 is expected to be approximately $382 million. Capital expenditures on the Edson natural gas storage project and the Tamazunchale Pipeline are expected to be approximately $105 million and $95 million, respectively, in 2006.

**NATURAL GAS THROUGHPUT VOLUMES**
*(Bcf)*[(1)]

| | **2005** | 2004 | 2003 |
|---|---|---|---|
| Canadian Mainline[(2)] | **2,997** | 2,621 | 2,628 |
| Alberta System[(3)] | **3,999** | 3,909 | 3,883 |
| Gas Transmission Northwest System[(4)] | **777** | 181 | |
| Foothills System | **1,051** | 1,139 | 1,110 |
| BC System | **321** | 360 | 325 |
| North Baja System[(4)] | **84** | 13 | |
| Great Lakes | **850** | 801 | 856 |
| Northern Border | **808** | 845 | 850 |
| Iroquois | **394** | 356 | 341 |
| TQM | **166** | 159 | 164 |
| Ventures LP | **192** | 136 | 111 |
| Portland | **62** | 50 | 53 |
| Tuscarora | **25** | 25 | 22 |
| TransGas | **19** | 18 | 16 |

(1) Billion cubic feet.

(2) Canadian Mainline deliveries originating at the Alberta border and in Saskatchewan for the year ended December 31, 2005 were 2,215 Bcf (2004 – 2,017 Bcf; 2003 – 2,055 Bcf).

(3) Field receipt volumes for the Alberta System for the year ended December 31, 2005 were 4,034 Bcf (2004 – 3,952 Bcf; 2003 – 3,892 Bcf).

(4) TransCanada acquired the Gas Transmission Northwest System and the North Baja System on November 1, 2004. The volumes for 2004 represent November and December 2004 throughput.

## POWER

### HIGHLIGHTS

*Net Earnings*

- Power's net earnings in 2005 were $561 million compared to $396 million in 2004.
- Excluding gains related to Power LP and Paiton Energy, Power's net earnings for 2005 increased $44 million to $253 million compared to $209 million in 2004.
- TransCanada's operating and other income before income taxes from Bruce Power for 2005 of $195 million increased by $65 million compared to $130 million in 2004.

*Expanding Asset Base*

- In October 2005, Bruce Power and the OPA completed a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. Restarting Units 1 and 2, which have a capacity of approximately 1,500 MW, will boost Bruce Power's output to more than 6,200 MW of which approximately 2,450 MW is TransCanada's share. As at December 31, 2005, TransCanada owned 47.9 per cent of Bruce A and 31.6 per cent of Bruce B.
- Effective December 31, 2005, TransCanada acquired the remaining rights and obligations of the 756 MW Sheerness PPA from the Alberta Balancing Pool for $585 million. The remaining term of the PPA is approximately 15 years. The plant consists of two coal-fired thermal power generating units.
- In April 2005, TransCanada acquired the hydroelectric generation assets from USGen with a total generating capacity of 567 MW for US$503 million.
- In January 2005, the 90 MW Grandview natural gas-fired cogeneration plant located in Saint John, New Brunswick was commissioned and placed in service.
- Construction continued on the 550 MW Bécancour cogeneration plant and it is expected to be in service in late 2006.
- The 739.5 MW Cartier Wind project awarded construction contracts in 2005. Construction on the first two projects is expected to commence early 2006 and the first project is scheduled to be commissioned in late 2006.

*Plant Availability*

- Weighted average plant availability was 87 per cent in 2005, excluding Bruce Power, compared to 96 per cent in 2004.
- Including Bruce Power, weighted average plant availability was 84 per cent in 2005, compared to 90 per cent in 2004.

**Power Generation**

1. Bear Creek
2. MacKay River
3. Redwater
4. Sundance A PPA
5. Sundance B PPA (50% ownership)
6. Sheerness PPA
7. Carseland
8. Cancarb
9. Bruce Power
   (Bruce A – 47.9%, Bruce B – 31.6%)
10. OSP
11. Bécancour (under construction)
12. Cartier Wind
    (62% ownership, under construction)
13. Grandview
14. TC Hydro


**BEAR CREEK** An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

**MACKAY RIVER** A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

**REDWATER** A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

**SUNDANCE A&B** The Sundance power facility in Alberta is the largest coal-fired electrical generating facility in Western Canada. TransCanada owns the 560 MW Sundance A PPA, ending in 2017. TransCanada effectively owns 50 per cent of the 706 MW Sundance B PPA, ending in 2020.

**SHEERNESS** In December 2005, TransCanada acquired the remaining rights and obligations of the 756 MW Sheerness PPA with a remaining term of 15 years. The plant consists of two coal-fired thermal power generating units.

**CARSELAND** An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

**CANCARB** The 27 MW Cancarb facility at Medicine Hat, Alberta is fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

**BRUCE POWER** At December 31, 2005, TransCanada owned 31.6 per cent of Bruce B, consisting of operating Units 5 to 8 with approximately 3,200 MW of generating capacity. In addition, TransCanada owned 47.9 per cent of Bruce A, consisting of operating Units 3 and 4 with approximately 1,500 MW of generating capacity and currently idle Units 1 and 2 with approximately 1,500 MW of generating capacity. Units 1 and 2 are currently being refurbished for expected restart of the first unit commencing in 2009.

**OSP** The OSP plant is a 560 MW natural gas-fired, combined-cycle facility in Rhode Island.

**BÉCANCOUR** The 550 MW Bécancour natural gas-fired cogeneration power plant located near Trois-Rivières, Québec is under construction and is expected to be in service in late 2006. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract. Steam will also be sold to local businesses.

**CARTIER WIND** Cartier Wind, 62 per cent owned by TransCanada, is comprised of six wind projects totalling 739.5 MW to be commissioned between 2006 and 2012. Construction on the first two projects, with a combined generating capacity of 210 MW, is expected to commence early 2006 and the first project is expected to be in service in late 2006. The entire power output will be supplied to Hydro-Québec under a 20 year power purchase contract.

**GRANDVIEW** A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick was commissioned and in service in January 2005. Under a 20 year tolling arrangement, 100 per cent of the plant's heat and electricity output is sold to Irving.

**TC HYDRO** In April 2005, TransCanada closed the acquisition of hydroelectric generation assets from USGen. These merchant assets have a total generating capacity of 567 MW and are located in New Hampshire, Vermont and Massachusetts.

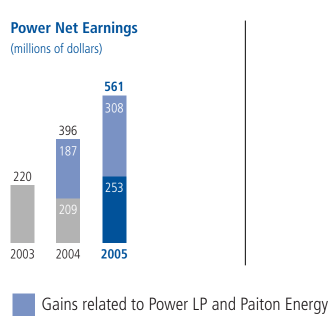
**POWER RESULTS-AT-A-GLANCE**
*Year ended December 31 (millions of dollars)*

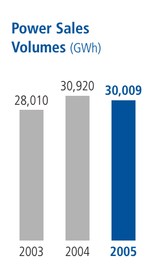
| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Bruce Power | **195** | 130 | 99 |
| Western operations | **123** | 138 | 160 |
| Eastern operations | **137** | 108 | 127 |
| Power LP investment | **29** | 29 | 35 |
| General, administrative, support costs and other | **(102)** | (89) | (86) |
| Operating and other income | **382** | 316 | 335 |
| Financial charges | **(11)** | (13) | (12) |
| Income taxes | **(118)** | (94) | (103) |
| | **253** | 209 | 220 |
| Gains related to Power LP and Paiton Energy (after tax) | **308** | 187 | – |
| Net earnings | **561** | 396 | 220 |

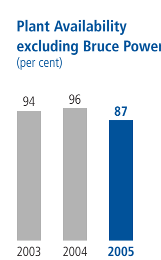
Power's net earnings in 2005 of $561 million increased $165 million compared to $396 million in 2004 primarily due to gains related to Paiton Energy and Power LP. In 2005, TransCanada sold its approximate 11 per cent interest in Paiton Energy to subsidiaries of The Tokyo Electric Power Company for gross proceeds of US$103 million ($122 million) resulting in an after-tax gain of $115 million. In August 2005, TransCanada sold its ownership interest in Power LP to EPCOR Utilities Inc. (EPCOR) for net proceeds of $523 million resulting in an after-tax gain of $193 million. Included in 2004 net earnings was an after-tax gain of $187 million comprised of a $15 million after-tax gain on the sale of TransCanada's Curtis Palmer and ManChief power facilities to Power LP as well as $172 million of after-tax dilution and other gains.

Excluding the Paiton Energy and Power LP-related gains in 2005 and 2004, respectively, Power's net earnings for the year ended December 31, 2005 of $253 million increased $44 million compared to $209 million in 2004. The increase was primarily due to higher operating and other income from Bruce Power and Eastern Operations, partially offset by a reduced contribution from Western Operations and higher general, administrative, support costs and other.

In 2003, Western Operations' results included a $31 million pre-tax ($19 million after tax) settlement with a former counterparty that defaulted in 2001 under power forward contracts. Power's net earnings for 2004, excluding gains related to Power LP in 2004 and the counterparty settlement in 2003, increased $8 million year-over-year. Pre-tax equity income from Bruce Power of $130 million in 2004 increased $31 million compared to TransCanada's period of ownership in 2003. This was partially offset by lower contributions from Eastern Operations and Power LP investment.



### POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

| | MW | Fuel Type |
|---|---|---|
| **Bruce Power**(1) | 2,450 | Nuclear |
| **Western operations** | | |
| Sheerness(2) | 756 | Coal |
| Sundance A(3) | 560 | Coal |
| Sundance B(3) | 353 | Coal |
| MacKay River | 165 | Natural gas |
| Carseland | 80 | Natural gas |
| Bear Creek | 80 | Natural gas |
| Redwater | 40 | Natural gas |
| Cancarb | 27 | Natural gas |
| | 2,061 | |
| **Eastern operations** | | |
| TC Hydro(4) | 567 | Hydro |
| OSP | 560 | Natural gas |
| Bécancour(5) | 550 | Natural gas |
| Cartier Wind(6) | 458 | Wind |
| Grandview(7) | 90 | Natural gas |
| | 2,225 | |
| Total Nominal Generating Capacity | 6,736 | |

(1) Represents TransCanada's 47.9 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B at December 31, 2005. Bruce A consists of four 750 MW reactors. Bruce A Unit 4 was returned to service in fourth quarter 2003. Bruce A Unit 3 was returned to service in first quarter 2004. Bruce A Units 1 and 2 are currently being refurbished and are expected to restart commencing in 2009. Bruce B consists of four reactors which are currently in operation, with a combined capacity of approximately 3,200 MW.

(2) TransCanada directly acquires 756 MW from Sheerness through a long-term PPA acquired in December 2005.

(3) TransCanada directly or indirectly acquires 560 MW from Sundance A and 353 MW from Sundance B through long-term PPAs, which represents 100 per cent of the Sundance A and 50 per cent of the Sundance B power plant output, respectively.

(4) Acquired in April 2005.

(5) Currently under construction.

(6) Currently under construction. Represents TransCanada's 62 per cent of 739.5 MW.

(7) Placed in-service in January 2005.

## POWER – FINANCIAL ANALYSIS

### Bruce Power

On October 31, 2005, Bruce Power and the OPA completed a long-term agreement whereby Bruce A will restart and refurbish the currently idle Units 1 and 2, extend the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replace the steam generators on Unit 4. As a result of the agreement between Bruce Power and the OPA, and Cameco's decision not to participate in the restart and refurbishment program, a new partnership was created. Bruce A subleases its facilities, which are comprised of Units 1 to 4, from Bruce B. TransCanada and BPC each incurred a net cash outlay of approximately $100 million on the formation of Bruce A. As at December 31, 2005, TransCanada and BPC each owned a 47.9 per cent interest in Bruce A. The remaining 4.2 per cent is owned by the Power Worker's Union Trust No. 1 and The Society of Energy Professionals Trust. The day-to-day operations of the Bruce Power facilities are expected to be unaffected by the formation of Bruce A and TransCanada continues to own 31.6 per cent of the Bruce B Units 5 to 8.

Upon reorganizing, both Bruce A and Bruce B became jointly controlled entities and TransCanada proportionately consolidated these investments on a prospective basis from October 31, 2005. The following Bruce Power financial results reflect the operations of the full six-unit operation for all periods. The Bruce Power information below includes adjustments to eliminate the effect of certain intercompany transactions between Bruce A and Bruce B.

**Bruce Power Results-at-a-Glance**
*Year ended December 31 (millions of dollars)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Bruce Power (100 per cent basis)** | | | |
| Revenues | | | |
| Power | **1,907** | 1,563 | 1,183 |
| Other[1] | **35** | 20 | 25 |
| | **1,942** | 1,583 | 1,208 |
| Operating expenses | | | |
| Operations and maintenance | **(871)** | (793) | (608) |
| Fuel | **(77)** | (68) | (45) |
| Supplemental rent | **(164)** | (156) | (111) |
| Depreciation and amortization | **(198)** | (161) | (89) |
| | **(1,310)** | (1,178) | (853) |
| Operating income | **632** | 405 | 355 |
| Financial charges under equity accounting – to October 31, 2005 | **(58)** | (67) | (69) |
| | **574** | 338 | 286 |
| TransCanada's proportionate share | **188** | 107 | 65 |
| Adjustments | **7** | 23 | 34 |
| TransCanada's operating and other income from Bruce Power[2] | **195** | 130 | 99 |
| **Bruce Power – Other Information** | | | |
| Plant availability | **80%** | 82% | 83% |
| Sales volumes (GWh)[3] | | | |
| Bruce Power – 100 per cent | **32,900** | 33,600 | 21,060 |
| TransCanada's proportionate share | **10,732** | 10,608 | 6,655 |
| Results per MWh[4] | | | |
| Power revenues | **$58** | $47 | $48 |
| Fuel | **$2** | $2 | $2 |
| Total operating expenses[5] | **$40** | $35 | $36 |
| Percentage of output sold to spot market | **49%** | 52% | 35% |

(1) Includes fuel cost recoveries for Bruce A of $4 million for 2005.

(2) TransCanada's consolidated equity income includes $168 million which represents TransCanada's 31.6 per cent share of Bruce Power earnings for the ten months ended October 31, 2005. TransCanada acquired a 31.6 per cent interest in Bruce B in February 2003, which

at the time owned the currently idle Bruce A Units 1 and 2 as well as the currently operating Bruce A Units 3 and 4 and Bruce B Units 5 to 8.

(3) Gigawatt hours.

(4) Megawatt hours.

(5) Net of cost recoveries.

TransCanada's operating and other income from its combined investment in Bruce Power for 2005 was $195 million compared to $130 million for 2004. The increase of $65 million was primarily due to higher realized prices in 2005 and was offset in part by higher maintenance costs, higher depreciation and lower capitalization of labour and other in-house costs following the restart of Unit 3 in first quarter 2004. Adjustments to TransCanada's combined interest in Bruce Power's income before income taxes for 2005 were lower than in 2004 primarily due to a lower amortization of the purchase price allocated to the fair value of sales contracts in place at the time of acquisition in 2003.

Combined Bruce Power prices achieved during 2005 (excluding Bruce cost recoveries) were $58 per MWh compared to $47 per MWh in 2004 reflecting higher prices on uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of cost recoveries) increased to $40 per MWh for 2005 from $35 per MWh in 2004. This was primarily the result of one additional planned maintenance outage in 2005 compared to 2004 as well as higher maintenance costs, higher depreciation and lower capitalization of labour and other in-house costs following the restart of Unit 3.

The Bruce units ran at a combined average availability of 80 per cent in 2005, compared to an 82 per cent average availability during 2004. The lower availability in 2005 was the result of 67 additional days of planned maintenance outages plus an additional 45 forced outage days in 2005 as compared to 2004. The additional forced outage days in 2005 are due in large part to a 27 day forced outage that occurred as a result of a transformer fire at Unit 6.

TransCanada's operating and other income from its combined investment in Bruce Power for 2004 was $130 million compared to $99 million for 2003. This increase was primarily due to higher output in 2004 as a result of the return to service of Units 3 and 4 as well as a full year of earnings in 2004 on Units 5 to 8 compared to earnings from February 14 to December 31 in 2003, reflecting TransCanada's period of ownership in 2003. Adjustments to TransCanada's interest in Bruce Power income before taxes for 2004 were lower than the same period in 2003 primarily due to the cessation of interest capitalization upon the return to service of Units 3 and 4.

Income from Bruce B is directly impacted by fluctuations in wholesale spot market prices for electricity and income from both Bruce A and Bruce B units is impacted by overall plant availability, which in turn, is impacted by scheduled and unscheduled maintenance. To reduce its exposure to spot market prices, Bruce B had, as at December 31, 2005, entered into fixed price sales contracts to sell forward approximately 13,000 GWh hours of 2006 output and approximately 3,600 GWh of 2007 output. As a result of the contract with the OPA, all of the output from Bruce A will be sold at a fixed price of $57.37 per MWh, adjusted annually on April 1 for inflation, before recovery of fuel costs from the OPA. Under the terms of the arrangement between Bruce A and the OPA, effective October 31, 2005, Bruce A receives a contract price for power generated, where the price is adjusted for inflation annually on April 1 and capital cost variances associated with the restart and refurbishment project but will not vary with changes in the wholesale price of power in the Ontario market. As part of this contract, sales from the Bruce B Units 5 to 8 are subject to a floor price of $45 per MWh, adjusted annually for inflation on April 1. Receipts by Bruce Power under this floor price mechanism are refundable if prices subsequently increase above the floor price.

The overall plant availability percentage in 2006 is expected to be in the low 90s for the four Bruce B units and the low 80s for the two operating Bruce A units. A planned outage on Bruce A Unit 3 is scheduled to last approximately one month during first quarter 2006 and a two month maintenance outage of Bruce A Unit 4 is expected to commence in second quarter 2006. The only planned maintenance outage for 2006 for Bruce B is an approximate two month outage scheduled for Unit 8 beginning in third quarter 2006.

In 2005, cash distributions to partners, excluding a special distribution, were $400 million of which TransCanada's share was $126 million. No distributions were made to partners in 2004. The partners have agreed that all excess cash from both Bruce A and Bruce B will be distributed on a monthly basis and that separate cash calls will be made for major capital projects, including the Bruce A restart and refurbishment project.

Bruce A's capital program for the restart and refurbishment project is expected to total approximately $4.25 billion and TransCanada's approximate $2.125 billion share will be financed through capital contributions to 2011. A capital cost risk and reward sharing schedule with OPA is in place for spending below or in excess of the $4.25 billion base case estimate. Work to refurbish Units 1 and 2 has commenced with the first unit expected to be online in 2009, subject to approval by the Canadian Nuclear Safety Commission. Restarting Units 1 and 2, which have a combined capacity of approximately 1,500 MW, will boost the Bruce facilities' overall output to more than 6,200 MW. As at December 31, 2005, Bruce A had capitalized $324 million with respect to the restart and refurbishment project.

## Western Operations

**Western Operations Results-at-a-Glance**[(1)]
*Year ended December 31 (millions of dollars)*

| | **2005** | 2004 | 2003 |
|---|---|---|---|
| Revenues | | | |
| Power | **715** | 606 | 688 |
| Other[(2)] | **158** | 120 | 112 |
| | **873** | 726 | 800 |
| Cost of sales | | | |
| Power | **(476)** | (377) | (442) |
| Other[(3)] | **(104)** | (64) | (71) |
| | **(580)** | (441) | (513) |
| Other costs and expenses | **(149)** | (125) | (98) |
| Depreciation | **(21)** | (22) | (29) |
| Operating and other income | **123** | 138 | 160 |

(1) ManChief is included until April 30, 2004.

(2) Includes Cancarb Thermax and natural gas sales.

(3) Includes the cost of natural gas sold.

**Western Operations Sales Volumes**[1]
*Year ended December 31 (GWh)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Supply** | | | |
| Generation | **2,245** | 2,105 | 2,010 |
| Purchased | | | |
| Sundance A & B PPAs | **6,974** | 6,842 | 6,959 |
| Other purchases | **2,687** | 2,748 | 3,327 |
| | **11,906** | 11,695 | 12,296 |
| **Contracted vs. Spot** | | | |
| Contracted | **10,374** | 10,705 | 11,039 |
| Spot | **1,532** | 990 | 1,257 |
| | **11,906** | 11,695 | 12,296 |

(1) ManChief is included until April 30, 2004.

As at December 31, 2005, Western Operations directly controlled approximately 2,100 MW of power supply in Alberta from its three long-term PPAs and five natural gas-fired cogeneration facilities. The Western Operations power supply portfolio is now comprised of approximately 1,700 MW of low-cost, base-load coal-fired generation supply and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio is among the lowest-cost, most competitive generation in the Alberta market area. The three long-term PPAs include the December 2005 acquisition of the remaining rights and obligations of the 756 MW Sheerness PPA in addition to the Sundance A and Sundance B PPAs acquired in 2001 and 2002, respectively. The Sheerness PPA was acquired from the Alberta Balancing Pool for $585 million and has a remaining term of approximately 15 years. The PPAs entitle TransCanada to the output capacity of these coal facilities, ending in 2017 to 2020.

The focus of Western Operations is to maximize the value of its power supply portfolio through a balanced portfolio of long- and short-term power sale contracts. The focus is also on expanding its power supply portfolio though acquisitions and optimizing the value and output from its existing generation assets. The success of Western Operations is the direct result of its two integrated functions – marketing and plant operations.

The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced from the PPAs, markets uncommitted generation volumes from the cogeneration facilities and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Power's return from its portfolio of power supply and managing risks around uncontracted volumes. The intention for the Sheerness output is the same as the Sundance output, whereby a significant portion of the power supply is expected to be sold under long-term contract to the extent possible in the market. The majority of the expected output from the cogeneration plants is also sold under long-term contract. Some portion of power supply from the PPAs and the cogeneration assets is intentionally not committed under long-term sales contracts to assist in managing Power's overall portfolio of generation. This approach to portfolio management assists in minimizing costs in situations where Power would otherwise have to purchase power in the open market to fulfill its contractual obligations. In 2005, approximately 13 per cent of power sales volumes were sold into the spot market. To reduce exposure to spot market prices of uncontracted volumes, as at December 31, 2005, Western Operations had fixed price sale contracts to sell forward approximately 9,800 GWh for 2006 and 6,000 GWh for 2007.

Plant operations consist of five natural gas-fired cogeneration power plants located in Alberta with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A majority of the expected output is sold under long-term contracts and the remainder is subject to fluctuations in the price of power and natural gas. Market heat rates in Alberta in 2005 were at historic lows earlier in the year but improved substantially by year-end. Market heat rate is determined by dividing the average price of power per MWh by the average price of natural gas per gigajoule (GJ) for a given period. To the extent power is not sold under long-term contract and plant fuel-gas has not been purchased, the higher the market heat rate, the more profitable is a natural gas-fired generating facility. Market heat rates averaged approximately 8.3 GJ/MWh in 2005 compared to approximately 8.8 GJ/MWh in 2004. All plants, except the 80 MW Bear Creek facility located near Grand Prairie, operated with an average plant availability in 2005 of approximately 93 per cent.

Bear Creek experienced an unplanned outage in 2005 resulting from technical difficulties with its gas turbine in the early part of 2005 and the facility has remained on an unplanned outage since May 31, 2005. Technical evaluation continued throughout 2005 regarding a possible long-term solution and the asset is expected to be back in service by mid-2006.

Operating and other income for 2005 was $123 million or $15 million lower compared to $138 million earned in 2004. This decrease was primarily due to reduced margins in 2005 resulting from the lower market heat rates on uncontracted volumes of power generated, fee revenues earned in 2004 from Power LP and a lower contribution from Bear Creek. Revenues and cost of sales increased in 2005 compared to 2004 primarily due to higher realized prices. Other costs and expenses, which include fuel gas consumed in generation, increased due to higher operating and fuel usage costs at MacKay River resulting from a full year of operation and higher natural gas prices. Generation volumes in 2005 increased compared to 2004 primarily due to a full year of operations at MacKay River partially offset by the unplanned outage at Bear Creek. The potential to earn fees to manage and operate Power LP's plants was eliminated with the sale of Power LP to EPCOR in August 2005. In 2005, approximately 13 per cent of power sales volumes were sold into the spot market compared to eight per cent in 2004.

Operating and other income in 2004 of $138 million was $22 million lower than the $160 million earned in 2003. The decrease was mainly due to a positive $31 million pre-tax settlement in June 2003 with a former counterparty that defaulted in 2001 under power forward contracts, as well as reduced income from ManChief following the sale of the plant to Power LP in April 2004. Partially offsetting these decreases were contributions from the MacKay River plant which was placed in service in 2004, fees earned with respect to Power LP's asset acquisitions in 2004 and the impact of higher net margins achieved in second and third quarter 2004 on the overall portfolio.

## Eastern Operations

**Eastern Operations Results-at-a-Glance**[1]
*Year ended December 31 (millions of dollars)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Revenues | | | |
| Power | **505** | 535 | 608 |
| Other[2] | **412** | 238 | 200 |
| | **917** | 773 | 808 |
| Cost of sales | | | |
| Power | **(215)** | (288) | (281) |
| Other[2] | **(373)** | (211) | (185) |
| | **(588)** | (499) | (466) |
| Other costs and expenses | **(167)** | (146) | (186) |
| Depreciation | **(25)** | (20) | (29) |
| Operating and other income | **137** | 108 | 127 |

(1) Curtis Palmer is included until April 30, 2004.

(2) Other includes natural gas.

**Eastern Operations Sales Volumes**[1]
*Year ended December 31 (GWh)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Supply** | | | |
| Generation | **2,879** | 1,467 | 1,871 |
| Purchased | **2,627** | 4,731 | 5,035 |
| | **5,506** | 6,198 | 6,906 |
| **Contracted vs. Spot** | | | |
| Contracted | **4,919** | 6,055 | 6,678 |
| Spot | **587** | 143 | 228 |
| | **5,506** | 6,198 | 6,906 |

(1) Curtis Palmer is included until April 30, 2004.

Eastern Operations conducts its business primarily in the Northeastern U.S. and Eastern Canada markets and excludes Bruce Power. In the New England market, Eastern Operations has established a successful marketing operation and, in 2005, acquired a significant group of hydroelectric generation assets from USGen with generation capacity of 567 MW. In Eastern Canada, construction continued on the 550 MW Bécancour natural gas-fired plant in Québec and the 90 MW Grandview cogeneration facility was placed into service on January 1, 2005. In late 2005, development plans were finalized and construction is expected to commence early 2006 on the first two of six wind farm projects, with generating capacity of 210 MW of the 739.5 MW Cartier Wind projects in Québec. Including facilities that are under construction or in development, Eastern Operations owns more than 2,200 MW of power generation capacity.

Eastern Operations' success in the New England deregulated power markets is the direct result of a knowledgeable, region-specific marketing operation which is conducted through its wholly-owned subsidiary, TransCanada Power Marketing Limited (TCPM), located in Westborough, Massachusetts. TCPM has firmly established itself as a leading energy provider and marketer and is focused on selling power under short- and long-term contracts to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from both its own generation and wholesale power purchases. To reduce its exposure to spot market prices, as at December 31, 2005, Eastern Operations had entered into fixed price sales contracts to sell approximately 5,000 GWh of power for 2006 and approximately 3,500 GWh of power for 2007, although certain contracted volumes are dependent on customer usage levels. TCPM is a full requirement electricity service provider offering varied products and services to assist customers in managing their power supply and power prices in volatile deregulated power markets.

Eastern Operations' operating power generation assets currently consist of TC Hydro, Ocean State Power (OSP) and Grandview.

The TC Hydro assets, acquired on April 1, 2005, include 13 hydroelectric stations housing 39 generating units on the Connecticut River System in New Hampshire and Vermont, and the Deerfield River System in Massachusetts and Vermont. These facilities were integrated into TransCanada in 2005. Water flows in 2005 through the hydro assets were above the long-term average as a result of higher precipitation in the areas surrounding the river systems.

OSP is a 560 MW natural gas-fired plant located in Rhode Island. In 2005, OSP was successful in restructuring its long-term natural gas fuel supply contracts with its suppliers. The contract restructuring at OSP reduced the term of the long-term natural gas supply contracts by approximately three years (currently ending in October 2008) and adjusted the pricing to track spot market pricing of natural gas at the Niagara delivery point versus the previously arbitrated pricing that had resulted in an above-market cost of natural gas for OSP. The new contracts, for approximately 100,000 GJ per day, require OSP to take delivery of the natural gas irrespective of the fuel requirements at the plant. OSP experienced an unplanned outage for most of the first half of 2005 resulting from a failure of one of the steam turbines at the plant. This unit was returned to service in mid-2005; however, due to the nature of the failure, the second steam turbine at OSP was taken out of service to undertake repairs and was returned to service in January 2006. An insurance claim has been filed in respect of this incident, including a claim for business interruption coverage. This claim is currently under discussion with the insurers.

Grandview is a 90 MW natural gas-fired cogeneration facility on the site of the Irving refinery in Saint John, New Brunswick. The Grandview facility was commissioned in January 2005. Under a 20 year tolling arrangement, Irving supplies fuel for the plant and contracts for 100 per cent of the plant's heat and electricity output.

Eastern Operations emerging presence in Eastern Canada is represented by the development and construction in 2006 of the 550 MW natural gas-fired Bécancour plant and the first two of six wind farms of the Cartier Wind project. The first of the two wind farms is expected to be in service in late 2006. Bécancour is expected to be operational in late 2006. Bécancour and Cartier Wind are located in Québec.

Operating and other income for 2005 was $137 million or $29 million higher than the $108 million earned in 2004. Incremental income from the acquisition of the TC Hydro assets and income from the Grandview cogeneration facility were the primary reasons for this increase. Partially offsetting these increases were a $16 million pre-tax ($10 million after tax) contract restructuring payment made by OSP to its natural gas fuel suppliers in first quarter 2005, a $16 million pre-tax ($10 million after tax) reduction in income as a result of the sale of Curtis Palmer to Power LP in April 2004, and a loss of operating income primarily associated with the expiration of certain long-term sales contracts in 2004.

Eastern Operations' power revenues decreased in 2005 primarily due to lower long-term sales volumes resulting from the expiration of certain contracts at the end of 2004. Partially offsetting this were higher realized prices in 2005. Other revenue and other cost of sales increased year-over-year as a result of natural gas purchased and resold under the new natural gas supply contracts at OSP. Cost of sales for power were lower in 2005 due to the impact of lower purchased volumes partially offset by higher prices for purchased power. Purchased power volumes were lower in 2005 due to lower contracted sales volumes and the incremental power generation from the purchase of the TC Hydro assets. Volumes generated from the TC Hydro assets reduced the requirement to purchase power to fulfill contractual sales obligations. Other costs and expenses in 2005 were higher primarily due to the acquisition of the TC Hydro assets.

Operating and other income for 2004 was $108 million or $19 million lower than the $127 million earned in 2003. This decrease was mainly due to a reduction in income as a result of the sale of the Curtis Palmer hydroelectric facilities to Power LP in April 2004, the unfavourable impact of higher natural gas fuel costs at OSP and a weaker U.S. dollar in 2004. Partially offsetting these decreases was a $16 million positive impact from the restructuring transaction related to the power purchase contracts in 2004 between OSP and Boston Edison Company (Boston Edison). TransCanada recognized earnings from the transaction's effective date of April 1, 2004.

### Power LP Investment

On August 31, 2005, TransCanada closed the sale of all of its interest in Power LP to EPCOR for net proceeds of $523 million resulting in an after-tax gain of $193 million. This divestiture included approximately 14.5 million Partnership units, representing approximately 30.6 per cent of the outstanding units, 100 per cent ownership of the general partner of Power LP, and management and operations agreements governing the ongoing operation of Power LP's generation assets. TransCanada's investment in Power LP generated operating and other income of $29 million in 2005 compared to $29 million and $35 million in 2004 and 2003, respectively.

**Weighted Average Plant Availability**[1]

| | **2005** | 2004 | 2003 |
|---|---|---|---|
| Bruce Power[2] | **80%** | 82% | 83% |
| Western operations[3] | **85%** | 95% | 93% |
| Eastern operations[3][4] | **83%** | 95% | 94% |
| Power LP investment[3][5] | **94%** | 97% | 96% |
| All plants, excluding Bruce Power | **87%** | 96% | 94% |
| All plants | **84%** | 90% | 90% |

(1) Plant availability represents the percentage of time in the year that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages.

(2) Unit 3 is included effective March 1, 2004 and Unit 4 is included effective November 1, 2003.

(3) ManChief and Curtis Palmer are included in Power LP Investment effective April 30, 2004.

(4) TC Hydro is included in Eastern Operations effective April 1, 2005.

(5) Power LP is included to August 31, 2005.

Weighted average plant availability, excluding Bruce Power, was 87 per cent in 2005 compared to 96 per cent in 2004. Western Operations' weighted average plant availability was impacted in 2005 by an unplanned outage at Bear Creek and a planned outage at MacKay River. In 2005, Eastern Operations experienced two significant outages at OSP. The first outage was completed in mid-2005 and the second outage was completed in January 2006.

## POWER – OPPORTUNITIES AND DEVELOPMENTS

TransCanada is committed to growing the Power business through acquisitions and development of greenfield opportunities in markets it knows and where it has a competitive advantage – primarily Western Canada, Eastern Canada and the Northeastern U.S. The North American power industry is expansive and will provide many opportunities for greenfield growth in power generation and power infrastructure projects. In addition to greenfield growth opportunities, TransCanada will continue to pursue acquisitions of additional power assets, including opportunities resulting from, amongst other things, industry and corporate restructurings and corporate bankruptcies. Power's diverse power supply portfolio will continue to include low-cost, base-load facilities with low operating costs and high reliability and/or be underpinned by secure long-term contracts.

The Cartier Wind project is scheduled to commercially place in service the first of six wind farms in 2006. The remaining five wind farms are expected to be placed in service between 2007 and 2012. The Bécancour natural gas-fired cogeneration power plant is expected to be in service in late 2006. Bruce Power will continue refurbishment of the currently idle Bruce A Units 1 and 2 for expected restart commencing in 2009.

In February 2006, the Ontario Energy Minister directed the OPA to move forward to negotiate the terms for the construction of the 550 MW Portlands Energy Centre (PEC) in downtown Toronto. TransCanada has a 50 per cent interest in PEC through a partnership with Ontario Power Generation.

## POWER – BUSINESS RISKS

*Plant Availability*
Maintaining plant availability is critical to the continued success of the Power business and this risk is mitigated through a commitment to an operational excellence model that provides low-cost, reliable operating performance at each of the company's power plants. This same commitment to operational excellence will be applied in 2006 and future years. However, unexpected plant outages and/or the duration of outages could result in lower sales revenue, reduced margins, increased maintenance costs and may require power purchases at market prices to enable TransCanada to meet the company's contractual power supply obligations.

*Fluctuating Market Prices*
TransCanada operates in highly competitive, deregulated power markets. Volatility in electricity prices is caused by market factors such as power plant fuel costs, fluctuating supply and demand which are greatly affected by weather, power consumption and plant availability. TransCanada manages these inherent market risks through:

- long-term purchase and sales contracts for both electricity and plant fuels;
- control of generation output;
- matching physical plant contracts or PPA supply with customer demand;
- fee-for-service managed accounts rather than direct commodity exposure; and
- the company's overall risk management program with respect to general market and counterparty risks.

The company's risk management practices are described further in the section on "Risk Management". See the section below "Power – Business Risks – Uncontracted Volumes".

*Weather*

Extreme temperature and weather events often affect power and natural gas demand and create price volatility, and may also impact the ability to transmit power to markets. Seasonal changes in temperature also affect the efficiency and output capability of natural gas-fired power plants.

*Hydrology*

Power is subject to hydrology risk with its ownership of hydroelectric power generation facilities in the Northeastern U.S. Climate changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the company.

*Uncontracted Volumes*

Sale of uncontracted power in the open market is subject to market price volatility which directly impacts earnings. TransCanada has uncontracted sales volumes in both its Eastern Operations and Western Operations. In addition, with the acquisition of the Sheerness PPA in late 2005, Western Operations significantly increased its level of uncontracted sales volumes which are subject to price volatility in the Alberta wholesale marketplace. Although TransCanada seeks to generally secure sales under medium- to long-term contracts, TransCanada retains an amount of unsold generation in the short term in order to provide flexibility in managing the company's portfolio of owned assets. Also, Bruce B has a significant amount of uncontracted volumes sold into the wholesale spot market, although 100 per cent of the Bruce A output will be sold to the OPA under fixed price contract terms. Sales from the Bruce B Units 5 to 8 are subject to a floor price of $45 per MWh, adjusted annually for inflation on April 1.

*Execution and Capital Cost*

TransCanada, including its investment in Bruce Power, is subject to execution and capital cost risk. Bruce A's four unit restart and refurbishment program is subject to execution and capital cost risk. Bruce A and the OPA share capital costs that are above and below $4.25 billion on a 50/50 basis for cost overruns up to $618 million and 75/25 for any additional cost overruns. Similarly, Bruce A and OPA share 50/50 in cost benefits if costs are $240 million less than expected and 75/25 on the next $150 million of savings.

*Regulatory*

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively impact TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators or attempts to control the wholesale market by encouraging new plant construction. TransCanada continues to monitor regulatory issues and reform as well as participate in and lead discussions around these topics.

*Foreign Exchange*

TransCanada's earnings from Northeastern U.S. Operations are generated in U.S. dollars. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Power's net earnings, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

## POWER – OTHER

*Operational Excellence*

TransCanada's sale of Power LP to EPCOR allowed it to focus on larger, directly owned power assets. TC Hydro was effectively integrated in 2005 while maintaining high levels of operating performance. TransCanada continues its commitment to an operational excellence strategy of providing low cost, reliable performance.

## POWER – OUTLOOK

Net earnings from Bruce Power are expected to be higher in 2006 as a result of higher generation volumes of output from fewer planned outages and TransCanada's increased ownership in Bruce A. Bruce B earnings are subject to variability as a result of prices realized, and both Bruce A and Bruce B results are impacted by plant availability and operating expense levels. The overall plant availability percentage in 2006, for planning purposes, is expected to be in the low 90s for the four Bruce B units and in the low 80s for the two operating Bruce A units.

The contribution from Western Operations is expected to be higher in 2006 primarily due to the December 2005 acquisition of the Sheerness PPA. At December 31, 2005 a significant portion of the acquired generation from Sheerness was uncontracted. The intention for marketing the Sheerness output is the same as the Sundance output, whereby a significant portion of the power supply is expected to be sold under long-term contract, providing this is possible in the market. The repair of Bear Creek is a high priority in 2006 and management expects the facility to be back in service in mid-2006.

The contribution from Eastern Operations is expected to rise slightly in 2006 compared to 2005 due to a full year of ownership of the TC Hydro assets and the expected commercial in-service of Bécancour and the first of the Cartier wind farms in late 2006.

The loss of earnings resulting from the sale of Power LP in August 2005 will partially offset these impacts.

Earnings opportunities in Power may be affected by factors such as plant availability, fluctuating market prices for power and natural gas and ultimately market heat rates, regulatory changes, weather, sales of uncontracted volumes, currency movements and overall stability of the power industry. See "Power – Business Risks" for a complete discussion of these factors.

## CORPORATE

**CORPORATE RESULTS-AT-A-GLANCE**
*Year ended December 31 (millions of dollars)*

| | **2005** | 2004 | 2003 |
|---|---|---|---|
| Indirect financial charges and non-controlling interests | **130** | 79 | 89 |
| Interest income and other | **(29)** | (34) | (21) |
| Income taxes | **(65)** | (43) | (27) |
| Net expenses, after tax | **36** | 2 | 41 |

Corporate reflects net expenses not allocated to specific business segments, including:

- ***Indirect Financial Charges and Non-Controlling Interests*** Direct financial charges are reported in their respective business segments and are primarily associated with the debt and preferred securities related to the company's Wholly-Owned Pipelines. Indirect financial charges, including the related foreign exchange impacts, primarily reside in Corporate. These costs are directly impacted by the amount of debt that TransCanada maintains and the degree to which TransCanada is impacted by fluctuations in interest rates and foreign exchange.
- ***Interest Income and Other*** Interest income is primarily earned on invested cash balances. Gains and losses on foreign exchange related to working capital in Corporate are included in interest income and other.
- ***Income Taxes*** These include income taxes on corporate net expenses and income tax refunds and adjustments.

Net expenses, after tax, in Corporate were $36 million in 2005 compared to $2 million in 2004 and $41 million in 2003.

The increase of $34 million in net expenses in 2005 compared to 2004 was primarily due to increased interest expense on higher average long-term debt and commercial paper balances in 2005 as well as the release in 2004 of previously established restructuring provisions. Income tax refunds and positive tax adjustments were comparable in 2004 and 2005.

The decrease of $39 million in net expenses in 2004 compared to 2003 was primarily due to the positive impacts of income tax related items, including refunds received and the recognition of income tax benefits relating to additional loss carryforwards utilized, the release in 2004 of previously established restructuring provisions and positive impacts of foreign exchange related items.

In 2006, Corporate is expected to incur higher net expenses compared to 2005 primarily due to the income tax refunds and positive income tax adjustments recorded in 2005 that are not currently expected to recur in 2006. In addition, Corporate's results in 2006 could be impacted by debt levels, interest rates, foreign exchange movements and income tax refunds and adjustments. The performance of the Canadian dollar relative to the U.S. dollar would either positively or negatively impact Corporate's results, although this impact is mitigated by offsetting exposures in certain of TransCanada's other businesses as well as through the company's hedging activities.

## LIQUIDITY AND CAPITAL RESOURCES

### HIGHLIGHTS

*Investing Activities*

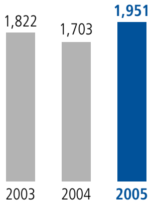
- Total capital expenditures and acquisitions, including assumed debt, were approximately $6.0 billion over the past three years.

*Dividend*

- TransCanada's Board of Directors has increased quarterly common share dividend payments for the past six consecutive years, including a five per cent increase to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006.

*Funds Generated from Operations*

**Funds Generated from Operations** (millions of dollars)



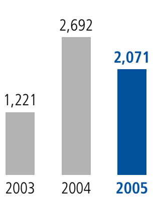

Funds generated from operations were approximately $2.0 billion for 2005 compared to approximately $1.7 billion and $1.8 billion, for 2004 and 2003, respectively. The Gas Transmission business was the primary source of funds generated from operations for each of the three years. As a result of rapid growth in the Power business in the last few years, the Power segment's funds generated from operations increased in 2005 compared to the two prior years. The decrease in 2004 compared to 2003 was mainly a result of higher current income tax expense in 2004 compared to 2003.

At December 31, 2005, TransCanada's ability to generate adequate amounts of cash in the short term and the long term when needed, and to maintain financial capacity and flexibility to provide for planned growth, was consistent with recent years.

*Investing Activities*

Capital expenditures, excluding acquisitions, totalled $754 million in 2005 compared to $530 million in 2004 and $395 million in 2003, respectively. Expenditures in all three years related primarily to construction of new power plants in Canada and maintenance and capacity capital in TransCanada's Gas Transmission business.

**Capital Expenditures and Acquisitions, including Assumed Debt** (millions of dollars)




During 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA for $585 million, invested a net cash outlay of $100 million in Bruce A as part of the Bruce Power reorganization, purchased the TC Hydro assets for US$503 million and acquired an additional 3.5 per cent ownership interest in Iroquois Gas Transmission System L.P. for US$14 million. In 2005, TransCanada sold its ownership interest in Power LP for proceeds of $444 million, net of current tax, its approximate 11 per cent ownership interest in Paiton Energy for proceeds of $125 million, net of current tax, and PipeLines LP units for proceeds of $102 million, net of current tax.

During 2004, TransCanada acquired GTN for US$1.2 billion, excluding assumed debt of approximately US$0.5 billion, and sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, excluding closing adjustments.

During 2003, TransCanada acquired a 31.6 per cent interest in Bruce Power for $409 million, the remaining interests in Foothills previously not held by the company for $105 million, excluding assumed debt of $154 million, and increased its interest in Portland to 61.7 per cent from 33.3 per cent for US$51 million, excluding assumed debt of US$78 million.

*Financing Activities*

In 2005, TransCanada retired long-term debt of $1,113 million. In June 2005, Gas Transmission Northwest Corporation (GTNC) redeemed all of its outstanding US$150 million 7.80 per cent Senior Unsecured Debentures (Debentures). As a consequence, upon application by GTNC, the Debentures were de-listed from the New York Stock Exchange and GTNC no longer has any securities registered under U.S. securities laws. In June 2005, GTNC completed a US$400 million multi-tranche private placement of senior debt with a weighted average interest rate of 5.28 per cent and weighted average life of approximately 18 years. In 2005, TransCanada also issued $300 million of 5.10 per cent medium-term notes due 2017 under the company's Canadian shelf prospectus. The company increased its notes payable by $416 million during 2005.

In 2004, TransCanada retired long-term debt of $1,005 million. The company issued $200 million of 4.10 per cent medium-term notes due 2009, US$350 million of 5.60 per cent senior unsecured notes due 2034 and US$300 million of 4.875 per cent senior unsecured notes due 2015. The company increased its notes payable by $179 million during 2004.

In 2003, TransCanada repaid long-term debt of $753 million, reduced notes payable by $62 million and redeemed all of its outstanding US$160 million, 8.75 per cent Junior Subordinated Debentures. The company issued $450 million of ten year, 5.65 per cent medium-term notes and US$350 million of ten year, 4.00 per cent senior unsecured notes.

Dividends on common shares of $586 million were paid in 2005 compared to $552 million in 2004 and $510 million in 2003.

In January 2006, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.32 per share from $0.305 per share for the quarter ending March 31, 2006. This was the sixth consecutive year of dividend increase since the $0.20 per share declared for fourth quarter 2000, which represents a 60 per cent increase in per share dividends since 2000.

Certain terms of the preferred shares, preferred securities and debt instruments of TransCanada PipeLines Limited (TCPL), a wholly-owned subsidiary of TransCanada, could restrict TCPL's ability to declare dividends on preferred and common shares. At December 31, 2005, under the most restrictive provisions, approximately $1.6 billion was available for the payment of dividends on TCPL's common shares which are held 100 per cent by TransCanada.

Financing activities included a net reduction in TransCanada's proportionate share of non-recourse debt of joint ventures of $42 million in 2005 compared to a net increase of $105 million in 2004 and a net decrease of $12 million in 2003.

*Credit Activities*

At December 31, 2005, TCPL had shelf prospectuses that qualified for issuance $1.2 billion of medium-term notes in Canada and US$1 billion of debt securities in the U.S. In January 2006, $300 million of 4.3 per cent medium-term notes due 2011 were issued under the Canadian shelf prospectus.

At December 31, 2005, total credit facilities of $2.0 billion were available to support the company's commercial paper program and for general corporate purposes. Of this total, $1.5 billion is a committed five-year term syndicated credit facility. The facility is extendible on an annual basis and is revolving. In December 2005, the maturity date of this facility was extended to December 2010. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2005, TransCanada had used approximately $271 million of its total lines of credit for letters of credit and to support ongoing commercial arrangements. If drawn, interest on the lines of credit would be charged at prime rates of Canadian chartered and U.S. banks or at other negotiated financial bases.

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is A3 with a stable outlook. Credit ratings on TCPL's senior unsecured debt assigned by Dominion Bond Rating Service Limited (DBRS), Moody's and Standard & Poor's are currently A, A2 and A−, respectively. DBRS and Moody's both maintain a 'stable' outlook on their ratings and Standard & Poor's maintains a 'negative' outlook on its rating.

## CONTRACTUAL OBLIGATIONS

### *Obligations and Commitments*

Total long-term debt at December 31, 2005 was approximately $10.0 billion compared to approximately $10.5 billion at December 31, 2004. TransCanada's share of total debt of joint ventures at December 31, 2005 was $978 million compared to $893 million at December 31, 2004. Total notes payable at December 31, 2005, including TransCanada's proportionate share of the notes payable of joint ventures, were $962 million compared to $546 million at December 31, 2004. The security provided by each joint venture, except the capital lease obligations at Bruce Power, is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power.

Effective January 1, 2005, under new Canadian accounting standards, the non-controlling interest component of preferred securities was classified as long-term debt.

At December 31, 2005, scheduled principal repayments and interest payments related to long-term debt and the company's proportionate share of the long-term debt of joint ventures are as follows.

**PRINCIPAL REPAYMENTS**
*Year ended December 31 (millions of dollars)*

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011+ |
|---|---|---|---|---|---|---|
| Long-term debt | 393 | 604 | 547 | 742 | 416 | 7,331 |
| Long-term debt of joint ventures | 41 | 28 | 29 | 89 | 286 | 505 |
| Total principal repayments | 434 | 632 | 576 | 831 | 702 | 7,836 |

**INTEREST PAYMENTS**
*Year ended December 31 (millions of dollars)*

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011+ |
|---|---|---|---|---|---|---|
| Interest payments on long-term debt | 806 | 784 | 734 | 682 | 637 | 7,320 |
| Interest payments on long-term debt of joint ventures | 70 | 68 | 67 | 64 | 52 | 356 |
| Total interest payments | 876 | 852 | 801 | 746 | 689 | 7,676 |

At December 31, 2005, future annual payments, net of sub-lease receipts, under the company's operating leases for various premises, services, equipment and a natural gas storage facility are approximately as follows.

**OPERATING LEASE PAYMENTS**
*Year ended December 31 (millions of dollars)*

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011+ |
|---|---|---|---|---|---|---|
| Minimum lease payments | 46 | 52 | 54 | 54 | 53 | 646 |
| Amounts recoverable under sub-leases | (12) | (12) | (12) | (11) | (11) | (13) |
| Net payments | 34 | 40 | 42 | 43 | 42 | 633 |

The operating lease agreements for premises, services and equipment expire at various dates through 2011, with an option to renew certain lease agreements for five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015.

At December 31, 2005, the company's future purchase obligations are approximately as follows.

**PURCHASE OBLIGATIONS**[(1)]
*Year ended December 31 (millions of dollars)*

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011+ |
|---|---|---|---|---|---|---|
| **Gas Transmission** | | | | | | |
| Transportation by others[(2)] | 179 | 175 | 131 | 89 | 79 | 52 |
| Other | 253 | 16 | 12 | 3 | – | – |
| **Power** | | | | | | |
| Commodity purchases[(3)] | 1,163 | 1,039 | 881 | 522 | 525 | 4,802 |
| Capital expenditures[(4)] | 534 | 390 | 145 | 70 | – | – |
| Other[(5)] | 52 | 56 | 32 | 21 | 29 | 92 |
| **Corporate** | | | | | | |
| Information technology and other | 16 | 14 | 14 | 14 | 7 | 14 |
| Total purchase obligations | 2,197 | 1,690 | 1,215 | 719 | 640 | 4,960 |

(1) The amounts in this table exclude funding contributions to pension plans and funding to the APG.

(2) Rates are based on known 2006 levels. Beyond 2006, demand rates are subject to change. The contract obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow. Transportation by others is generally included in the revenue requirements of the regulated pipelines.

(3) Commodity purchases include fixed and variable components. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(4) Amounts are estimates and are subject to variability based on timing of construction and project enhancements.

(5) Includes estimates of certain amounts which are subject to change depending on plant fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

During 2006, TransCanada expects to make funding contributions to the company's pension plans and other benefit plans in the amount of approximately $95 million and $7 million, respectively. The expected increase in total funding in 2006 from $74 million in 2005 is due to continued reductions in discount rates used to calculate plan obligations partially offset by investment performance above long-term expectations in 2005. During 2006, TransCanada's proportionate share of expected funding contributions to be made by joint ventures to their respective pension plans and other benefit plans is approximately $27 million and $2 million, respectively.

*Bruce Power*

Included in Power's capital expenditures in the table above is TransCanada's share of Bruce A's signed commitments to third party suppliers for the next five years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replacing the steam generators on Unit 4, as follows.

| *Year ended December 31 (millions of dollars)* | |
|---|---|
| 2006 | 322 |
| 2007 | 311 |
| 2008 | 142 |
| 2009 | 69 |
| 2010 | – |
| | 844 |

*Aboriginal Pipeline Group*

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. These costs were originally estimated to be approximately $90 million, but given extended project delays, the protracted regulatory process and the projected timing to reach a decision to construct the pipeline, this share is currently forecast to increase to approximately $145 million. As at December 31, 2005, TransCanada had funded $87 million (2004 – $60 million) of this loan which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are or were transacted at market prices and in the normal course of business.

*Guarantees*

TransCanada had no outstanding guarantees related to the long-term debt of unrelated third parties at December 31, 2005.

The company, together with Cameco and BPC, has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement, and contractor services. The terms of the guarantees currently range from 2018 to 2019.

As part of the reorganization of Bruce Power, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the OPA and cost sharing and sublease agreements with Bruce B. The terms of the guarantees range from 2019 to 2036.

TransCanada's share of the net exposure under these Bruce Power guarantees at December 31, 2005 was estimated to be approximately $652 million of a calculated maximum of $758 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$133 million of public debt obligations of TransGas. The company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US$241 million of the purchase price was deposited into an escrow account. As at December 31, 2005, there was US$54 million remaining in the escrow account. The outstanding funds in the escrow account represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability of GTN under these designated guarantees.

*Contingencies*

The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners commenced an action in 2003 under Ontario's *Class Proceedings Act, 1992*, against TransCanada and Enbridge Inc. for damages of $500 million alleged to arise from the creation of a control zone within 30 metres of the pipeline pursuant to Section 112 of the *NEB Act*. The company believes the claim is without merit and will vigorously defend the action. The company has made no provision for any potential liability. A liability, if any, would be dealt with through the regulatory process.

The company and its subsidiaries are subject to various other legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the company's consolidated financial position or results of operations.

## FINANCIAL AND OTHER INSTRUMENTS

The company issues short-term and long-term debt, purchases and sells energy commodities including amounts in foreign currencies, and invests in foreign operations. These activities result in exposures to interest rates, energy commodity prices and foreign currency exchange rates. The company utilizes derivatives to manage the risk that results from these activities.

Derivatives and other instruments must be designated and effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, net of tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction giving rise to the exposure being economically hedged. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on derivatives for Canadian Mainline, Alberta System, the Foothills System and the BC System exposures is determined through the regulatory process.

The fair value of foreign exchange and interest rate derivatives has been estimated using year-end market rates. The fair value of power, natural gas and heat rate derivatives has been calculated using estimated forward prices for the relevant period.

*Net Investment in Foreign Operations*
At December 31, 2005 and 2004, the company had net investments in self sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

**Asset/(Liability)**

| | | **2005** | | 2004 | |
|---|---|---|---|---|---|
| *December 31 (millions of dollars)* | Accounting Treatment | **Fair Value** | **Notional or Notional Principal Amount** | Fair Value | Notional or Notional Principal Amount |
| U.S. dollar cross-currency swaps (maturing 2006 to 2012) | Hedge | **119** | **U.S. 450** | 95 | U.S. 400 |
| U.S. dollar forward foreign exchange contracts (maturing 2006) | Hedge | **5** | **U.S. 525** | (1) | U.S. 305 |
| U.S. dollar options (maturing 2006) | Hedge | **–** | **U.S. 60** | 1 | U.S. 100 |

**Reconciliation of Foreign Exchange Adjustment (Losses)/Gains**

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Balance at January 1 | **(71)** | (40) |
| Translation losses on foreign currency denominated net assets(1) | **(21)** | (39) |
| Gains on derivatives | **23** | 52 |
| Income taxes | **(21)** | (44) |
| Balance at December 31 | **(90)** | (71) |

(1) In 2005, includes gains of $80 million (2004 – $101 million) related to foreign currency denominated debt designated as a hedge.

*Foreign Exchange Gains/(Losses)*
Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2005 are $19 million (2004 – $6 million; 2003 – nil).

*Foreign Exchange and Interest Rate Management Activity*

The company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt, and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

**Asset/(Liability)**

| *December 31 (millions of dollars)* | Accounting Treatment | **2005** Fair Value | **2005** Notional or Notional Principal Amount | 2004 Fair Value | 2004 Notional or Notional Principal Amount |
|---|---|---|---|---|---|
| **Foreign Exchange** | | | | | |
| Cross-currency swaps (maturing 2010 to 2013) | Non-hedge | **(86)** | **363/U.S. 257** | (69) | 363/U.S. 257 |
| **Interest Rate** | | | | | |
| Interest rate swaps | | | | | |
| Canadian dollars | | | | | |
| (maturing 2007 to 2008) | Hedge | **4** | **100** | 7 | 145 |
| (maturing 2006 to 2009) | Non-hedge | **7** | **374** | 9 | 374 |
| | | **11** | | 16 | |
| U.S. dollars | | | | | |
| (maturing 2007 to 2009) | Non-hedge | **5** | **U.S. 100** | 7 | U.S. 100 |

The company manages the foreign exchange and interest rate exposures of its other businesses through the use of foreign currency and interest rate derivatives. The details of these foreign currency and interest rate derivatives are shown in the table below.

**Asset/(Liability)**

| *December 31 (millions of dollars)* | Accounting Treatment | **2005** Fair Value | **2005** Notional or Notional Principal Amount | 2004 Fair Value | 2004 Notional or Notional Principal Amount |
|---|---|---|---|---|---|
| **Foreign Exchange** | | | | | |
| Options (maturing 2006) | Non-hedge | **1** | **U.S. 195** | 2 | U.S. 255 |
| Forward foreign exchange contracts | | | | | |
| (maturing 2006) | Hedge | **2** | **U.S. 29** | – | – |
| (maturing 2006) | Non-hedge | **1** | **U.S. 208** | 1 | U.S. 129 |
| **Interest Rate** | | | | | |
| Options | Non-hedge | **–** | **–** | – | U.S. 50 |
| Interest rate swaps | | | | | |
| Canadian dollar | | | | | |
| (maturing 2007 to 2009) | Hedge | **1** | **100** | 4 | 100 |
| (maturing 2006 to 2011) | Non-hedge | **1** | **423** | 5 | 485 |
| | | **2** | | 9 | |
| U.S. dollar | | | | | |
| (maturing 2013) | Hedge | **–** | **U.S. 50** | 3 | U.S. 375 |
| (maturing 2006 to 2010) | Non-hedge | **18** | **U.S. 550** | 22 | U.S. 500 |
| | | **18** | | 25 | |

Certain of the company's joint ventures use interest rate derivatives to manage interest rate exposures. The company's proportionate share of the fair value of the outstanding derivatives at December 31, 2005 was nil (2004 – $1 million).

*Energy Price Risk Management*

The company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, future, option and heat rate contracts are shown in the tables below.

**Power**

**Asset/(Liability)**

| *December 31 (millions of dollars)* | Accounting Treatment | **2005** Fair Value | 2004 Fair Value |
|---|---|---|---|
| Power – swaps and contracts for differences | | | |
| (maturing 2006 to 2011) | Hedge | **(130)** | 7 |
| (maturing 2006 to 2010) | Non-hedge | **13** | (2) |
| Gas – swaps, futures and options | | | |
| (maturing 2006 to 2016) | Hedge | **17** | (39) |
| (maturing 2006 to 2008) | Non-hedge | **(11)** | (2) |
| Heat rate contracts | | | |
| (maturing 2006) | Non-hedge | **–** | (1) |

**Notional Volumes**

| | Accounting | **Power (GWh)** | | **Gas (Bcf)** | |
|---|---|---|---|---|---|
| *December 31, 2005* | Treatment | **Purchases** | **Sales** | **Purchases** | **Sales** |
| Power – swaps and contracts for differences | | | | | |
| (maturing 2006 to 2011) | Hedge | **2,566** | **7,780** | **–** | **–** |
| (maturing 2006 to 2010) | Non-hedge | **1,332** | **456** | **–** | **–** |
| Gas – swaps, futures and options | | | | | |
| (maturing 2006 to 2016) | Hedge | **–** | **–** | **91** | **69** |
| (maturing 2006 to 2008) | Non-hedge | **–** | **–** | **15** | **18** |
| Heat rate contracts | | | | | |
| (maturing 2006) | Non-hedge | **–** | **35** | **–** | **–** |
| *December 31, 2004* | | | | | |
| Power – swaps and contracts for differences | Hedge | 3,314 | 7,029 | – | – |
| | Non-hedge | 438 | – | – | – |
| Gas – swaps, futures and options | Hedge | – | – | 80 | 84 |
| | Non-hedge | – | – | 5 | 8 |
| Heat rate contracts | Non-hedge | – | 229 | 2 | – |

Certain of the company's joint ventures use power derivatives to manage energy price risk exposures. The company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2005 was $(38) million (2004 – nil) and relates to contracts which cover the period 2006 to 2008. The company's proportionate share of the notional sales volumes associated with this exposure at December 31, 2005 was 2,058 GWh (2004 – nil).

## RISK MANAGEMENT

*Risk Management Overview*
TransCanada and its subsidiaries are exposed to market, financial and counterparty risks in the normal course of their business activities. The risk management function assists in managing these various business activities and the risks associated with them. A strong commitment to a risk management culture by TransCanada's management supports this function. TransCanada's primary risk management objective is to protect earnings and cash flow and ultimately, shareholder value.

The risk management function is guided by the following principles that are applied to all businesses and risk types:

- *Board Oversight* – Risk strategies, policies and limits are subject to review and approval by TransCanada's Board of Directors.
- *Independent Review* – Risk-taking activities are subject to independent review, separate from the business lines that initiate the activity.
- *Assessment* – Processes are in place to ensure that risks are properly assessed at the transaction and counterparty levels.
- *Review and Reporting* – Market positions and exposures, and the creditworthiness of counterparties are subject to ongoing review and reporting to executive management.
- *Accountability* – Business lines are accountable for all risks and the related returns for their particular businesses.
- *Audit Review* – Risk processes are subject to internal audit review, with independent reporting to the Audit Committee of TransCanada's Board of Directors.

The processes within TransCanada's risk management function are designed to ensure that risks are properly identified, quantified, reported and managed. Risk management strategies, policies and limits are designed to ensure TransCanada's risk taking is consistent with the company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the company's Board of Directors and implemented by senior management, monitored by risk management personnel and audited by internal audit personnel.

TransCanada manages market, financial and counterparty risks and related exposures in accordance with the company's market risk, interest rate and foreign exchange risk, and counterparty risk policies. The company's primary market and financial risks result from volatility in commodity positions and prices, interest rates and foreign currency exchange rates. Senior management reviews these exposures and reports on a regular basis to the Audit Committee of TransCanada's Board of Directors.

*Market Risk Management*
In order to manage market risk exposures created by fixed and variable pricing arrangements at different pricing indices and delivery points, the company enters into offsetting physical positions and derivative financial instruments. Market risks are quantified using value-at-risk methodology and are reviewed weekly by senior management.

*Financial Risk Management*
TransCanada monitors the financial market risk exposures relating to the company's investments in foreign currency denominated net assets, regulated and non-regulated long-term debt portfolios and foreign currency exposure on transactions. The market risk exposures created by these business activities are managed by establishing offsetting positions or through the use of derivative financial instruments.

*Counterparty Risk Management*
Counterparty risk is the financial loss that the company would experience if the counterparty failed to meet its obligations in accordance with the terms and conditions of its contracts with the company. Counterparty risk is mitigated by conducting financial and other assessments to establish a counterparty's creditworthiness, setting exposure limits and monitoring exposures against these limits, and, where warranted, obtaining financial assurances.

The company's counterparty risk management practices and positions are further described in Note 16 to the consolidated financial statements.

### *Risks and Risk Management Related to the Kyoto Protocol*

TransCanada is in the business of transporting natural gas and generating electricity to meet the growing energy needs of businesses and consumers throughout North America. While expanding the company's businesses, TransCanada continuously identifies and takes action to manage issues that could affect the company's ability to provide consumers with safe, reliable and cost-effective energy supplies. Among these issues are business risks associated with greenhouse gas emissions.

In Canada, TransCanada's fossil-fired power plants, pipeline assets and carbon black facilities are expected to be covered under legislation for large final emitters. While the broad elements of the proposed regulations to reduce greenhouse gas emissions intensities from large industrial emitters have been established, key policy elements remain outstanding, including details of compliance options that entities may use to fulfill compliance obligations. At this time, it is difficult to determine the level of impact to the company's Canadian assets until these and other key policy elements have been defined.

In 2006, TransCanada will continue with its strategy for managing the climate change issue. This strategy includes activities such as:

- energy conservation through improvements to overall system efficiency;
- conducting research and development work designed to reduce greenhouse gas emissions;
- gaining experience with flexible market mechanisms;
- participation in government-led policy forums; and
- taking part in public awareness initiatives and education programs focused on climate change and air quality issues.

In addition to these activities, TransCanada also ensures that the potential business risks and opportunities posed by increasing environmental priorities are considered when making decisions regarding the company's businesses.

### *Disclosure Controls and Procedures and Internal Controls*

Pursuant to regulations adopted by the U.S. Securities and Exchange Commission (SEC), under the *Sarbanes-Oxley Act of 2002* and those of the Canadian Securities Administrators, TransCanada's management evaluates the effectiveness of the design and operation of the company's disclosure controls and procedures (disclosure controls). This evaluation is done under the supervision of, and with the participation of, the President and Chief Executive Officer and the Chief Financial Officer.

As of the end of the period covered by this Annual Report, TransCanada's management evaluated the effectiveness of its disclosure controls. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that TransCanada's disclosure controls are effective in ensuring that material information relating to TransCanada is made known to management on a timely basis, and is included in this Annual Report.

During the period covered by this Annual Report, there has been no change in internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, TransCanada's internal control over financial reporting.

### *CEO and CFO Certifications*

With respect to the year ending December 31, 2005, TransCanada's President and Chief Executive Officer has provided the New York Stock Exchange with the annual CEO certification regarding TransCanada's compliance with the New York Stock Exchange's corporate governance listing standards applicable to foreign issuers. In addition, TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2005 reports filed with the SEC.

*Compliance Expenditures*
The total cost incurred by TransCanada to meet compliance requirements of Sections 302, 404 and 906 of the *Sarbanes-Oxley Act of 2002* for the period January 1, 2002 to December 31, 2005, was estimated to be $9 million, including third party charges of $3 million.

## CRITICAL ACCOUNTING POLICY

The company accounts for the impacts of rate regulation in accordance with generally accepted accounting principles (GAAP) as outlined in Notes 1 and 12 to the consolidated financial statements. Three criteria must be met to use these accounting principles: the rates for regulated services or activities must be subject to approval by a regulator; the regulated rates must be designed to recover the cost of providing the services or products; and it must be reasonable to assume that rates set at levels to recover the cost can be charged to and will be collected from customers in view of the demand for services or products and the level of direct and indirect competition. The company's management believes that all three of these criteria have been met. The most significant impact from the use of these accounting principles is that in order to appropriately reflect the economic impact of the regulators' decisions regarding the company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP as detailed in Note 12 to the consolidated financial statements.

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized as it is expected that when these amounts become payable, they will be recovered through future rate revenues. In the absence of rate regulation accounting, GAAP would require the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,619 million at December 31, 2005 would have been recorded.

## CRITICAL ACCOUNTING ESTIMATE

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the company's consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. TransCanada's critical accounting estimate is depreciation expense. TransCanada's plant, property and equipment are depreciated on a straight-line basis over their estimated useful lives. Depreciation expense for the year ended December 31, 2005 was $1,017 million. Depreciation expense impacts the Gas Transmission and Power segments of the company. In the Gas Transmission business, depreciation rates are approved by the regulators, where applicable, and depreciation expense is recoverable based on the cost of providing the services or products. A change in the estimation of the useful lives of the plant, property and equipment in the Gas Transmission segment would, if recovery through rates is permitted by the regulators, have no material impact on TransCanada's net income but would directly impact funds generated from operations.

## ACCOUNTING CHANGES

*Financial Instruments – Disclosure and Presentation*
Effective January 1, 2005, the Company adopted the amendment of the Canadian Institute of Chartered Accountants (CICA) to the existing Handbook Section "Financial Instruments – Disclosure and Presentation" which provides guidance for classifying certain financial instruments that embody obligations that may be settled by the issuance of the issuer's equity shares as debt when the instrument that embodies the obligations does not establish an ownership relationship. In accordance with this amendment, TransCanada classified the non-controlling interest component of preferred

securities as long-term debt. This change was applied retroactively with restatement of prior periods. See Note 2 to the consolidated financial statements for the impact of this accounting change.

*Disclosure by Entities Subject to Rate Regulation*
In May 2005, the Accounting Standards Board (AcSB) issued Accounting Guideline AcG-19 "Disclosures by Entities Subject to Rate Regulation" to improve the quality and consistency of disclosures by entities subject to rate regulation. Under AcG-19, all rate regulated entities are required to disclose general information about the rate-setting process, its accounting effects and the operations affected. The new disclosure requirements were effective for fiscal years ending on or after December 31, 2005. The company adopted these requirements effective December 31, 2005. See Note 12 to the consolidated financial statements for disclosures required under AcG-19.

*Limited Partnerships*
A wholly-owned subsidiary of TransCanada serves as the general partner of PipeLines LP. Effective December 31, 2005, TransCanada consolidated limited partnerships when the general partner controls the strategic operating, financing and investing activities of the limited partnerships and the limited partners do not have substantive participating rights. This change was applied retroactively with restatement of prior periods. There was no impact on previously recorded net income and the balance sheet and income statement impact was not material.

*Consolidation of Variable Interest Entities*
In June 2003, the Accounting Standards Board of the CICA issued a new Accounting Guideline "Consolidation of Variable Interest Entities" which requires enterprises to identify variable interest entities in which they have an interest, determine whether they are the primary beneficiary of such entities and, if so, to consolidate them. For TransCanada, the guideline's requirements were effective as of January 1, 2005. Adopting the provisions of this guideline had no impact on the company's consolidated financial statements.

*Non-Monetary Transactions*
In June 2005, the AcSB issued the new Handbook Section 3831 "Non-Monetary Transactions" replacing Section 3830 of the same title. The revised standard requires all non-monetary transactions to be measured at fair value, subject to certain exceptions. Commercial substance replaces culmination of the earnings process as the test for fair value measurement and is a function of the cash flows expected from the exchanged assets. The new requirements are effective for non-monetary transactions initiated in periods beginning on or after January 1, 2006. Adopting the provisions of this standard is not expected to have an impact on the company's consolidated financial statements.

*Financial Instruments – Recognition and Measurement*
In January 2005, the AcSB issued the new Handbook Section 3855 "Financial Instruments – Recognition and Measurement" which prescribes that all financial instruments within the scope of this standard, including derivatives, be included on a company's balance sheet and measured, either at their fair value or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. It also specifies when gains and losses as a result of changes in fair value are to be recognized in the income statement. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. This standard is substantially similar to the corresponding requirements under Statement of Financial Accounting Standards (SFAS) No. 115 "Accounting for Certain Investments in Debt and Equity Securities" and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" which were adopted by the company for U.S. GAAP purposes, effective January 1, 2001. This new Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new Canadian requirement to have a significant impact on the company's consolidated financial statements. See the company's reconciliation to United States GAAP posted on www.sec.gov/edgar.shtml for the impact of SFAS No. 133 on the company's consolidated financial statements.

*Hedges*
In January 2005, the AcSB issued the new Handbook Section 3865 "Hedges" which specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed, and where the impacts should be recorded. The provisions of this standard introduce three specific types of hedging relationships: fair value hedges, cash

flow hedges and hedges of a net investment in self-sustaining foreign operations. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. The standard builds on existing Accounting Guideline AcG-13 "Hedging Relationships" which was adopted by TransCanada effective January 1, 2004. This new Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new requirement to have a significant impact on the company's consolidated financial statements.

*Comprehensive Income*

In January 2005, the AcSB issued the new Handbook Section 1530 "Comprehensive Income" which requires that an enterprise present comprehensive income and its components, in a separate financial statement that is displayed with the same prominence as other financial statements. This Section introduces a new requirement to present certain gains and losses temporarily outside net income. This standard is effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006. This standard is substantially similar to the corresponding requirements under SFAS No. 130 "Reporting Comprehensive Income" and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" which have already been adopted by the company for U.S. GAAP purposes. This Handbook section will be adopted by the company as of January 1, 2007 on a prospective basis. TransCanada does not expect the new Canadian requirement to have a significant impact on the company's consolidated financial statements. See the company's reconciliation to United States GAAP posted on www.sec.gov/edgar.shtml for the impact of SFAS No. 130 and SFAS No. 133 on the company's consolidated financial statements.

## DISCONTINUED OPERATIONS

TransCanada's Board of Directors approved plans in previous years to dispose of the company's International, Canadian Midstream, Gas Marketing and certain other businesses. As of December 31, 2003, TransCanada's investments in Gasoducto del Pacifico (Gas Pacifico), INNERGY Holdings S.A. (INNERGY) and Paiton Energy, which were previously approved for disposal, were accounted for as part of continuing operations due to the length of time it had taken the company to dispose of these assets. Gas Pacifico and INNERGY are included in the Gas Transmission segment. It is the intention of the company to continue with its plan to dispose of these investments. Paiton Energy was sold in November 2005 and the gain on sale was recorded in the Power segment.

In 2005, the company reviewed the provision for loss on discontinued operations and concluded that the provision was adequate.

In 2004 and 2003, the company recognized in income $52 million and $50 million, respectively, related to the original $102 million after-tax deferred gain on the sale of Gas Marketing.

## SUBSIDIARIES AND INVESTMENTS

TransCanada's subsidiaries and investments that hold significant operating assets are noted below.

| Subsidiary Investment | Major Operating Assets | Organized Under the Laws of | Effective Percentage Ownership by TransCanada[1] |
|---|---|---|---|
| TransCanada PipeLines Limited | Canadian Mainline and BC System | Canada | 100 |
| NOVA Gas Transmission Ltd. | Alberta System | Alberta | 100 |
| TransCanada Pipeline Ventures Ltd. | Ventures LP | Alberta | 100 |
| Foothills Pipe Lines Ltd. | Foothills System | Canada | 100 |
| TransCanada PipeLine USA Ltd. | | Nevada | 100 |
| TransCanada Hydro Northeast Inc. | TC Hydro | Delaware | 100 |
| Gas Transmission Northwest Corporation | GTN | California | 100 |
| TransCanada Power Marketing Ltd. | U.S. Power assets | Delaware | 100 |
| Great Lakes Gas Transmission Limited Partnership | Great Lakes | Delaware | 50 |
| Iroquois Gas Transmission System L.P. | Iroquois | Delaware | 44.5 |
| Portland Natural Gas Transmission System Partnership | Portland | Maine | 61.7 |
| TC PipeLines, LP | TC PipeLines, LP assets | Delaware | 13.4 |
| Northern Border Pipeline Company | Northern Border | Texas | 4 |
| Tuscarora Gas Transmission Company | Tuscarora | Nevada | 7.6 |
| TransCanada Energy Ltd. | Canadian Power assets | Canada | 100 |
| Bruce Power A L.P. | Bruce A Units 1 to 4 | Ontario | 47.9 |
| Bruce Power L.P. | Bruce B Units 5 to 8 | Ontario | 31.6 |
| Trans Québec & Maritimes Pipeline Inc. | TQM | Canada | 50 |
| CrossAlta Gas Storage & Services Ltd. | CrossAlta | Alberta | 60 |
| TransGas de Occidente S.A. | TransGas | Colombia | 46.5 |

[1] Percentage ownership represents the effective common share ownership as at December 31, 2005.

**SELECTED THREE YEAR CONSOLIDATED FINANCIAL DATA**[1]
*(millions of dollars except per share amounts)*

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Income Statement** | | | |
| Revenues | **6,124** | 5,497 | 5,636 |
| Net income | | | |
| Continuing operations | **1,209** | 980 | 801 |
| Discontinued operations | **–** | 52 | 50 |
| Total | **1,209** | 1,032 | 851 |
| **Balance Sheet** | | | |
| Total assets | **24,113** | 22,422 | 20,887 |
| Long-term debt | **9,640** | 9,749 | 9,516 |
| Non-recourse debt of joint ventures | **937** | 808 | 741 |
| Preferred securities | **536** | 554 | 598 |
| **Per Common Share Data** | | | |
| Net income – Basic | | | |
| Continuing operations | **$2.49** | $2.02 | $1.66 |
| Discontinued operations | **–** | 0.11 | 0.10 |
| | **$2.49** | $2.13 | $1.76 |
| Net income – Diluted | | | |
| Continuing operations | **$2.47** | $2.01 | $1.66 |
| Discontinued operations | **–** | 0.11 | 0.10 |
| | **$2.47** | $2.12 | $1.76 |
| Dividends declared | **$1.22** | $1.16 | $1.08 |

(1) The selected three year consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Note 1, Note 2 and Note 23 of TransCanada's 2005 audited consolidated financial statements.

**SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA**[1]

| | 2005 | | | |
|---|---|---|---|---|
| *(millions of dollars except per share amounts)* | **Fourth** | **Third** | **Second** | **First** |
| Revenues | **1,771** | **1,494** | **1,449** | **1,410** |
| Net Income | | | | |
| Continuing operations | **350** | **427** | **200** | **232** |
| Discontinued operations | **–** | **–** | **–** | **–** |
| | **350** | **427** | **200** | **232** |
| Share Statistics | | | | |
| Net income per share – Basic | | | | |
| Continuing operations | **$0.72** | **$0.88** | **$0.41** | **$0.48** |
| Discontinued operations | **–** | **–** | **–** | **–** |
| | **$0.72** | **$0.88** | **$0.41** | **$0.48** |
| Net income per share – Diluted | | | | |
| Continuing operations | **$0.71** | **$0.87** | **$0.41** | **$0.48** |
| Discontinued operations | **–** | **–** | **–** | **–** |
| | **$0.71** | **$0.87** | **$0.41** | **$0.48** |
| Dividend declared per common share | **$0.305** | **$0.305** | **$0.305** | **$0.305** |

| | 2004 | | | |
|---|---|---|---|---|
| | Fourth | Third | Second | First |
| Revenues | 1,480 | 1,311 | 1,347 | 1,359 |
| Net Income | | | | |
| Continuing operations | 185 | 193 | 388 | 214 |
| Discontinued operations | – | 52 | – | – |
| | 185 | 245 | 388 | 214 |
| Share Statistics | | | | |
| Net income per share – Basic | | | | |
| Continuing operations | $0.38 | $0.40 | $0.80 | $0.44 |
| Discontinued operations | – | 0.11 | – | – |
| | $0.38 | $0.51 | $0.80 | $0.44 |
| Net income per share – Diluted | | | | |
| Continuing operations | $0.38 | $0.39 | $0.80 | $0.44 |
| Discontinued operations | – | 0.11 | – | – |
| | $0.38 | $0.50 | $0.80 | $0.44 |
| Dividend declared per common share | $0.29 | $0.29 | $0.29 | $0.29 |

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been reclassified to conform with the current year's presentation. For a discussion on the factors affecting the comparability of the financial data, including discontinued operations, refer to Note 1, Note 2 and Note 23 of TransCanada's 2005 audited consolidated financial statements.

*Factors Impacting Quarterly Financial Information*

In the Gas Transmission business, which consists primarily of the company's investments in regulated pipelines, annual revenues and net earnings fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter over quarter revenues and net earnings during any particular fiscal year remain relatively stable with fluctuations arising as a result of adjustments being recorded due to regulatory decisions and negotiated settlements with shippers and due to items outside of the normal course of operations.

In the Power business, which builds, owns and operates electrical power generation plants and sells electricity, quarter over quarter revenues and net earnings are affected by seasonal weather conditions, customer demand, market prices, planned and unplanned plant outages as well as items outside of the normal course of operations.

Significant items which impacted 2005 and 2004 quarterly net earnings are as follows.

- First quarter 2004 net earnings included approximately $12 million of income tax refunds and related interest.
- Second quarter 2004 net earnings included after-tax gains related to Power LP of $187 million, of which $132 million were previously deferred and were being amortized into income to 2017.
- In third quarter 2004, the EUB's decisions on the Generic Cost of Capital and Phase I of the 2004 GRA resulted in lower earnings for the Alberta System compared to the previous quarters. In addition, third quarter 2004 included a $12 million after-tax adjustment related to the release of previously established restructuring provisions and recognition of $8 million of non-capital loss carry forwards.
- In fourth quarter 2004, TransCanada completed the acquisition of GTN and recorded $14 million of net earnings from the November 1, 2004 acquisition date. Power recorded a $16 million pre-tax positive impact of a restructuring transaction related to power purchase contracts between OSP and Boston Edison in Eastern Operations.
- In first quarter 2005, net earnings included a $48 million after-tax gain related to the sale of PipeLines LP units. Power earnings included a $10 million after-tax cost for the restructuring of natural gas supply contracts by OSP. In addition, Bruce Power's equity income was lower than previous quarters due to the impact of planned maintenance outages and the increase in operating costs as a result of moving to a six-unit operation.
- Second quarter 2005 net earnings included $21 million ($13 million related to 2004 and $8 million related to the six months ended June 30, 2005) with respect to the NEB's decision on the Canadian Mainline's 2004 Tolls and Tariff Application (Phase II). On April 1, 2005, TransCanada completed the acquisition of the TC Hydro hydroelectric generation assets from USGen. Bruce Power's equity income was lower than previous quarters due to the continuing impact of planned maintenance outages and an unplanned maintenance outage on Unit 6 relating to a transformer fire.
- In third quarter 2005, net earnings included a $193 million after-tax gain related to the sale of the company's ownership interest in Power LP. In addition, Bruce Power's equity income increased from prior quarters due to higher realized power prices and slightly higher generation volumes.
- In fourth quarter 2005, net earnings included a $115 million after-tax gain on sale of Paiton Energy. In addition, Bruce A was formed and Bruce Power's results were proportionately consolidated, effective October 31.

## FOURTH QUARTER 2005 HIGHLIGHTS

### SEGMENT RESULTS-AT-A-GLANCE

*Three months ended December 31 (millions of dollars except per share amounts)*

| | 2005 | 2004 |
|---|---|---|
| **Gas Transmission** | **160** | 157 |
| **Power** | | |
| Excluding gains | **82** | 31 |
| Gain on sale of Paiton Energy | **115** | – |
| | **197** | 31 |
| **Corporate** | **(7)** | (3) |
| **Net Income**(1) | **350** | 185 |
| **Net Income Per Share – Basic**(2) | **$0.72** | $0.38 |

| | | |
|---|---|---|
| (1)**Net Income** | | |
| Excluding gain | **235** | 185 |
| Gain on sale of Paiton Energy | **115** | – |
| | **350** | 185 |
| (2)**Net Income Per Share – Basic** | | |
| Excluding gain | **$0.48** | $0.38 |
| Gain on sale of Paiton Energy | **0.24** | – |
| | **$0.72** | $0.38 |

Net income for fourth quarter 2005 of $350 million or $0.72 per share increased by $165 million or $0.34 per share compared to $185 million or $0.38 per share for fourth quarter 2004. This increase was due to significantly higher net income from the Power business, including an after-tax gain of $115 million or $0.24 per share from the sale of Paiton Energy.

Excluding the $115 million gain related to the sale of Paiton Energy, net income for fourth quarter 2005 increased $50 million or $0.10 per share compared to fourth quarter 2004, to $235 million or $0.48 per share. This was due to increases of $51 million and $3 million in net income from the Power and Gas Transmission businesses, respectively, partially offset by an increase of $4 million in net expenses in Corporate.

The increase in Power's net income was primarily due to higher operating and other income from Bruce Power and Eastern Operations. Bruce Power's contribution to operating and other income increased by $48 million in fourth quarter 2005 compared to fourth quarter 2004, primarily due to higher realized power prices on uncontracted volumes sold into Ontario's wholesale spot market, higher generation volumes and an increased ownership interest in the Bruce A facilities effective October 31, 2005.

Western Operations' operating and other income was $8 million higher in fourth quarter 2005 compared to fourth quarter 2004 primarily due to increased margins in fourth quarter 2005 as a result of higher market heat rates on uncontracted volumes of power sold. Partially offsetting this increase were lower contributions from the Bear Creek cogeneration facility which remained on an unplanned outage throughout the quarter.

Eastern Operations' operating and other income was $37 million higher in fourth quarter 2005 compared to fourth quarter 2004 primarily due to contributions from TC Hydro, acquired on April 1, 2005, and from the Grandview cogeneration facility placed into service in January 2005. Partially offsetting these increases was a fourth quarter 2004 positive impact due to a restructuring transaction relating to OSP power purchase contracts and the loss of operating income associated with the expiration of certain long-term sales contracts in 2004.

General, administrative, support costs and other increased $9 million in fourth quarter 2005 compared to fourth quarter 2004 primarily due to higher business development costs expensed in 2005 and the positive impact in fourth quarter 2004 of the recognition of unrealized foreign exchange gains on Power LP's U.S. dollar denominated debt.

For fourth quarter 2005, Gas Transmission's net income was $160 million compared to $157 million in fourth quarter 2004. The $3 million increase was due to a $6 million increase in net income from the Other Gas Transmission businesses partially offset by a $3 million reduction in income from Wholly-Owned Pipelines. The reduction in income from Wholly-Owned Pipelines was primarily due to a decline in the Canadian Mainline and the Alberta System net income. These decreases were partially offset by higher net income during the quarter from TransCanada's investment in GTN which was acquired on November 1, 2004. The increase in net income from Other Gas Transmission was primarily due to lower project development costs expensed in fourth quarter 2005 resulting from capitalization of costs of the Broadwater and Keystone projects in 2005 and higher income from Gas Pacifico. These increases were partially offset by lower income from Great Lakes and Ventures LP.

Net expenses, after tax, in Corporate for fourth quarter 2005 were $7 million compared to $3 million for the corresponding period in 2004. The $4 million increase in net expenses was primarily due to increased net interest costs offset by an income tax refund received in fourth quarter 2005 relating to prior years.

## SHARE INFORMATION

As at February 27, 2006, TransCanada had 487,489,628 issued and outstanding common shares. In addition, there were 9,661,488 outstanding options to purchase common shares, of which 7,303,084 were exercisable as at February 27, 2006.

## OTHER INFORMATION

Additional information relating to TransCanada, including the company's Annual Information Form and continuous disclosure documents, is posted on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for the years ended December 31, 2005, 2004, 2003, 2002, 2001 and 2000 is found under the heading "Six-Year Financial Highlights" on pages 115 and 116 of this Annual Report.

## GLOSSARY OF TERMS

| | |
|---|---|
| AcSB | Accounting Standards Board |
| APG | Aboriginal Pipeline Group/Mackenzie Valley Aboriginal Pipeline Limited Partnership |
| Bcf | Billion cubic feet |
| B.C. | British Columbia |
| Bcf/d | Billion cubic feet per day |
| Boston Edison | Boston Edison Company |
| BPC | BPC Generation Infrastructure Trust |
| Broadwater | Broadwater Energy project |
| Bruce A | Bruce Power A L.P. |
| Bruce B | Bruce Power L.P. |
| Bruce Power | Bruce A and Bruce B, collectively |
| Calpine | Calpine Corporation and certain of its subsidiaries |
| Cameco | Cameco Corporation |
| CAPP | Canadian Association of Petroleum Producers |
| Cartier Wind | Cartier Wind Energy |
| CBM | Coalbed methane |
| CFE | Comisión Federal de Electricdad |
| CICA | Canadian Institute of Chartered Accountants |
| CPPL | ConocoPhillips Pipe Line Company |
| CrossAlta | CrossAlta Gas Storage & Services Ltd. |
| DBRS | Dominion Bond Rating Service Limited |
| Debentures | Senior Unsecured Debentures |
| disclosure controls | Disclosure controls and procedures |
| EPCOR | EPCOR Utilities Inc. |
| EUB | Alberta Energy and Utilities Board |
| FERC | Federal Energy Regulatory Commission |
| Foothills | Foothills Pipe Lines Ltd. |
| FT | Firm transportation |
| GAAP | Generally accepted accounting principles |
| Gas Pacifico | Gasoducto del Pacifico |
| GCOC | Generic cost of capital |
| GJ | Gigajoules |
| GRA | General Rate Application |
| Great Lakes | Great Lakes Gas Transmission System |
| GTN | Gas Transmission Northwest System and the North Baja System, collectively |
| GTNC | Gas Transmission Northwest Corporation |
| GUA | Gas Utilities Act (Alberta) |
| GWh | Gigawatt hours |
| Hydro-Québec | Hydro-Québec Distribution |
| IID | Imperial Irrigation District |
| INNERGY | INNERGY Holdings S.A. |
| Iroquois | Iroquois Gas Transmission System |
| Irving | Irving Oil |
| Keystone pipeline | Keystone oil pipeline |
| km | Kilometres |
| LNG | Liquefied natural gas |
| Millennium | Millennium Pipeline Project |
| mmcf/d | Million cubic feet per day |
| Moody's | Moody's Investors Service |
| MOU | Memorandum of Understanding |
| MW | Megawatt |
| MWh | Megawatt hour |
| NEB | National Energy Board |
| Net earnings | Net income from continuing operations |
| Northern Border | Northern Border Pipeline Company |
| NPA | Northern Pipeline Act |
| OM&A | Operating, maintenance and administration |
| OPA | Ontario Power Authority |
| OSP | Ocean State Power |
| PG&E | Pacific Gas & Electric Company |
| Paiton Energy | P.T. Paiton Energy Company |
| PipeLines LP | TC PipeLines, LP |
| PJ | Petajoules |
| Portland | Portland Natural Gas Transmission System |
| Portlands Energy | Portlands Energy Centre L.P. |
| Power LP | TransCanada Power, L.P. |
| PPA | Power purchase arrangement |
| ROE | Rate of return on common equity |
| SFAS | Statement of Financial Accounting Standards |
| Shell | Shell US Gas & Power LLC |
| STFT | Short-term firm transportation service |
| TC Hydro | Hydroelectric generation assets acquired from USGen |
| Tcf | Trillion cubic feet |
| TCPL | TransCanada PipeLines Limited |
| TCPM | TransCanada Power Marketing Limited |
| TQM | Trans Québec & Maritimes System |
| TransCanada or the company | TransCanada Corporation |
| TransGas | TransGas de Occidente S.A. |
| Tuscarora | Tuscarora Gas Transmission System |
| U.S. | United States |
| USGen | USGen New England |
| Ventures LP | TransCanada Pipeline Ventures Limited Partnership |
| WCSB | Western Canada Sedimentary Basin |

# Report of Management

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

Management has prepared Management's Discussion and Analysis which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2005 to 2004 and should be read in conjunction with the consolidated financial statements and accompanying notes. In addition, significant changes between 2004 and 2003 are highlighted.

Management has developed and maintains a system of internal accounting controls, including a program of internal audits. Management believes that these 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 of unrelated, non-management directors which meets at least five times during the year with Management and independently with each of the internal and external auditors and as a group to review any significant accounting, internal control and auditing matters. The Audit Committee reviews the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The internal and external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, KPMG LLP, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, 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 cash flows in accordance with Canadian GAAP. The report of KPMG LLP on page 75 outlines the scope of their examination and their opinion on the consolidated financial statements.

**Harold N. Kvisle**
President and
Chief Executive Officer

**Russell K. Girling**
Executive Vice-President, Corporate Development,
and Chief Financial Officer

February 27, 2006

# Auditors' Report

**To the Shareholders of TransCanada Corporation**

We have audited the consolidated balance sheets of TransCanada Corporation as at December 31, 2005 and 2004 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2005. 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 Canadian 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, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 27, 2006

**TRANSCANADA CORPORATION**
## CONSOLIDATED INCOME

| *Year ended December 31* *(millions of dollars except per share amounts)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Revenues** | **6,124** | 5,497 | 5,636 |
| **Operating Expenses** | | | |
| Cost of sales | **1,168** | 940 | 979 |
| Other costs and expenses | **1,889** | 1,615 | 1,666 |
| Depreciation | **1,017** | 948 | 917 |
| | **4,074** | 3,503 | 3,562 |
| **Operating Income** | **2,050** | 1,994 | 2,074 |
| **Other Expenses/(Income)** | | | |
| Financial charges (Note 9) | **836** | 858 | 878 |
| Financial charges of joint ventures (Note 10) | **66** | 63 | 80 |
| Equity income (Note 7) | **(247)** | (213) | (206) |
| Interest income and other | **(63)** | (59) | (60) |
| Gains on sale of assets (Note 8) | **(445)** | (204) | – |
| | **147** | 445 | 692 |
| **Income from Continuing Operations before Income Taxes and Non-Controlling Interests** | **1,903** | 1,549 | 1,382 |
| **Income Taxes (Note 17)** | | | |
| Current | **550** | 414 | 284 |
| Future | **60** | 77 | 230 |
| | **610** | 491 | 514 |
| **Non-Controlling Interests (Note 14)** | **84** | 78 | 67 |
| **Net Income from Continuing Operations** | **1,209** | 980 | 801 |
| **Net Income from Discontinued Operations (Note 23)** | **–** | 52 | 50 |
| **Net Income** | **1,209** | 1,032 | 851 |
| **Net Income Per Share (Note 15)** | | | |
| Basic | | | |
| Continuing operations | **$2.49** | $2.02 | $1.66 |
| Discontinued operations | **–** | 0.11 | 0.10 |
| | **$2.49** | $2.13 | $1.76 |
| Diluted | | | |
| Continuing operations | **$2.47** | $2.01 | $1.66 |
| Discontinued operations | **–** | 0.11 | 0.10 |
| | **$2.47** | $2.12 | $1.76 |

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

**TRANSCANADA CORPORATION**
**CONSOLIDATED CASH FLOWS**

| *Year ended December 31* *(millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Cash Generated from Operations** | | | |
| Net income from continuing operations | **1,209** | 980 | 801 |
| Depreciation | **1,017** | 948 | 917 |
| Gains on sale of assets, net of current tax (Note 8) | **(318)** | (204) | – |
| Equity income in excess of distributions received (Note 7) | **(71)** | (113) | (117) |
| Future income taxes | **60** | 77 | 230 |
| Non-controlling interests | **84** | 78 | 67 |
| Funding of employee future benefits in excess of expense | **(9)** | (29) | (65) |
| Other | **(21)** | (34) | (11) |
| Funds generated from operations | **1,951** | 1,703 | 1,822 |
| (Increase)/decrease in operating working capital (Note 21) | **(49)** | 29 | 93 |
| Net cash provided by operations | **1,902** | 1,732 | 1,915 |
| **Investing Activities** | | | |
| Capital expenditures | **(754)** | (530) | (395) |
| Acquisitions, net of cash acquired (Note 8) | **(1,317)** | (1,516) | (570) |
| Disposition of assets, net of current tax (Note 8) | **671** | 410 | – |
| Deferred amounts and other | **64** | (12) | (131) |
| Net cash used in investing activities | **(1,336)** | (1,648) | (1,096) |
| **Financing Activities** | | | |
| Dividends on common shares | **(586)** | (552) | (510) |
| Distributions paid to non-controlling interests | **(74)** | (87) | (79) |
| Notes payable issued/(repaid), net | **416** | 179 | (62) |
| Long-term debt issued | **799** | 1,090 | 930 |
| Reduction of long-term debt | **(1,113)** | (1,005) | (753) |
| Long-term debt of joint ventures issued | **38** | 217 | 60 |
| Reduction of long-term debt of joint ventures | **(80)** | (112) | (72) |
| Common shares issued (Note 15) | **44** | 32 | 65 |
| Partnership units of joint ventures issued | **–** | 88 | – |
| Redemption of junior subordinated debentures | **–** | – | (218) |
| Net cash used in financing activities | **(556)** | (150) | (639) |
| **Effect of Foreign Exchange Rate Changes on Cash and Short-Term Investments** | **11** | (87) | (54) |
| **Increase/(Decrease) in Cash and Short-Term Investments** | **21** | (153) | 126 |
| **Cash and Short-Term Investments** | | | |
| Beginning of year | **191** | 344 | 218 |
| **Cash and Short-Term Investments** | | | |
| End of year | **212** | 191 | 344 |

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

**TRANSCANADA CORPORATION**
## CONSOLIDATED BALANCE SHEET

| *December 31*<br>*(millions of dollars)* | 2005 | 2004 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and short-term investments | **212** | 191 |
| Accounts receivable | **796** | 616 |
| Inventories | **281** | 174 |
| Other | **277** | 120 |
| | **1,566** | 1,101 |
| **Long-Term Investments (Note 7)** | **400** | 1,098 |
| **Plant, Property and Equipment (Notes 4, 9 and 10)** | **20,038** | 18,764 |
| **Other Assets (Note 5)** | **2,109** | 1,459 |
| | **24,113** | 22,422 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Notes payable (Note 18) | **962** | 546 |
| Accounts payable | **1,494** | 1,135 |
| Accrued interest | **222** | 214 |
| Current portion of long-term debt (Note 9) | **393** | 774 |
| Current portion of long-term debt of joint ventures (Note 10) | **41** | 85 |
| | **3,112** | 2,754 |
| **Deferred Amounts (Note 11)** | **1,196** | 783 |
| **Future Income Taxes (Note 17)** | **703** | 509 |
| **Long-Term Debt (Note 9)** | **9,640** | 9,749 |
| **Long-Term Debt of Joint Ventures (Note 10)** | **937** | 808 |
| **Preferred Securities (Note 13)** | **536** | 554 |
| | **16,124** | 15,157 |
| **Non-Controlling Interests (Note 14)** | **783** | 700 |
| **Shareholders' Equity** | | |
| Common shares (Note 15) | **4,755** | 4,711 |
| Contributed surplus | **272** | 270 |
| Retained earnings | **2,269** | 1,655 |
| Foreign exchange adjustment (Note 16) | **(90)** | (71) |
| | **7,206** | 6,565 |
| **Commitments, Contingencies and Guarantees (Note 22)** | | |
| | **24,113** | 22,422 |

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

On behalf of the Board:

**Harold N. Kvisle**
Director

Harry G Schaefer

**Harry G. Schaefer**
Director

**TRANSCANADA CORPORATION**
## CONSOLIDATED RETAINED EARNINGS

| *Year ended December 31* *(millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Balance at beginning of year | **1,655** | 1,185 | 854 |
| Net income | **1,209** | 1,032 | 851 |
| Common share dividends | **(595)** | (562) | (520) |
| | **2,269** | 1,655 | 1,185 |

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

**TRANSCANADA CORPORATION**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

TransCanada Corporation (the Company or TransCanada) is a leading North American energy company. TransCanada operates in two business segments, Gas Transmission and Power, each of which offers different products and services.

*Gas Transmission*
The Gas Transmission segment owns and operates the following natural gas pipelines:

- a natural gas transmission system extending from the Alberta border east into Québec (the Canadian Mainline);
- a natural gas transmission system in Alberta (the Alberta System);
- a natural gas transmission system extending from the British Columbia/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (the Gas Transmission Northwest System);
- a natural gas transmission system extending from central Alberta to the B.C./United States border and to the Saskatchewan/ U.S. border (the Foothills System);
- a natural gas transmission system extending from the Alberta border west into southeastern B.C. (the BC System);
- a natural gas transmission system extending from a point near Ehrenberg, Arizona to the Baja California, Mexico/California border (the North Baja System); and
- natural gas transmission systems in Alberta which supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP).

Gas Transmission also holds the Company's investments in other natural gas pipelines and natural gas storage facilities located primarily in North America. In addition, Gas Transmission investigates and develops new natural gas and crude oil transmission, natural gas storage and liquefied natural gas regasification facilities in North America.

*Power*
The Power segment builds, owns and operates electrical power generation plants, and sells electricity. Power also holds the Company's investments in other electrical power generation plants. This business operates in Canada and the U.S. as follows:

TransCanada owns and operates:

- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle Ocean State Power (OSP) plant in Burrillville, Rhode Island;
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- the Grandview natural gas-fired cogeneration plant near Saint John, New Brunswick; and
- a waste-heat fuelled cogeneration power plant at the Cancarb facility in Medicine Hat, Alberta.

TransCanada owns but does not operate:

- a 47.9 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce Power A L.P. (Bruce A) and Bruce Power L.P. (Bruce B), respectively (collectively Bruce Power), located near Lake Huron, Ontario.

TransCanada has long-term power purchase arrangements (PPAs) in place for:

- 100 per cent of the production of the Sundance A and 50 per cent, through a partnership, of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 100 per cent of the production of the Sheerness power facility near Hanna, Alberta.

TransCanada has under construction:

- the Bécancour natural gas-fired cogeneration plant near Trois-Rivières, Québec; and
- six Cartier Wind Energy projects in Québec, owned 62 per cent by TransCanada.

## NOTE 1 ACCOUNTING POLICIES

The consolidated financial statements of the Company have been prepared by Management in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. In the opinion of Management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

### Basis of Presentation

The consolidated financial statements include the accounts of TransCanada Corporation and its subsidiaries as well as its proportionate share of the accounts of its joint ventures. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

### Regulation

The Canadian Mainline, the BC System, the Foothills System and Trans Québec & Maritimes Pipeline Inc. (Trans Québec & Maritimes) are subject to the authority of the National Energy Board (NEB) and the Alberta System is regulated by the Alberta Energy and Utilities Board (EUB). The Gas Transmission Northwest System, the North Baja System and the other natural gas pipelines in the U.S. are subject to the authority of the Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to the determination of revenues, tolls, construction and operations. In order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls, and to thereby achieve a proper matching of revenues and expenses, the timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP. The impact of rate regulation on TransCanada is provided in Note 12.

### Revenue Recognition

*Gas Transmission*

In the Gas Transmission business, revenues from the Canadian rate-regulated operations are recognized in accordance with the decisions made by the NEB and EUB. Revenues from the U.S. rate-regulated operations are recorded in accordance with FERC rules and regulations. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

*Power*

The majority of revenues from the Power business are derived from the sale of electricity from energy marketing and trading activities and are recorded in the month of delivery. Revenues from the Power business are also derived from the sale of unutilized natural gas fuel and energy derivative contracts, including financial swaps, futures contracts and options.

### Dilution Gains

Dilution gains which result from the sale of units by limited partnerships in which TransCanada has an ownership interest are recognized immediately in net income.

### Cash and Short-Term Investments

The Company's short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

### Inventories

Inventories consisting of natural gas in storage, uranium, materials and supplies, including spare parts, are carried at the lower of average cost or net realizable value.

### Plant, Property and Equipment

*Gas Transmission*

Plant, property and equipment of natural gas transmission operations are carried at cost. Depreciation is calculated on a straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from two to six per cent and metering and other plant are depreciated at various rates. An allowance for funds used during construction, using the rate of return on rate base approved by the regulators, is capitalized and included in the cost of gas transmission plant.

*Power*

Major power generation plant, equipment and structures in the Power business are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two to ten per cent. Nuclear assets under capital lease are initially recorded at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life or remaining lease term. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives. Interest is capitalized on projects under construction.

*Corporate*

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three to 20 per cent.

## Power Purchase Arrangements

PPAs are long-term contracts to purchase or sell power on a predetermined basis. The initial payments for PPAs acquired by TransCanada are deferred and amortized over the terms of the contracts, from the dates of acquisition, which range from ten to 19 years. Certain PPAs under which TransCanada sells power are accounted for as operating leases and, accordingly, the related plant, property and equipment are accounted for as assets under operating leases.

## Stock Options

TransCanada's Stock Option Plan permits the award of options to purchase the Company's common shares to certain employees, some of whom are officers. The contractual life of options granted subsequent to 2002 is seven years and for options granted prior to 2003, the contractual life is ten years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on each of the three following award date anniversaries. The Company records compensation expense over the three year vesting period. This charge is reflected in the Gas Transmission and Power segments.

## Income Taxes

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian natural gas transmission operations. Under the taxes payable method, it is not necessary to provide for future income taxes. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future taxes payable will be included in future costs of service and recorded in revenues at the time payable. The liability method of accounting for income taxes is used for the remainder of the Company's operations. Under this method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period in which they occur.

Canadian income taxes are not provided on the unremitted earnings of foreign investments which the Company does not intend to repatriate in the foreseeable future.

## Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at period end exchange rates and items included in the statements of consolidated income, consolidated retained earnings and consolidated cash flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in the foreign exchange adjustment in Shareholders' Equity.

Exchange gains or losses on the principal amounts of foreign currency debt and preferred securities related to the Alberta System and the Canadian Mainline are deferred until they are recovered in tolls.

## Derivative Financial Instruments and Hedging Activities

The Company utilizes derivative and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices.

Derivatives and other instruments must be designated and effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow and fair value hedges, gains or losses relating to derivatives are deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. For hedges of net investments in self-sustaining foreign operations, exchange gains or losses on derivatives, net of tax, and designated foreign currency denominated debt are offset against the exchange losses or gains arising on the translation of the financial statements of the foreign operations included in the foreign exchange adjustment account in Shareholders' Equity. In the event that a derivative does not meet the designation or effectiveness criteria, realized and unrealized gains or losses are recognized in income each period in the same financial statement category as the underlying transaction giving rise to the exposure being economically hedged. Premiums paid or received with respect to derivatives that are hedges are deferred and amortized to income over the term of the hedge.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related deferred gains or losses are recognized in income in the current period.

The recognition of gains and losses on derivatives for Canadian Mainline, Alberta System, the BC System and the Foothills System exposures is determined through the regulatory process.

### Asset Retirement Obligation

The Company recognizes the fair value of a liability for an asset retirement obligation, where a legal obligation exists, in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted at the end of each period through charges to operating expenses.

### Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans). The cost of defined benefit pensions and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market-related values based on a five-year moving average value for all plan assets. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has broad-based, medium-term employee incentive plans, which grant units to each eligible employee and are payable in cash at the date of vesting. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, units vest when certain conditions are met, including the employee's continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans and other post-employment benefit plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

## NOTE 2 ACCOUNTING CHANGES

### Financial Instruments – Disclosure and Presentation

Effective January 1, 2005, the Company adopted the amendment of the Canadian Institute of Chartered Accountants (CICA) to the existing Handbook Section "Financial Instruments – Disclosure and Presentation", which provides guidance for classifying certain financial instruments that embody obligations that may be settled by issuance of the issuer's equity shares as debt when the instrument does not establish an ownership relationship. In accordance with this amendment, TransCanada reclassified the non-controlling interest component of preferred securities as long-term debt.

This accounting change was applied retroactively with restatement of prior periods. The impact of this change on TransCanada's net income in prior years was nil.

The impact of the accounting change on the Company's consolidated balance sheet as at December 31, 2004 is as follows.

| *(millions of dollars)* | Increase/(Decrease) |
|---|---|
| Deferred amounts[(1)] | 135 |
| Preferred securities | 535 |
| Non-controlling interest | |
| Preferred securities of subsidiary | (670) |
| Total liabilities and shareholders' equity | – |

(1) Regulatory deferral.

### Limited Partnerships

A wholly-owned subsidiary of TransCanada serves as the general partner of TC PipeLines, LP (PipeLines LP). Effective December 31, 2005, TransCanada consolidated limited partnerships when the general partner controls the strategic operating, financing and investing activities of the limited partnerships and the limited partners do not have substantive participating rights. This change was applied retroactively. There was no impact on previously recorded net income and the balance sheet and income statement impact was not material.

## NOTE 3 SEGMENTED INFORMATION

### NET INCOME/(LOSS)[1]

| *Year ended December 31, 2005 (millions of dollars)* | Gas Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| Revenues | **4,163** | **1,961** | **–** | **6,124** |
| Cost of sales[2] | **–** | **(1,168)** | **–** | **(1,168)** |
| Other costs and expenses | **(1,380)** | **(505)** | **(4)** | **(1,889)** |
| Depreciation | **(938)** | **(79)** | **–** | **(1,017)** |
| Operating income/(loss) | **1,845** | **209** | **(4)** | **2,050** |
| Financial charges and non-controlling interests | **(788)** | **(2)** | **(130)** | **(920)** |
| Financial charges of joint ventures | **(57)** | **(9)** | **–** | **(66)** |
| Equity income | **79** | **168** | **–** | **247** |
| Interest income and other | **25** | **5** | **33** | **63** |
| Gains on sale of assets | **82** | **363** | **–** | **445** |
| Income taxes | **(502)** | **(173)** | **65** | **(610)** |
| Net income from continuing operations | **684** | **561** | **(36)** | **1,209** |
| Net income from discontinued operations | | | | **–** |
| **Net Income** | | | | **1,209** |

| *Year ended December 31, 2004 (millions of dollars)* | Gas Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| Revenues | 3,929 | 1,568 | – | 5,497 |
| Cost of sales[2] | – | (940) | – | (940) |
| Other costs and expenses | (1,228) | (384) | (3) | (1,615) |
| Depreciation | (876) | (72) | – | (948) |
| Operating income/(loss) | 1,825 | 172 | (3) | 1,994 |
| Financial charges and non-controlling interests | (848) | (9) | (79) | (936) |
| Financial charges of joint ventures | (59) | (4) | – | (63) |
| Equity income | 83 | 130 | – | 213 |
| Interest income and other | 8 | 14 | 37 | 59 |
| Gains on sale of assets | 7 | 197 | – | 204 |
| Income taxes | (430) | (104) | 43 | (491) |
| Net income from continuing operations | 586 | 396 | (2) | 980 |
| Net income from discontinued operations | | | | 52 |
| **Net Income** | | | | 1,032 |

| *Year ended December 31, 2003 (millions of dollars)* | Gas Transmission | Power | Corporate | Total |
|---|---|---|---|---|
| Revenues | 3,968 | 1,668 | – | 5,636 |
| Cost of sales[2] | – | (979) | – | (979) |
| Other costs and expenses | (1,274) | (385) | (7) | (1,666) |
| Depreciation | (834) | (82) | (1) | (917) |
| Operating income/(loss) | 1,860 | 222 | (8) | 2,074 |
| Financial charges and non-controlling interests | (845) | (11) | (89) | (945) |
| Financial charges of joint ventures | (79) | (1) | – | (80) |
| Equity income | 107 | 99 | – | 206 |
| Interest income and other | 17 | 14 | 29 | 60 |
| Income taxes | (438) | (103) | 27 | (514) |
| Net income from continuing operations | 622 | 220 | (41) | 801 |
| Net income from discontinued operations | | | | 50 |
| **Net Income** | | | | 851 |

[1] In determining the net income of each segment, certain expenses such as indirect financial charges and related income taxes are not allocated to business segments.

[2] Cost of sales is comprised of commodity purchases for resale.

### TOTAL ASSETS

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Gas Transmission | **18,252** | 18,720 |
| Power | **4,923** | 2,802 |
| Corporate | **938** | 900 |
| | **24,113** | 22,422 |

### GEOGRAPHIC INFORMATION

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Revenues**[3] | | | |
| Canada – domestic | **3,499** | 3,214 | 3,324 |
| Canada – export | **1,160** | 1,261 | 1,293 |
| United States | **1,465** | 1,022 | 1,019 |
| | **6,124** | 5,497 | 5,636 |

(3) Revenues are attributed to countries based on country of origin of product or service.

### PLANT, PROPERTY AND EQUIPMENT

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Canada | **15,647** | 14,757 |
| United States | **4,306** | 4,007 |
| Mexico | **85** | – |
| | **20,038** | 18,764 |

### CAPITAL EXPENDITURES

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Gas Transmission | **377** | 241 | 260 |
| Power | **373** | 285 | 132 |
| Corporate | **4** | 4 | 3 |
| | **754** | 530 | 395 |

## NOTE 4 PLANT, PROPERTY AND EQUIPMENT

| December 31 (millions of dollars) | 2005 Cost | 2005 Accumulated Depreciation | 2005 Net Book Value | 2004 Cost | 2004 Accumulated Depreciation | 2004 Net Book Value |
|---|---|---|---|---|---|---|
| **Gas Transmission** | | | | | | |
| Canadian Mainline | | | | | | |
| Pipeline | **8,701** | **3,665** | **5,036** | 8,695 | 3,421 | 5,274 |
| Compression | **3,341** | **1,066** | **2,275** | 3,322 | 947 | 2,375 |
| Metering and other | **359** | **134** | **225** | 366 | 125 | 241 |
| | **12,401** | **4,865** | **7,536** | 12,383 | 4,493 | 7,890 |
| Under construction | **15** | **–** | **15** | 16 | – | 16 |
| | **12,416** | **4,865** | **7,551** | 12,399 | 4,493 | 7,906 |
| Alberta System | | | | | | |
| Pipeline | **5,020** | **2,203** | **2,817** | 4,978 | 2,055 | 2,923 |
| Compression | **1,493** | **676** | **817** | 1,496 | 599 | 897 |
| Metering and other | **799** | **247** | **552** | 861 | 262 | 599 |
| | **7,312** | **3,126** | **4,186** | 7,335 | 2,916 | 4,419 |
| Under construction | **25** | **–** | **25** | 20 | – | 20 |
| | **7,337** | **3,126** | **4,211** | 7,355 | 2,916 | 4,439 |
| GTN(1) | | | | | | |
| Pipeline | **1,381** | **60** | **1,321** | 1,417 | 8 | 1,409 |
| Compression | **507** | **15** | **492** | 526 | 2 | 524 |
| Metering and other | **90** | **–** | **90** | 101 | 2 | 99 |
| | **1,978** | **75** | **1,903** | 2,044 | 12 | 2,032 |
| Under construction | **18** | **–** | **18** | 17 | – | 17 |
| | **1,996** | **75** | **1,921** | 2,061 | 12 | 2,049 |
| Foothills System | | | | | | |
| Pipeline | **815** | **377** | **438** | 815 | 346 | 469 |
| Compression | **373** | **128** | **245** | 373 | 114 | 259 |
| Metering and other | **75** | **31** | **44** | 78 | 35 | 43 |
| | **1,263** | **536** | **727** | 1,266 | 495 | 771 |
| Joint Ventures and other(2) | **3,491** | **1,127** | **2,364** | 3,293 | 1,073 | 2,220 |
| | **26,503** | **9,729** | **16,774** | 26,374 | 8,989 | 17,385 |
| **Power**(3) | | | | | | |
| Nuclear(4) | **1,265** | **143** | **1,122** | | | |
| Natural gas | **1,121** | **347** | **774** | 1,333 | 374 | 959 |
| Hydro | **598** | **9** | **589** | 61 | 1 | 60 |
| Other | **67** | **36** | **31** | 67 | 32 | 35 |
| | **3,051** | **535** | **2,516** | 1,461 | 407 | 1,054 |
| Under construction | **721** | **–** | **721** | 288 | – | 288 |
| | **3,772** | **535** | **3,237** | 1,749 | 407 | 1,342 |
| **Corporate** | **73** | **46** | **27** | 124 | 87 | 37 |
| | **30,348** | **10,310** | **20,038** | 28,247 | 9,483 | 18,764 |

(1) Gas Transmission Northwest System and North Baja System (collectively GTN).

(2) The December 31, 2005 net book value includes $235 million of plant, property and equipment under construction (2004 – $20 million).

(3) Certain Power generation facilities are accounted for as assets under operating leases. At December 31, 2005, the net book value of these facilities was $87 million (2004 – $70 million). In 2005, revenues of $23 million (2004 – $7 million) were recognized through the sale of electricity under the related PPAs.

(4) Assets under capital lease relating to Bruce Power. The Company proportionately consolidated its ownership interest in Bruce Power, on a prospective basis, effective October 31, 2005.

## NOTE 5 OTHER ASSETS

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Derivative contracts | **209** | 180 |
| Hedging deferrals | **118** | 50 |
| PPAs – Canada[1] | **825** | 274 |
| PPAs – U.S.[1] | **–** | 98 |
| Pension and other benefit plans | **304** | 253 |
| Regulatory assets | **183** | 174 |
| Loans and advances[2] | **91** | 135 |
| Goodwill | **57** | 58 |
| Debt issue costs | **48** | 50 |
| Other | **274** | 187 |
| | **2,109** | 1,459 |

(1) The following amounts related to the PPAs are included in the consolidated financial statements.

| | **2005** | | | 2004 | | |
|---|---|---|---|---|---|---|
| *December 31 (millions of dollars)* | **Cost** | **Accumulated Amortization** | **Net Book Value** | Cost | Accumulated Amortization | Net Book Value |
| PPAs – Canada | **915** | **90** | **825** | 345 | 71 | 274 |
| PPAs – U.S. | **–** | **–** | **–** | 102 | 4 | 98 |

The aggregate amortization expense with respect to the PPAs was $24 million for the year ended December 31, 2005 (2004 – $24 million; 2003 – $37 million). The amortization expense with respect to the PPAs approximates: 2006 – $58 million; 2007 – $58 million; 2008 – $58 million; 2009 – $58 million; and 2010 – $58 million. In August 2005, the Company sold TransCanada Power, L.P. (Power LP), which included 100 per cent of the PPAs – U.S. Effective December 31, 2005, the Company acquired the remaining rights and obligations for the remaining 15 years of the Sheerness PPA for $585 million.

(2) The December 31, 2004 balance includes a $75 million unsecured note receivable from Bruce B bearing interest at 10.5 per cent per annum, due February 14, 2008. Effective October 31, 2005, the Company proportionately consolidated its investment in Bruce B and this balance is eliminated upon consolidation. The December 31, 2005 balance includes an $87 million loan (2004 – $60 million) to the Aboriginal Pipeline Group (APG) to finance the APG for its one-third share of project development costs related to the Mackenzie Gas Pipeline Project.

## NOTE 6 JOINT VENTURE INVESTMENTS

| | | TransCanada's Proportionate Share | | | | |
|---|---|---|---|---|---|---|
| | | Income Before Income Taxes Year Ended December 31 | | | Net Assets December 31 | |
| *(millions of dollars)* | Ownership Interest | **2005** | 2004 | 2003 | **2005** | 2004 |
| **Gas Transmission** | | | | | | |
| Great Lakes | 50.0%[1] | **73** | 86 | 81 | **375** | 379 |
| Iroquois | 44.5%[1][2] | **29** | 28 | 31 | **190** | 175 |
| Trans Québec & Maritimes | 50.0% | **13** | 13 | 14 | **73** | 75 |
| CrossAlta | 60.0%[1] | **31** | 20 | 11 | **30** | 24 |
| Foothills | [3] | **–** | – | 19 | **–** | – |
| Other | Various | **15** | 12 | 12 | **67** | 67 |
| **Power** | | | | | | |
| Bruce A | 47.9%[4] | **19** | | | **563** | |
| Bruce B | 31.6%[4] | **5** | | | **434** | |
| ASTC Power Partnership | 50.0%[5] | **–** | – | – | **88** | 93 |
| Power LP | [6] | **25** | 32 | 25 | **–** | 289 |
| | | **210** | 191 | 193 | **1,820** | 1,102 |

(1) Great Lakes Gas Transmission Limited Partnership (Great Lakes); Iroquois Gas Transmission System, L.P. (Iroquois); CrossAlta Gas Storage & Services Ltd. (CrossAlta).

(2) In June 2005, the Company acquired an additional 3.5 per cent ownership interest in Iroquois.

(3) In August 2003, the Company acquired the remaining interests in Foothills Pipe Lines Ltd. and its subsidiaries (Foothills) previously not held by TransCanada, and Foothills was consolidated subsequent to that date.

(4) TransCanada acquired a 47.4 per cent ownership interest in Bruce A on October 31, 2005 and a 31.6 per cent ownership interest in Bruce B in February 2003. The Company increased its ownership interest in Bruce A to 47.9 per cent during the remainder of 2005 as a result of certain other partners not participating in capital contributions to Bruce A. The Company proportionately consolidated its investments in Bruce A and Bruce B, on a prospective basis, effective October 31, 2005.

(5) The Company has a 50.0 per cent ownership interest in ASTC Power Partnership, which is located in Alberta and holds a PPA. The underlying power volumes related to the 50.0 per cent ownership interest in the partnership are effectively transferred to TransCanada.

(6) In April 2004, the Company's interest in Power LP decreased to 30.6 per cent from 35.6 per cent. In August 2005, the Company sold its 30.6 per cent interest in Power LP.

Consolidated retained earnings at December 31, 2005 include undistributed earnings from these joint ventures of $765 million (2004 – $473 million).

### Summarized Financial Information of Joint Ventures

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Income** | | | |
| Revenues | **687** | 572 | 635 |
| Other costs and expenses | **(328)** | (240) | (278) |
| Depreciation | **(93)** | (90) | (98) |
| Financial charges and other | **(56)** | (51) | (66) |
| Proportionate share of income before income taxes of joint ventures | **210** | 191 | 193 |

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Cash Flows** | | | |
| Operations | **346** | 270 | 259 |
| Investing activities | **(133)** | (287) | (139) |
| Financing activities[1] | **(152)** | 35 | (115) |
| Effect of foreign exchange rate changes on cash and short-term investments | **(1)** | (5) | (12) |
| Proportionate share of increase/(decrease) in cash and short-term investments of joint ventures | **60** | 13 | (7) |

(1) Financing activities include cash outflows resulting from distributions paid to TransCanada of $201 million (2004 – $158 million; 2003 – $103 million), and cash inflows resulting from capital contributions paid by TransCanada of $92 million (2004 and 2003 – nil).

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| **Balance Sheet** | | |
| Cash and short-term investments | **123** | 63 |
| Other current assets | **281** | 122 |
| Plant, property and equipment | **2,707** | 1,708 |
| Current liabilities | **(291)** | (155) |
| (Deferred amounts)/other assets (net) | **(45)** | 221 |
| Long-term debt of joint ventures | **(937)** | (808) |
| Future income taxes | **(18)** | (49) |
| Proportionate share of net assets of joint ventures | **1,820** | 1,102 |

## NOTE 7 LONG-TERM INVESTMENTS

| | | TransCanada's Share | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Distributions from Equity Investments Year Ended December 31 | | | Income from Equity Investments Year Ended December 31 | | | Equity Investments December 31 | |
| *(millions of dollars)* | Ownership Interest | **2005** | 2004 | 2003 | **2005** | 2004 | 2003 | **2005** | 2004 |
| **Gas Transmission** | | | | | | | | | |
| Northern Border | (1) | **76** | 79 | 65 | **61** | 65 | 63 | **315** | 349 |
| TransGas | 46.5% (2) | **6** | 8 | 8 | **11** | 11 | 27 | **62** | 78 |
| Portland | 61.7% (3) | **–** | – | 10 | **–** | – | 14 | **–** | – |
| Other | Various | **10** | 13 | 6 | **7** | 7 | 3 | **23** | 29 |
| **Power** | | | | | | | | | |
| Bruce B | 31.6% (4) | **84** | – | – | **168** | 130 | 99 | **–** | 642 |
| | | **176** | 100 | 89 | **247** | 213 | 206 | **400** | 1,098 |

(1) The Company consolidates PipeLines LP, which holds a 30.0 per cent interest in Northern Border Pipeline Company (Northern Border). The amounts presented represent a 30.0 per cent interest, however, the Company's effective ownership interest in Northern Border, net of non-controlling interests, is 4.0 per cent as a result of the Company holding a 13.4 per cent interest in PipeLines LP. The Company's effective ownership interest in Northern Border was reduced from 10.0 per cent to 4.0 per cent in a series of transactions related to PipeLines LP in March and April 2005.

(2) TransGas de Occidente S.A. (TransGas).

(3) In September 2003, the Company increased its ownership interest in Portland Natural Gas Transmission System Partnership (Portland) to 43.4 per cent from 33.3 per cent. In December 2003, the Company increased its ownership interest to 61.7 per cent and the investment was fully consolidated subsequent to that date.

(4) The Company proportionately consolidated its 31.6 per cent ownership interest in Bruce B, on a prospective basis, effective October 31, 2005.

Consolidated retained earnings at December 31, 2005 include undistributed earnings from these equity investments of $55 million (2004 – $294 million).

## NOTE 8 ACQUISITIONS AND DISPOSITIONS

### Acquisitions

*Sheerness PPA*
Effective December 31, 2005, TransCanada acquired the remaining rights and obligations of the Sheerness PPA from the Alberta Balancing Pool for $585 million. There is approximately a 15 year term remaining on the PPA.

*Bruce Power*
In February 2003, the Company acquired a 31.6 per cent partnership interest in Bruce B for $409 million, which at that time owned the currently idle Bruce A Units 1 and 2 as well as the currently operating Bruce A Units 3 and 4 and Bruce B Units 5 to 8. The Company accounted for this as an equity investment. On October 31, 2005, as part of an agreement to restart the currently idle Bruce A Units 1 and 2, TransCanada acquired a partnership interest in a newly created partnership, Bruce A, which subleased the Bruce A Units 1 to 4 from Bruce B (the Bruce A Sublease) and purchased certain other related assets. TransCanada incurred a net cash outlay of $100 million as a result of this transaction and as at December 31, 2005 held a 47.9 per cent interest in Bruce A. As part of this reorganization, both Bruce A and Bruce B became jointly controlled entities and TransCanada commenced proportionately consolidating its investments in both Bruce A and Bruce B, on a prospective basis, effective October 31, 2005.

*TC Hydro*
In April 2005, TransCanada acquired certain hydroelectric generation assets from USGen New England, Inc. for approximately US$503 million. Substantially all of the purchase price was allocated to plant, property and equipment. The financial results from these assets have been included in the Power segment as of the date of acquisition.

*GTN*

In November 2004, TransCanada acquired GTN for US$1,728 million, including US$528 million of assumed debt and closing adjustments. The purchase price was allocated as follows using fair values of the net assets at the date of acquisition.

**Purchase Price Allocation**

| *(millions of U.S. dollars)* | |
|---|---|
| Current assets | 40 |
| Plant, property and equipment | 1,718 |
| Other non-current assets | 21 |
| Goodwill | 48 |
| Current liabilities | (48) |
| Long-term debt | (528) |
| Other non-current liabilities | (51) |
| | 1,200 |

Goodwill, which is attributable to the North Baja System, is re-evaluated on an annual basis for impairment. Factors that contributed to goodwill include opportunities for expansion, a strong competitive position, strong demand for natural gas in the western markets and access to an ample supply of relatively low-cost natural gas. The goodwill recognized on this transaction is being amortized for tax purposes over 15 years.

The acquisition was accounted for using the purchase method of accounting. The financial results of GTN were consolidated with those of TransCanada subsequent to the acquisition date and included in the Gas Transmission segment.

**Dispositions**

The pre-tax gains on sale of assets are comprised of the following.

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Gains related to Power LP | **245** | 197 |
| Gain on sale of Paiton Energy[(1)] | **118** | – |
| Gain on sale of PipeLines LP units | **82** | – |
| Gain on sale of Millennium[(1)] | **–** | 7 |
| | **445** | 204 |

(1) PT Paiton Energy Company (Paiton Energy); Millennium Pipeline project (Millennium).

*Power LP*

In August 2005, TransCanada sold its ownership interest in Power LP to EPCOR Utilities Inc. (EPCOR) for net proceeds of $523 million and realized an after-tax gain of $193 million. The net gain was recorded in the Power segment and the Company recorded a $52 million income tax charge, including $79 million of current income tax expense, on this transaction. The book value of Power LP's assets and liabilities disposed of under this sale were $452 million and $174 million, respectively. EPCOR's acquisition included 14.5 million limited partnership units of Power LP, representing 30.6 per cent of the outstanding units; 100 per cent ownership of the general partner of Power LP; and the management and operations agreements governing the ongoing operation of Power LP's generation assets.

In April 2004, TransCanada sold the ManChief and Curtis Palmer power facilities to Power LP for US$402.6 million, plus closing adjustments of US$12.8 million, and recognized an after-tax gain on sale of $15 million. The net gain was recorded in the Power segment and the Company recorded a $10 million income tax charge.

At a special meeting held in April 2004, Power LP's unitholders approved an amendment to the terms of the Power LP Partnership Agreement to remove Power LP's obligation to redeem all units not owned by TransCanada at June 30, 2017. TransCanada was required to fund this redemption, thus the removal of Power LP's obligation eliminated this requirement. The removal of the obligation and the reduction in TransCanada's ownership interest in Power LP resulted in a gain of $172 million.

*Paiton Energy*

In November 2005, TransCanada sold its approximate 11 per cent ownership interest in Paiton Energy to subsidiaries of The Tokyo Electric Power Company for gross proceeds of US$103 million ($122 million). The book value of Paiton Energy at the time of sale was nil and TransCanada realized an after-tax gain on sale of $115 million. The net gain was recorded in the Power segment and the Company recorded a $3 million income tax charge, including $3 million of current income tax recovery.

*PipeLines LP*

In March and April 2005, TransCanada sold 3,574,200 common units of PipeLines LP for net proceeds of $153 million and recorded an after-tax gain of $49 million. The net gain was recorded in the Gas Transmission segment and the company recorded a $33 million income tax charge, including $51 million of current income tax expense, on this transaction. Subsequent to these transactions, TransCanada continues to own a 13.4 per cent interest in PipeLines LP represented by a general partner interest of 2.0 per cent and an 11.4 per cent limited partner interest.

## NOTE 9 LONG-TERM DEBT

| | | 2005 | | 2004 | |
|---|---|---|---|---|---|
| | Maturity Dates | Outstanding December 31[1] | Weighted Average Interest Rate[2] | Outstanding December 31[1] | Weighted Average Interest Rate[2] |
| **CANADIAN MAINLINE**[4] | | | | | |
| First Mortgage Pipe Line Bonds | | | | | |
| Pounds Sterling (2005 and 2004 – £25) | 2007 | 50 | 16.5% | 58 | 16.5% |
| Debentures | | | | | |
| Canadian dollars | 2008 to 2020 | 1,354 | 10.9% | 1,354 | 10.9% |
| U.S. dollars (2005 and 2004 – US$600)[3] | 2012 to 2021 | 702 | 9.5% | 722 | 9.5% |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2006 to 2031 | 1,987 | 7.1% | 2,167 | 6.9% |
| U.S. dollars (2005 and 2004 – US$120) | 2010 | 140 | 6.1% | 144 | 6.1% |
| | | 4,233 | | 4,445 | |
| **ALBERTA SYSTEM**[5] | | | | | |
| Debentures and Notes | | | | | |
| Canadian dollars | 2007 to 2024 | 585 | 11.6% | 607 | 11.6% |
| U.S. dollars (2005 and 2004 – US$375) | 2012 to 2023 | 437 | 8.2% | 451 | 8.2% |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2006 to 2030 | 964 | 6.6% | 767 | 7.4% |
| U.S. dollars (2005 and 2004 – US$233) | 2026 to 2029 | 272 | 7.7% | 280 | 7.7% |
| | | 2,258 | | 2,105 | |
| **GTN**[6] | | | | | |
| Unsecured Debentures and Notes (2005 – US$400; 2004 – US$525) | 2010 to 2035 | 466 | 5.3% | 632 | 7.2% |
| **FOOTHILLS SYSTEM**[4] | | | | | |
| Senior Unsecured Notes | 2009 to 2014 | 400 | 4.9% | 400 | 4.9% |
| **PORTLAND**[7] | | | | | |
| Senior Secured Notes | | | | | |
| U.S. dollars (2005 – US$241; 2004 – US$256) | 2018 | 281 | 5.9% | 308 | 5.9% |
| **OTHER** | | | | | |
| Medium-Term Notes[4] | | | | | |
| Canadian dollars | 2014 to 2030 | 542 | 5.9% | 592 | 6.2% |
| U.S. dollars (2005 and 2004 – US$521) | 2006 to 2025 | 607 | 6.9% | 627 | 6.9% |
| Subordinated Debentures[4] | | | | | |
| U.S. dollars (2005 and 2004 – US$57) | 2006 | 66 | 9.1% | 68 | 9.1% |
| Unsecured Loans, Debentures and Notes[3][8] | | | | | |
| U.S. dollars (2005 – US$1,014; 2004 – US$1,119) | 2006 to 2034 | 1,180 | 4.8% | 1,346 | 5.0% |
| | | 2,395 | | 2,633 | |
| | | 10,033 | | 10,523 | |
| Less: Current Portion of Long-Term Debt | | 393 | | 774 | |
| | | 9,640 | | 9,749 | |

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

(2) Weighted average interest rates are stated as at the respective outstanding dates. The effective weighted average interest rates resulting from swap agreements are as follows: Other U.S. dollar subordinated debentures – 9.0 per cent (2004 – 9.0 per cent); and Other U.S. dollar unsecured loans, debentures and notes – 4.9 per cent (2004 – 5.1 per cent).

(3) In 2005, under agreement with shippers, TransCanada PipeLines Limited (TCPL) effectively fixed the exchange rate on the US$600 million debentures for regulatory purposes. The exchange differential on the long-term debt at December 31, 2005, is $(2) million and is included as part of Other U.S. dollar unsecured loans, debentures and notes.

(4) Long-term debt of TCPL.

(5) Long-term debt of NOVA Gas Transmission Ltd. excluding two medium-term notes held by TCPL: a $300 million note (2004 – nil) and a $233 million note (US$200 million) (2004 – $241 million (US$200 million)).

(6) Long-term debt of Gas Transmission Northwest Corporation.

(7) Long-term debt of Portland.

(8) Long-term debt of TCPL, excluding $16 million (2004 – $44 million) issued by PipeLines LP.

### Principal Repayments

Principal repayments on the long-term debt of the Company approximate: 2006 – $393 million; 2007 – $604 million; 2008 – $547 million; 2009 – $742 million; and 2010 – $416 million.

### Debt Shelf Programs

At December 31, 2005, $1.2 billion of medium-term note debentures could be issued under a base shelf program in Canada and US$1 billion of debt securities could be issued under a debt shelf program in the U.S. In January 2006, the Company issued $300 million of five year medium-term notes bearing interest of 4.3 per cent under the Canadian base shelf program.

## CANADIAN MAINLINE

### First Mortgage Pipe Line Bonds

The Deed of Trust and Mortgage securing the Company's First Mortgage Pipe Line Bonds limits the specific and floating charges to those assets comprising the present and future Canadian Mainline and TCPL's present and future gas transportation contracts.

## ALBERTA SYSTEM

### Debentures

Debentures amounting to $225 million have retraction provisions which entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions have been made to December 31, 2005.

### Medium-Term Notes

Medium-term notes amounting to $50 million have a provision entitling the holders to extend the maturity of the medium-term notes from the initial repayment date of 2007 to 2027. If extended, the interest rate would increase from 6.1 per cent to 7.0 per cent and the medium-term notes would become redeemable at the option of the Company.

### Financial Charges

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Interest on long-term debt | **849** | 864 | 867 |
| Interest on short-term debt | **23** | 7 | 16 |
| Capitalized interest | **(24)** | (11) | (9) |
| Amortizations and other financial charges | **(12)** | (2) | 4 |
| | **836** | 858 | 878 |

The Company made interest payments of $838 million for the year ended December 31, 2005 (2004 – $864 million; 2003 – $903 million).

## NOTE 10 LONG-TERM DEBT OF JOINT VENTURES

| | | 2005 | | 2004 | |
|---|---|---|---|---|---|
| | Maturity Dates | **Outstanding December 31[(1)]** | **Weighted Average Interest Rate[(2)]** | Outstanding December 31[(1)] | Weighted Average Interest Rate[(2)] |
| **Great Lakes** | | | | | |
| Senior Unsecured Notes (2005 – US$230; 2004 – US$235) | 2011 to 2030 | **268** | **7.9%** | 283 | 7.9% |
| **Bruce Power** | | | | | |
| Capital Lease Obligations | 2018 | **254** | **7.5%** | | |
| **Iroquois** | | | | | |
| Senior Unsecured Notes (2005 – US $165; 2004 – US$151) | 2010 to 2027 | **192** | **7.5%** | 182 | 7.5% |
| Bank Loan (2005 – US$25; 2004 – US$36) | 2008 | **29** | **4.3%** | 43 | 2.5% |
| **Trans Québec & Maritimes** | | | | | |
| Bonds | 2009 to 2010 | **138** | **6.0%** | 143 | 7.3% |
| Term Loan | 2010 | **29** | **3.5%** | 29 | 3.2% |
| **Power L.P.[(3)]** | | | | | |
| Senior Unsecured Notes (2004 – US$58) | | **–** | | 70 | 5.9% |
| Credit Facility | | **–** | | 64 | 3.2% |
| Term Loan | | **–** | | 2 | 11.3% |
| **Other** | 2006 to 2012 | **68** | **6.1%** | 77 | 5.8% |
| | | **978** | | 893 | |
| Less: Current Portion of Long-Term Debt of Joint Ventures | | **41** | | 85 | |
| | | **937** | | 808 | |

(1) Amounts outstanding represent TransCanada's proportionate share and are stated in millions of Canadian dollars; amounts denominated in U.S. dollars are stated in millions.

(2) Weighted average interest rates are stated as at the respective outstanding dates. At December 31, 2005, the effective weighted average interest rates resulting from swap agreements are as follows: Iroquois bank loan – 5.4 per cent (2004 – 4.1 per cent).

(3) In August 2005, the Company sold its ownership interest in Power LP.

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt by each joint venture is limited to the rights and assets of that joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment.

The Company's proportionate share of principal repayments resulting from maturities and sinking fund obligations of the non-recourse joint venture debt approximates: 2006 – $34 million; 2007 – $20 million; 2008 – $20 million; 2009 – $78 million; and 2010 – $273 million.

The Company's proportionate share of principal payments resulting from the capital lease obligations of Bruce Power approximates: 2006 – $7 million; 2007 – $8 million; 2008 – $9 million; 2009 – $11 million; and 2010 – $13 million.

### Financial Charges of Joint Ventures

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Interest on long-term debt | **60** | 59 | 77 |
| Interest on capital lease obligations | **3** | – | – |
| Interest on short-term debt and other financial charges | **1** | 2 | 1 |
| Deferrals and amortizations | **2** | 2 | 2 |
| | **66** | 63 | 80 |

The Company's proportionate share of the interest payments of joint ventures was $62 million for the year ended December 31, 2005 (2004 – $58 million; 2003 – $71 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $3 million for the year ended December 31, 2005 (2004 and 2003 – nil).

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for renewals commencing January 1, 2019. The first renewal is for a period of one year, and each of the second to thirteenth renewals is for a period of two years.

## NOTE 11 DEFERRED AMOUNTS

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Derivative contracts | **212** | 135 |
| Hedging deferrals | **72** | 53 |
| Regulatory liabilities | **597** | 392 |
| Pensions and other benefit plans | **168** | 82 |
| Deferred revenue | **42** | 58 |
| Asset retirement obligations | **33** | 36 |
| Other | **72** | 27 |
| | **1,196** | 783 |

## NOTE 12 REGULATED BUSINESS

Regulatory assets and liabilities represent future revenues which are expected to be recovered from or refunded to customers in future periods through the rate-setting process associated with certain costs, incurred in the current period or in prior periods, and under or over collection of revenues.

### Canadian Regulated Operations

Canadian natural gas transmission services are provided under gas transportation tariffs that provide for cost recovery including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's wholly-owned and partially-owned Canadian pipelines are typically set through a process that involves filing an application for a change in rates with the regulator. Under the regulation, rates are underpinned by the total annual revenue requirement which includes a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated pipelines have generally been regulated using a cost-of-service model, where the forecast costs plus a return on capital equals the revenues for the upcoming year. To the extent that actual costs are more or less than the forecast costs, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in revenues at that time. Those costs, for which the regulator does not allow the difference between actual and forecast costs to be deferred, are included in the determination of net income in the year in which they are incurred.

The Canadian Mainline, the BC System, the Foothills System and the TransQuébec & Maritimes System (TQM) are regulated by the NEB under the National Energy Board Act. The Alberta System is regulated by the EUB primarily under the provisions of the Gas Utilities Act (Alberta) and the Pipeline Act (Alberta). The NEB and the EUB regulate the construction, operations, tolls and the determination of revenues of the Canadian natural gas transmission operations.

*Canadian Mainline*
In February 2005, TransCanada and its Canadian Mainline shippers entered into a negotiated settlement that addresses all elements of the Canadian Mainline's 2005 tolls (2005 Settlement). The 2005 Settlement was approved by the NEB in April 2005. Pursuant to the 2005 Settlement, the cost of capital of the Canadian Mainline's 2005 revenue requirement and resulting tolls were determined based on the RH-2-2004 Phase II proceeding relating to the 2004 cost of capital of the Canadian Mainline. The RH-2-2004 Phase II decision increased the deemed capital structure for the Canadian Mainline to 36 per cent from 33 per cent, effective January 1, 2004. The impact of this has been recognized in 2005. The return on equity of the Canadian Mainline continues to be based on the NEB's approved rate of return on common equity (ROE) formula which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding.

Under the 2005 Settlement, the Canadian Mainline's operations, maintenance and administrative (OM&A) costs for 2005 were fixed and variances between the 2005 negotiated and actual level of OM&A costs accrued to TransCanada. All other cost and revenue component variances were treated on a full recovery basis. The allowed ROE in 2005 was 9.46 per cent.

*Alberta System*
The Alberta System operates under the 2005-2007 Revenue Requirement Settlement. This settlement, approved by the EUB in June 2005, encompassed all elements of the Alberta System's revenue requirement for 2005, 2006 and 2007 and established methodologies for calculation of the revenue requirement for all three years, based on the recovery of all cost components and the use of deferral accounts.

Fixed costs are operating costs and certain other costs, including foreign exchange on interest payments, uninsured losses and amortization of severance costs. These costs were set for each year for 2005, 2006 and 2007 and any difference between actual and forecast fixed costs will be included in the determination of net income in the year in which they are incurred. Costs other than fixed costs are forecast at the beginning of each year and included in the calculation of the revenue requirement. Any variance between the forecast and actual costs incurred will be included in a deferral account and adjusted in the following year's revenue requirement. The settlement also set the ROE using the formula for determining the annual generic rate of return on common equity established in the EUB's General Cost of Capital Decision 2004-052 on a deemed common equity of 35 per cent for all three years. The allowed ROE in 2005 was 9.50 per cent.

*Other Canadian Pipelines*
Similar to the Canadian Mainline, the NEB approves pipeline tolls on an annual cost of service basis for the BC System, Foothills System and TQM. The NEB allows each pipeline to charge a schedule of tolls based on the estimated cost of service. This schedule of tolls is used for a current year until a new toll filing is made for the following year. Differences between the estimated cost of service and the actual cost of service are included in the following year's tolls. The ROE for these Canadian pipelines is based on the NEB's approved ROE formula which was established in the RH-2-94 Multi-Pipeline Cost of Capital proceeding, being 9.46 per cent in 2005. The deemed equity component of each of the pipelines' capital structure was set at 30 per cent for 2005.

### U.S. Regulated Operations
TransCanada's wholly-owned and partially-owned U.S. pipelines, including Great Lakes, Iroquois, Portland, Northern Border and Tuscarora Gas Transmission System, are 'natural gas companies' operating under the provisions of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and are subject to the jurisdiction of the FERC. The Natural Gas Act of 1938 grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

*Gas Transmission Northwest System and North Baja System*
Rates and tariffs of the Gas Transmission Northwest System and the North Baja System have been approved by the FERC. These two systems operate under fixed rate models, whereby maximum and minimum rates for various service types have been ordered by FERC and under which each of the two systems are permitted to discount or negotiate rates on a non-discriminatory basis. General rates for mainline capacity on the Gas Transmission Northwest System were last reviewed by the FERC in a 1994 rate proceeding. A settlement of the 1994 rate proceeding, which set rate levels that remain in effect today, was approved by the FERC in 1996. Rates for capacity on the North Baja System were established in the FERC's initial order certificating construction and operations of its system.

*Portland*
In 2003, Portland received final approval from FERC of its general rate case under the Natural Gas Act of 1938. Portland is required to file a general rate case under the Natural Gas Act of 1938 with a proposed effective date of April 1, 2008.

### Regulatory Assets and Liabilities

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | Remaining Recovery/ Settlement Period |
|---|---|---|---|
| | | | (years) |
| **Regulatory Assets** | | | |
| Unrealized losses on derivatives – Canadian Mainline[1] | **43** | 35 | 2 - 5 |
| Unrealized losses on derivatives – BC System[1] | **33** | 25 | 8 |
| Foreign exchange – Alberta System[2] | **32** | 33 | 24 |
| Contractor claim – Trans Québec & Maritimes[3] | **–** | 16 | n/a |
| Phase II Preliminary Expenditures – Foothills System[4] | **23** | 25 | 10 |
| Deferred charge on reacquired debt – Gas Transmission Northwest System[5] | **14** | 6 | 4 - 20 |
| Transitional other benefit obligations – Canadian Mainline[6] | **10** | 11 | 11 |
| Other | **28** | 23 | 3 - 11 |
| **Total Regulatory Assets (Other Assets)** | **183** | 174 | |
| **Regulatory Liabilities** | | | |
| Operating and debt service regulatory liabilities[7] | **273** | 146 | 1 |
| Foreign exchange on long-term debt – Canadian Mainline[2] | **202** | 153 | 2 - 42 |
| Foreign exchange on long-term debt – Alberta System[2] | **59** | 36 | 7 - 24 |
| Foreign exchange on long-term debt – BC System[2] | **20** | 16 | 8 |
| Post-retirement benefits other than pension – Gas Transmission Northwest System[8] | **17** | 15 | n/a |
| Other | **26** | 26 | n/a |
| **Total Regulatory Liabilities (Deferred Amounts)** | **597** | 392 | |

(1) Unrealized losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest rate swaps which act as economic hedges. The cross-currency swaps relate to Canadian Mainline and BC System foreign debt instruments. The Canadian Mainline interest rate swaps were entered into as a result of the Interest Rate Management Program approved by the NEB as a component of the 1996 - 1999 Incentive Cost Recovery and Revenue Settlement. Interest savings or losses are determined when the interest swaps are settled. In the absence of rate regulation accounting, Canadian GAAP would require the inclusion of these fair value losses in the operating results as they were not documented as hedges for accounting purposes. In the absence of rate regulation accounting, pre-tax operating results for 2005 would have been $8 million lower for each of the Canadian Mainline and the BC System.

(2) The foreign exchange reserve account in the Alberta System, as approved by the EUB, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Each year, the estimated gain/(loss) on foreign currency debt is amortized over the remaining years of the longest outstanding U.S. debt issue. The annual amortization amount is included in the determination of tolls for the year. The foreign exchange on long-term debt on the Canadian Mainline, Alberta System and BC System represent the variance resulting from re-valuing foreign currency denominated debt instruments from their historic foreign exchange rate to the current foreign exchange rate. Foreign exchange gains/(losses) realized when foreign debt matures or is redeemed early are expected to be recovered through the determination of future tolls. In the absence of rate regulation accounting, GAAP would have required the inclusion of these unrealized gains or losses either on the balance sheet or income statement depending on whether the foreign debt is designated as a hedge of the Company's net investment in foreign assets.

(3) As at December 31, 2004, Trans Québec & Maritimes had deferred $32 million related to a contractor claim regarding cost overruns on an extension project to Portland. TransCanada's share of this deferral was $16 million. In 2005, the NEB approved Trans Québec & Maritimes 2005 tolls application as filed which allowed for this amount to be capitalized in 2005. This amount would have been capitalized under GAAP.

(4) Phase II Preliminary Expenditures are costs incurred by Foothills System prior to 1981 related to development of Canadian facilities to deliver Alaskan natural gas that have been approved by the regulator for collection through straight-line amortization over the period November 1, 2002 to December 31, 2015. In the absence of rate regulation accounting, GAAP would have required these costs to be expensed in the year incurred, increasing pre-tax operating results in 2005 by $2 million.

(5) Deferred charge on reacquired debt includes the unamortized debt issuance costs and premiums or discounts on Gas Transmission Northwest System debt that was reacquired prior to its original maturity date, along with any costs incurred or gains realized on reacquiring this debt. These amounts continue to be amortized over the original life of the debt that has been reacquired. In the absence of rate regulation accounting, GAAP would require the inclusion of these costs in the operating results to the extent that the debt has

not been renegotiated. Consequently, pre-tax operating results in 2005 are $8 million higher than would have been reported in the absence of rate regulation accounting.

(6) The regulatory asset with respect to the transitional other benefit obligations is being amortized over 17 years, starting January 1, 2000. Amortization will be completed by December 31, 2016, at which time the full transitional obligation will have been recovered through tolls. In the absence of rate regulation accounting, pre-tax operating results would have been $1 million higher.

(7) Operating and debt service regulatory liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determination of the tolls for the immediately following calendar year. In the absence of rate regulation accounting, GAAP may require the inclusion of these variances in the operating results of the year in which the variances were incurred. Pre-tax operating results for 2005 are the same as would have been the case in the absence of rate regulation accounting.

(8) In Gas Transmission Northwest System's rates, an amount is recovered for post-retirement benefits other than pension (PBOP). This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense determined under GAAP. In the absence of rate regulation accounting, GAAP would require the inclusion of this amount in operating results and pre-tax operating results in 2005 would have been $2 million higher than reported.

As prescribed by the regulators, the taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations. As permitted by GAAP, this method is also used for accounting purposes, since there is reasonable expectation that future income taxes payable will be included in future costs of service and recorded in revenues at that time. Consequently, future income tax liabilities have not been recognized as it is expected that when these amounts become payable, they will be recovered through future rate revenues. In the absence of rate regulation accounting, GAAP would require the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities in the amount of $1,619 million at December 31, 2005 (2004 – $1,692 million) would have been recorded. For the U.S. natural gas transmission operations, the liability method of accounting is used for both accounting and tollmaking purposes, whereby future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of such assets and liabilities. As this method is also used for tollmaking purposes for the U.S. natural gas transmission operations, the current year's revenues include a tax provision which is calculated based on the liability method of accounting and therefore, there is no recognition of a related regulatory asset or liability.

## NOTE 13 PREFERRED SECURITIES

The US$460 million (2005 – $536 million; 2004 – $554 million) 8.25 per cent preferred securities of TCPL are redeemable by the issuer at par at any time. The issuer may elect to defer interest payments on the Preferred Securities and settle the deferred interest in either cash or common shares.

## NOTE 14 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the consolidated balance sheet are as follows.

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Preferred shares of subsidiary | **389** | 389 |
| Non-controlling interest in PipeLines LP | **318** | 235 |
| Other | **76** | 76 |
| | **783** | 700 |

The Company's non-controlling interests included in the consolidated income statement are as follows.

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Preferred share dividends of subsidiary | **22** | 22 | 22 |
| Non-controlling interest in PipeLines LP | **52** | 46 | 43 |
| Other | **10** | 10 | 2 |
| | **84** | 78 | 67 |

### Preferred Shares of Subsidiary

| *December 31* | Number of Shares | Dividend Rate Per Share | Redemption Price Per Share | **2005** | 2004 |
|---|---|---|---|---|---|
| | (thousands) | | | (millions of dollars) | (millions of dollars) |
| **Cumulative First Preferred Shares of Subsidiary** | | | | | |
| Series U | 4,000 | $2.80 | $50.00 | **195** | 195 |
| Series Y | 4,000 | $2.80 | $50.00 | **194** | 194 |
| | | | | **389** | 389 |

The authorized number of preferred shares of TCPL issuable in series is unlimited. All of the cumulative first preferred shares of subsidiary are without par value.

On or after October 15, 2013, for the Series U shares, and on or after March 5, 2014, for the Series Y shares, the issuer may redeem the shares at $50 per share.

At December 31, 2005, the non-controlling interest in PipeLines LP is 86.6 per cent. Other non-controlling interests at December 31, 2005 include the 38.3 per cent non-controlling interest in Portland. Revenues received from PipeLines LP and Portland with respect to services provided by TransCanada for the year ended December 31, 2005 were $1 million (2004 – $1 million; 2003 –$1 million) and $6 million (2004 – $4 million; 2003 – nil), respectively.

## NOTE 15 COMMON SHARES

| | Number of Shares | Amount |
|---|---|---|
| | (thousands) | (millions of dollars) |
| Outstanding at January 1, 2003 | 479,502 | 4,614 |
| Exercise of options | 3,698 | 65 |
| Outstanding at December 31, 2003 | 483,200 | 4,679 |
| Exercise of options | 1,714 | 32 |
| Outstanding at December 31, 2004 | 484,914 | 4,711 |
| Exercise of options | **2,322** | **44** |
| **Outstanding at December 31, 2005** | **487,236** | **4,755** |

### Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares of no par value.

### Net Income Per Share

Basic and diluted earnings per share are calculated based on the weighted average number of common shares outstanding during the year of 486.2 million and 489.1 million (2004 – 484.1 million and 486.7 million; 2003 – 481.5 million and 483.9 million), respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

### Stock Options

| | Number of Options | Weighted Average Exercise Prices | Options Exercisable |
|---|---|---|---|
| | (thousands) | | (thousands) |
| Outstanding at January 1, 2003 | 12,892 | $18.92 | 10,258 |
| Granted | 1,503 | $22.42 | |
| Exercised | (3,698) | $17.59 | |
| Cancelled or expired | (342) | $24.07 | |
| Outstanding at December 31, 2003 | 10,355 | $19.73 | 7,588 |
| Granted | 1,331 | $26.85 | |
| Exercised | (1,714) | $18.42 | |
| Cancelled or expired | (7) | $24.25 | |
| Outstanding at December 31, 2004 | 9,965 | $20.90 | 7,239 |
| Granted | **1,075** | **$30.21** | |
| Exercised | **(2,322)** | **$18.57** | |
| Cancelled or expired | **(4)** | **$25.34** | |
| **Outstanding at December 31, 2005** | **8,714** | **$22.67** | **6,300** |

The following table summarizes information for stock options outstanding at December 31, 2005.

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number of Options | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price | Number of Options | Weighted Average Exercise Price |
| | (thousands) | (years) | | (thousands) | |
| $10.03 to $18.01 | 1,347 | 4.9 | $15.64 | 1,347 | $15.64 |
| $18.81 to $20.59 | 1,303 | 3.2 | $19.97 | 1,303 | $19.97 |
| $21.00 to $21.86 | 1,415 | 6.0 | $21.40 | 1,415 | $21.40 |
| $22.33 to $24.49 | 1,787 | 3.9 | $22.82 | 1,321 | $22.99 |
| $24.61 to $26.85 | 1,787 | 4.8 | $26.26 | 905 | $25.70 |
| $30.09 to $36.67 | 1,075 | 6.2 | $30.21 | 9 | $30.09 |
| | 8,714 | 4.8 | $22.67 | 6,300 | $20.83 |

At December 31, 2005, an additional four million common shares have been reserved for future issuance under TransCanada's Stock Option Plan. In 2005, TransCanada issued 1,075,000 options to purchase common shares at an average price of $30.21 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be $2.37. The Company used the Black-Scholes model for these calculations with the weighted average assumptions being four years of expected life, 4.0 per cent interest rate, 15 per cent volatility and 3.3 per cent dividend yield. The amount expensed for stock options, with a corresponding increase in contributed surplus for the year ended December 31, 2005, was $3 million (2004 – $3 million; 2003 – $2 million).

### Shareholder Rights Plan

The Company's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right which entitles certain holders to purchase common shares of the Company at 50 per cent of the then market price.

## NOTE 16 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company issues short-term and long-term debt, purchases and sells energy commodities, including amounts in foreign currencies, and invests in foreign operations. These activities result in exposures to changing interest rates, energy commodity prices and foreign currency exchange rates. The Company uses derivatives to manage the risk that results from these activities.

The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates. The fair value of power, natural gas and heat rate derivatives has been calculated using estimated forward prices for the relevant period.

### Net Investment in Foreign Operations

At December 31, 2005 and 2004, the Company had net investments in self sustaining foreign operations with a U.S. dollar functional currency which created an exposure to changes in exchange rates. The Company uses U.S. dollar denominated debt and derivatives to hedge this exposure on an after-tax basis. The fair value for derivatives used to manage the exposure is shown in the table below.

| **Asset/(Liability)**<br>*December 31 (millions of dollars)* | Accounting Treatment | **2005**<br>**Fair Value** | **2005**<br>**Notional or Notional Principal Amount** | 2004<br>Fair Value | 2004<br>Notional or Notional Principal Amount |
|---|---|---|---|---|---|
| U.S. dollar cross-currency swaps (maturing 2006 to 2012) | Hedge | **119** | **U.S. 450** | 95 | U.S. 400 |
| U.S. dollar forward foreign exchange contracts (maturing 2006) | Hedge | **5** | **U.S. 525** | (1) | U.S. 305 |
| U.S. dollar options (maturing 2006) | Hedge | **–** | **U.S. 60** | 1 | U.S. 100 |

### Reconciliation of Foreign Exchange Adjustment (Losses)/Gains

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Balance at January 1 | **(71)** | (40) |
| Translation losses on foreign currency denominated net assets(1) | **(21)** | (39) |
| Gains on derivatives | **23** | 52 |
| Income taxes | **(21)** | (44) |
| Balance at December 31 | **(90)** | (71) |

(1) In 2005, includes gains of $80 million (2004 – $101 million) related to foreign currency denominated debt designated as a hedge.

### Foreign Exchange Gains/(Losses)

Foreign exchange gains included in Other Expenses/(Income) for the year ended December 31, 2005 are $19 million (2004 – $6 million; 2003 – nil).

### Foreign Exchange and Interest Rate Management Activity

The Company manages the foreign exchange and interest rate risks related to its U.S. dollar denominated debt, and transactions and interest rate exposures of the Canadian Mainline, the Alberta System and the BC System through the use of foreign currency and interest rate derivatives. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. The details of the foreign exchange and interest rate derivatives are shown in the table below.

| Asset/(Liability)<br>*December 31 (millions of dollars)* | Accounting Treatment | **2005**<br>**Fair Value** | **2005**<br>**Notional or Notional Principal Amount** | 2004<br>Fair Value | 2004<br>Notional or Notional Principal Amount |
|---|---|---|---|---|---|
| **Foreign Exchange** | | | | | |
| Cross-currency swaps | | | | | |
| (maturing 2010 to 2013) | Non-hedge | **(86)** | **363/U.S. 257** | (69) | 363/U.S. 257 |
| **Interest Rate** | | | | | |
| Interest rate swaps | | | | | |
| Canadian dollars | | | | | |
| (maturing 2007 to 2008) | Hedge | **4** | **100** | 7 | 145 |
| (maturing 2006 to 2009) | Non-hedge | **7** | **374** | 9 | 374 |
| | | **11** | | 16 | |
| U.S. dollars | | | | | |
| (maturing 2007 to 2009) | Non-hedge | **5** | **U.S. 100** | 7 | U.S. 100 |

The Company manages the foreign exchange and interest rate exposures of its other businesses through the use of foreign currency and interest rate derivatives. The details of these foreign currency and interest rate derivatives are shown in the table below.

| Asset/(Liability)<br>*December 31 (millions of dollars)* | Accounting Treatment | **2005**<br>**Fair Value** | **2005**<br>**Notional or Notional Principal Amount** | 2004<br>Fair Value | 2004<br>Notional or Notional Principal Amount |
|---|---|---|---|---|---|
| **Foreign Exchange** | | | | | |
| Options (maturing 2006) | Non-hedge | **1** | **U.S. 195** | 2 | U.S. 255 |
| Forward foreign exchange contracts | | | | | |
| (maturing 2006) | Hedge | **2** | **U.S. 29** | – | – |
| (maturing 2006) | Non-hedge | **1** | **U.S. 208** | 1 | U.S. 129 |
| **Interest Rate** | | | | | |
| Options | Non-hedge | **–** | **–** | – | U.S. 50 |
| Interest rate swaps | | | | | |
| Canadian dollar | | | | | |
| (maturing 2007 to 2009) | Hedge | **1** | **100** | 4 | 100 |
| (maturing 2006 to 2011) | Non-hedge | **1** | **423** | 5 | 485 |
| | | **2** | | 9 | |
| U.S. dollar | | | | | |
| (maturing 2013) | Hedge | **–** | **U.S. 50** | 3 | U.S. 375 |
| (maturing 2006 to 2010) | Non-hedge | **18** | **U.S. 550** | 22 | U.S. 500 |
| | | **18** | | 25 | |

Certain of the Company's joint ventures use interest rate derivatives to manage interest rate exposures. The Company's proportionate share of the fair value of these outstanding derivatives at December 31, 2005 was nil (2004 – $1 million).

**Energy Price Risk Management**

The Company executes power, natural gas and heat rate derivatives for overall management of its asset portfolio. Heat rate contracts are contracts for the sale or purchase of power that are priced based on a natural gas index. The fair value and notional volumes of contracts for differences and the swap, future, option and heat rate contracts are shown in the tables below.

**Power**

| **Asset/(Liability)**<br>*December 31 (millions of dollars)* | Accounting Treatment | **2005**<br>**Fair Value** | 2004<br>Fair Value |
|---|---|---|---|
| Power – swaps and contracts for differences | | | |
| (maturing 2006 to 2011) | Hedge | **(130)** | 7 |
| (maturing 2006 to 2010) | Non-hedge | **13** | (2) |
| Gas – swaps, futures and options | | | |
| (maturing 2006 to 2016) | Hedge | **17** | (39) |
| (maturing 2006 to 2008) | Non-hedge | **(11)** | (2) |
| Heat rate contracts | | | |
| (maturing 2006) | Non-hedge | **–** | (1) |

| **Notional Volumes** | **Accounting** | **Power (GWh)[1]** | | **Gas (Bcf)[1]** | |
|---|---|---|---|---|---|
| *December 31, 2005* | **Treatment** | **Purchases** | **Sales** | **Purchases** | **Sales** |
| Power – swaps and contracts for differences | | | | | |
| (maturing 2006 to 2011) | **Hedge** | **2,566** | **7,780** | **–** | **–** |
| (maturing 2006 to 2010) | **Non-hedge** | **1,332** | **456** | **–** | **–** |
| Gas – swaps, futures and options | | | | | |
| (maturing 2006 to 2016) | **Hedge** | **–** | **–** | **91** | **69** |
| (maturing 2006 to 2008) | **Non-hedge** | **–** | **–** | **15** | **18** |
| Heat rate contracts | | | | | |
| (maturing 2006) | **Non-hedge** | **–** | **35** | **–** | **–** |
| *December 31, 2004* | | | | | |
| Power – swaps and contracts for differences | Hedge | 3,314 | 7,029 | – | – |
| | Non-hedge | 438 | – | – | – |
| Gas – swaps, futures and options | Hedge | – | – | 80 | 84 |
| | Non-hedge | – | – | 5 | 8 |
| Heat rate contracts | Non-hedge | – | 229 | 2 | – |

(1) Gigawatt hours (GWh); billion cubic feet (Bcf).

Certain of the Company's joint ventures use power derivatives to manage energy price risk exposures. The Company's proportionate share of the fair value of these outstanding power sales derivatives at December 31, 2005 was $(38) million (2004 – nil) and relates to contracts which cover the period 2006 to 2008. The Company's proportionate share of the notional sales volumes associated with this exposure at December 31, 2005 was 2,058 GWh (2004 – nil).

### Fair Value of Financial Instruments

The fair value of cash and short-term investments and notes payable approximates their carrying amounts due to the short period to maturity. The fair value of long-term debt, long-term debt of joint ventures and preferred securities is determined using market prices for the same or similar issues.

| | 2005 | | 2004 | |
|---|---|---|---|---|
| *December 31 (millions of dollars)* | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |
| **Long-Term Debt** | | | | |
| Canadian Mainline | **4,233** | **5,327** | 4,445 | 5,473 |
| Alberta System | **2,258** | **2,858** | 2,105 | 2,668 |
| GTN | **466** | **470** | 632 | 627 |
| Foothills System | **400** | **415** | 400 | 413 |
| Portland | **281** | **292** | 308 | 328 |
| Other | **2,395** | **2,486** | 2,633 | 2,731 |
| **Long-Term Debt of Joint Ventures** | **978** | **1,101** | 893 | 1,003 |
| **Preferred Securities** | **536** | **554** | 554 | 572 |

The fair value is provided solely for information purposes and is not recorded in the consolidated balance sheet.

### Credit Risk

Credit risk results from the possibility that a counterparty to a derivative in which the Company has an unrealized gain fails to perform according to the terms of the contract. Credit exposure is minimized through the use of established credit management techniques, including formal assessment processes, contractual and collateral requirements, master netting arrangements and credit exposure limits. At December 31, 2005, for foreign currency and interest rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $127 million and $44 million, respectively. At December 31, 2005, for power, natural gas and heat rate derivatives, total credit risk and the largest credit exposure to a single counterparty were $63 million and $39 million, respectively.

## NOTE 17 INCOME TAXES

### Provision for Income Taxes

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **Current** | | | |
| Canada | **499** | 373 | 243 |
| Foreign | **51** | 41 | 41 |
| | **550** | 414 | 284 |
| **Future** | | | |
| Canada | **(46)** | 34 | 183 |
| Foreign | **106** | 43 | 47 |
| | **60** | 77 | 230 |
| | **610** | 491 | 514 |

### Geographic Components of Income

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Canada | **1,316** | 1,207 | 1,058 |
| Foreign | **587** | 342 | 324 |
| Income from continuing operations before income taxes and non-controlling interests | **1,903** | 1,549 | 1,382 |

### Reconciliation of Income Tax Expense

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Income from continuing operations before income taxes and non-controlling interests | **1,903** | 1,549 | 1,382 |
| Federal and provincial statutory tax rate | **33.6%** | 33.9% | 36.7% |
| Expected income tax expense | **639** | 525 | 507 |
| Income tax differential related to regulated operations | **71** | 62 | 29 |
| Higher/(lower) effective foreign tax rates | **2** | 2 | (2) |
| Large corporations tax | **15** | 21 | 28 |
| Lower effective tax rate on equity in earnings of affiliates | **(29)** | (25) | (27) |
| Non-taxable portion of gains on sale of assets | **(68)** | (66) | – |
| Change in valuation allowance | **–** | (7) | (3) |
| Other | **(20)** | (21) | (18) |
| Actual income tax expense | **610** | 491 | 514 |

### Future Income Tax Assets and Liabilities

| *December 31 (millions of dollars)* | **2005** | 2004 |
|---|---|---|
| Deferred costs | **119** | 71 |
| Deferred revenue | **11** | 18 |
| Alternative minimum tax credits | **–** | 10 |
| Net operating and capital loss carryforwards | **1** | 7 |
| Other | **43** | 72 |
| | **174** | 178 |
| Less: Valuation allowance | **14** | 17 |
| Future income tax assets, net of valuation allowance | **160** | 161 |
| Difference in accounting and tax bases of plant, equipment and PPAs | **637** | 456 |
| Investments in subsidiaries and partnerships | **131** | 114 |
| Unrealized foreign exchange gains on long-term debt | **68** | 45 |
| Other | **27** | 55 |
| Future income tax liabilities | **863** | 670 |
| Net future income tax liabilities | **703** | 509 |

### Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments which the Company does not intend to repatriate in the foreseeable future. If provision for these taxes had been made, future income tax liabilities would increase by approximately $61 million at December 31, 2005 (2004 – $57 million).

### Income Tax Payments

Income tax payments of $531 million were made during the year ended December 31, 2005 (2004 – $419 million; 2003 – $220 million).

## NOTE 18 NOTES PAYABLE

| | **2005** | | 2004 | |
|---|---|---|---|---|
| | **Outstanding December 31[1]** | **Weighted Average Interest Rate Per Annum at December 31** | Outstanding December 31[1] | Weighted Average Interest Rate Per Annum at December 31 |
| Canadian dollars | **765** | **3.4%** | 546 | 2.6% |
| U.S. dollars (2005 – US$169) | **197** | **4.5%** | – | – |
| | **962** | | 546 | |

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

Notes payable consists of commercial paper and line of credit drawings. At December 31, 2005, total credit facilities of $2.0 billion were available to support the Company's commercial paper programs and for general corporate purposes. Of this total, $1.5 billion was a committed five-year term syndicated credit facility. This facility is extendible on an annual basis and is revolving. In December 2005, the facility was extended to December 2010. The remaining amounts are either demand or non-extendible facilities.

At December 31, 2005, the Company had used approximately $271 million of its total lines of credit for letters of credit and to support its ongoing commercial arrangements. If drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks and at other negotiated financial bases. The cost to maintain the unused portion of the lines of credit was $2 million for the year ended December 31, 2005 (2004 – $2 million).

## NOTE 19 ASSET RETIREMENT OBLIGATIONS

At December 31, 2005, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to Gas Transmission were $46 million (2004 – $48 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $12 million (2004 – $12 million) after discounting the estimated cash flows at rates ranging from 5.5 per cent to 6.6 per cent. At December 31, 2005, the expected timing of payment for settlement of the obligations ranges from 12 to 24 years. No amount has been recorded for asset retirement obligations relating to the regulated natural gas transmission operation assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

At December 31, 2005, the estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Power business were $95 million (2004 – $128 million), calculated using an inflation rate ranging from two to three per cent per annum. The estimated fair value of this liability was $21 million (2004 – $24 million) after discounting the estimated cash flows at rates ranging from 5.5 per cent to 6.6 per cent. At December 31, 2005, the expected timing of payment for settlement of the obligations ranges from 13 to 28 years.

For the hydroelectric power plant assets, as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements, no amount has been recorded for asset retirement obligations. For the Bruce Power nuclear assets, as the lessor is responsible for decommissioning liabilities under the lease agreement, no amount has been recorded for asset retirement obligations.

### Reconciliation of Asset Retirement Obligations

| *(millions of dollars)* | Gas Transmission | Power | Total |
|---|---|---|---|
| Balance at January 1, 2003 | 2 | 6 | 8 |
| Revisions in estimated cash flows | – | 1 | 1 |
| Balance at December 31, 2003 | 2 | 7 | 9 |
| New obligations and revisions in estimated cash flows | 9 | 21 | 30 |
| Removal of Power LP redemption obligations | – | (5) | (5) |
| Accretion expense | 1 | 1 | 2 |
| Balance at December 31, 2004 | 12 | 24 | 36 |
| Revisions in estimated cash flows and lives | **(1)** | **1** | **–** |
| Sale of Power LP | **–** | **(5)** | **(5)** |
| Accretion expense | **1** | **1** | **2** |
| **Balance at December 31, 2005** | **12** | **21** | **33** |

## NOTE 20 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment, and increase annually by a portion of the increase in the Consumer Products Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately 11 years.

The Company also provides its employees with post-employment benefits other than pensions, including termination benefits and defined life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which at December 31, 2005 was approximately 12 years.

In 2005, the Company expensed $2 million (2004 – $1 million; 2003 – $1 million) related to retirement savings plans for its U.S. employees.

Total cash payments for employee future benefits for 2005, consisting of cash contributed by the Company to the DB Plans and other benefit plans was $74 million (2004 – $89 million).

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2006, and the next required valuation is as of January 1, 2007.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| *(millions of dollars)* | **2005** | 2004 | **2005** | 2004 |
| **Change in Benefit Obligation** | | | | |
| Benefit obligation – beginning of year | **1,100** | 960 | **123** | 106 |
| Current service cost | **32** | 28 | **3** | 3 |
| Interest cost | **63** | 58 | **7** | 7 |
| Employee contributions | **3** | 2 | **–** | – |
| Benefits paid | **(60)** | (66) | **(6)** | (4) |
| Actuarial loss/(gain) | **149** | 46 | **21** | (12) |
| Foreign exchange rate changes | **(3)** | – | **–** | – |
| Curtailment | **(2)** | – | **–** | – |
| Acquisition | **–** | 72 | **–** | 23 |
| Benefit obligation – end of year | **1,282** | 1,100 | **148** | 123 |
| **Change in Plan Assets** | | | | |
| Plan assets at fair value – beginning of year | **970** | 799 | **26** | – |
| Actual return on plan assets | **119** | 97 | **2** | 1 |
| Employer contributions | **67** | 84 | **5** | 4 |
| Employee contributions | **3** | 2 | **–** | – |
| Benefits paid | **(60)** | (66) | **(6)** | (4) |
| Foreign exchange rate changes | **(3)** | – | **–** | – |
| Acquisition | **–** | 54 | **–** | 25 |
| Plan assets at fair value – end of year | **1,096** | 970 | **27** | 26 |
| Funded status – plan deficit | **(186)** | (130) | **(121)** | (97) |
| Unamortized net actuarial loss | **331** | 255 | **45** | 25 |
| Unamortized past service costs | **36** | 39 | **8** | 7 |
| Accrued benefit asset/(liability), net of valuation allowance | **181** | 164 | **(68)** | (65) |

The accrued benefit (asset)/liability, net of valuation allowance of nil, is included in the Company's balance sheet as follows.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Other assets | **268** | 224 | **4** | 3 |
| Accounts payable | **(70)** | (42) | **(7)** | (5) |
| Deferred amounts | **(17)** | (18) | **(65)** | (63) |
| Total | **181** | 164 | **(68)** | (65) |

Included in the above accrued benefit obligation and fair value of plan assets at year end are the following amounts in respect of plans that are not fully funded.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Accrued benefit obligation | **(1,263)** | (1,084) | **(124)** | (100) |
| Fair value of plan assets | **1,075** | 952 | **–** | – |
| Funded status – plan deficit | **(188)** | (132) | **(124)** | (100) |

The Company's expected contributions for the year ended December 31, 2006 are approximately $95 million for the pension benefit plans and approximately $7 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service.

| *(millions of dollars)* | Pension Benefits | Other Benefits |
|---|---|---|
| 2006 | 58 | 6 |
| 2007 | 59 | 7 |
| 2008 | 62 | 7 |
| 2009 | 64 | 8 |
| 2010 | 67 | 8 |
| Years 2011 to 2015 | 378 | 44 |

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations at December 31 are as follows.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Discount rate | **5.00%** | 5.75% | **5.15%** | 6.00% |
| Rate of compensation increase | **3.50%** | 3.50% | | |

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost for years ended December 31 are as follows.

| | Pension Benefit Plans | | | Other Benefit Plans | | |
|---|---|---|---|---|---|---|
| | **2005** | 2004 | 2003 | **2005** | 2004 | 2003 |
| Discount rate | **5.75%** | 6.00% | 6.25% | **6.00%** | 6.25% | 6.50% |
| Expected long-term rate of return on plan assets | **6.90%** | 6.90% | 7.25% | **7.20%** | | |
| Rate of compensation increase | **3.50%** | 3.50% | 3.75% | | | |

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for both the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and future expectations of the level and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in the determination of the overall expected rate of return. The discount rate is based on market interest rates of high quality bonds that match the timing and benefits expected to be paid under each plan.

For measurement purposes, a 9.0 per cent annual rate of increase in the per capita cost of covered health care benefits was assumed for 2006. The rate was assumed to decrease gradually to 5.0 per cent for 2015 and remain at that level thereafter. A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

| *(millions of dollars)* | Increase | Decrease |
|---|---|---|
| Effect on total of service and interest cost components | 2 | (1) |
| Effect on post-employment benefit obligation | 18 | (16) |

The Company's net benefit cost is as follows.

| *Year ended December 31 (millions of dollars)* | Pension Benefit Plans | | | Other Benefit Plans | | |
|---|---|---|---|---|---|---|
| | **2005** | 2004 | 2003 | **2005** | 2004 | 2003 |
| Current service cost | **32** | 28 | 25 | **3** | 3 | 2 |
| Interest cost | **63** | 58 | 52 | **7** | 7 | 6 |
| Actual return on plan assets | **(119)** | (97) | (89) | **(2)** | (1) | – |
| Actuarial loss/(gain) | **149** | 46 | 66 | **21** | (12) | 7 |
| Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost | **125** | 35 | 54 | **29** | (3) | 15 |
| Difference between expected and actual return on plan assets | **54** | 39 | 38 | **–** | 1 | – |
| Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation | **(131)** | (32) | (58) | **(20)** | 13 | (6) |
| Difference between amortization of past service costs and actual plan amendments | **3** | 3 | 3 | **1** | – | 1 |
| Amortization of transitional obligation related to regulated business | **–** | – | – | **2** | 2 | 2 |
| Net benefit cost recognized | **51** | 45 | 37 | **12** | 13 | 12 |

The Company's pension plans' weighted average asset allocations at December 31, by asset category, and weighted average target allocation at December 31, by asset category, is as follows.

| | Percentage of Plan Assets | | **Target Allocation** |
|---|---|---|---|
| **Asset Category** | **2005** | 2004 | **2005** |
| Debt securities | **43%** | 44% | **35% to 60%** |
| Equity securities | **57%** | 56% | **40% to 65%** |
| | **100%** | 100% | |

Debt securities include the Company's long-term debt in the amount of $3 million (0.3 per cent of total plan assets) at December 31, 2005 and 2004. Equity securities include the Company's common shares in the amounts of $5 million (0.5 per cent of total plan assets) and $3 million (0.3 per cent of total plan assets) at December 31, 2005 and 2004, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

**Employee Future Benefits of Joint Ventures**

Certain of the Company's joint ventures sponsor DB Plans, as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The amounts that follow represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits for 2005, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $4 million (2004 – $1 million).

The Company's joint ventures measure the accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of January 1, 2006, and the next required valuation will be as of January 1, 2007.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| *(millions of dollars)* | **2005** | 2004 | **2005** | 2004 |
| **Change in Benefit Obligation** | | | | |
| Benefit obligation – beginning of year | **45** | 47 | **2** | 2 |
| Current service cost | **4** | 1 | **1** | – |
| Interest cost | **7** | 3 | **1** | – |
| Employee contributions | **–** | – | **–** | – |
| Benefits paid | **(3)** | (3) | **–** | – |
| Actuarial loss | **17** | – | **2** | – |
| Foreign exchange rate changes | **(1)** | (3) | | – |
| Bruce B[(1)] | **610** | | **75** | |
| Benefit obligation – end of year | **679** | 45 | **81** | 2 |
| **Change in Plan Assets** | | | | |
| Plan assets at fair value – beginning of year | **57** | 56 | **–** | – |
| Actual return on plan assets | **18** | 7 | **–** | – |
| Employer contributions | **4** | 1 | **–** | – |
| Employee contributions | **–** | – | **–** | – |
| Benefits paid | **(3)** | (3) | **–** | – |
| Foreign exchange rate changes | **(1)** | (4) | **–** | – |
| Bruce B[(1)] | **510** | | **–** | – |
| Plan assets at fair value – end of year | **585** | 57 | **–** | – |
| Funded status – plan deficit | **(94)** | 12 | **(81)** | (2) |
| Unamortized net actuarial loss/(gain) | **125** | 14 | **(5)** | 1 |
| Unamortized past service costs | **1** | – | **–** | – |
| Accrued benefit asset/(liability), net of valuation allowance | **32** | 26 | **(86)** | (1) |

(1) The Company proportionately consolidated Bruce B, on a prospective basis at 31.6 per cent, effective October 31, 2005.

The accrued benefit (asset)/liability, net of valuation allowance of nil, is included in the Company's balance sheet as follows.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Other assets | **32** | 26 | **–** | – |
| Deferred amounts | **–** | – | **(86)** | (1) |
| Total | **32** | 26 | **(86)** | (1) |

Included in the above accrued benefit obligation and fair value of plan assets at year end are the following amounts in respect of plans that are not fully funded.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Accrued benefit obligation | **(645)** | (5) | **(81)** | (2) |
| Fair value of plan assets | **534** | 4 | **–** | – |
| Funded status – plan deficit | **(111)** | (1) | **(81)** | (2) |

The Company's joint ventures' expected contributions for the year ended December 31, 2006 are approximately $27 million for the pension benefit plans and approximately $2 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service.

| *(millions of dollars)* | Pension Benefits | Other Benefits |
|---|---|---|
| 2006 | 11 | 2 |
| 2007 | 13 | 2 |
| 2008 | 16 | 2 |
| 2009 | 20 | 3 |
| 2010 | 24 | 3 |
| Years 2011 to 2015 | 172 | 21 |

The significant weighted average actuarial assumptions adopted in measuring the Company's joint ventures' benefit obligations at December 31 are as follows.

| | Pension Benefit Plans | | Other Benefit Plans | |
|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 |
| Discount rate | **5.30%** | 5.75% | **5.15%** | 5.75% |
| Rate of compensation increase | **3.50%** | 4.00% | | |

The significant weighted average actuarial assumptions adopted in measuring the Company's joint ventures' net benefit plan cost for years ended December 31 are as follows.

| | Pension Benefit Plans | | | Other Benefit Plans | | |
|---|---|---|---|---|---|---|
| | **2005** | 2004 | 2003 | **2005** | 2004 | 2003 |
| Discount rate | **6.20%** | 6.00% | 6.75% | **6.25%** | 6.00% | 6.75% |
| Expected long-term rate of return on plan assets | **7.40%** | 8.50% | 8.80% | | | |
| Rate of compensation increase | **3.50%** | 4.00% | 4.00% | | | |

A one percentage point increase or decrease in assumed health care cost trend rates would have the following effects.

| *(millions of dollars)* | Increase | Decrease |
|---|---|---|
| Effect on total of service and interest cost components | 1 | (1) |
| Effect on post-employment benefit obligation | 7 | (6) |

The Company's proportionate share of net benefit cost of joint ventures is as follows.

| *Year ended December 31 (millions of dollars)* | Pension Benefit Plans **2005** | 2004 | 2003 | Other Benefit Plans **2005** | 2004 | 2003 |
|---|---|---|---|---|---|---|
| Current service cost | **4** | 1 | 1 | **1** | – | – |
| Interest cost | **7** | 3 | 3 | **1** | – | – |
| Actual return on plan assets | **(18)** | (7) | (7) | **–** | – | – |
| Actuarial loss | **17** | – | 4 | **2** | – | – |
| Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost | **10** | (3) | 1 | **4** | – | – |
| Difference between expected and actual return on plan assets | **9** | 2 | 2 | **–** | – | – |
| Difference between actuarial loss recognized and actual actuarial loss on accrued benefit obligation | **(16)** | 1 | (4) | **(3)** | – | – |
| Difference between amortization of past service costs and actual plan amendments | **–** | – | – | **–** | – | – |
| Net benefit cost recognized by joint ventures | **3** | – | (1) | **1** | – | – |

The Company's pension plans' weighted average asset allocations at December 31, by asset category, and weighted average target allocation at December 31, by asset category, is as follows.

| **Asset Category** | Percentage of Plan Assets **2005** | 2004 | **Target Allocation 2005** |
|---|---|---|---|
| Debt securities | **30%** | 38% | **30% to 40%** |
| Equity securities | **70%** | 62% | **60% to 70%** |
| | **100%** | 100% | |

Debt securities include the Company's long-term debt in the amount of $1 million (0.2 per cent of total plan assets) and nil at December 31, 2005 and 2004, respectively. Equity securities include the Company's common shares in the amounts of $5 million (0.9 per cent of total plan assets) and nil at December 31, 2005 and 2004, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

## NOTE 21 CHANGES IN OPERATING WORKING CAPITAL

| *Year ended December 31 (millions of dollars)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| (Increase)/decrease in accounts receivable | **(100)** | 16 | 98 |
| (Increase)/decrease in inventories | **(50)** | – | 15 |
| (Increase)/decrease in other current assets | **(1)** | 24 | 28 |
| Increase/(decrease) in accounts payable | **97** | (4) | (46) |
| Increase/(decrease) in accrued interest | **5** | (7) | (2) |
| | **(49)** | 29 | 93 |

## NOTE 22 COMMITMENTS, CONTINGENCIES AND GUARANTEES

### Commitments

*Operating leases*

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services, equipment and a natural gas storage facility are approximately as follows.

| *Year ended December 31 (millions of dollars)* | Minimum Lease Payments | Amounts Recoverable under Sub-Leases | Net Payments |
|---|---|---|---|
| 2006 | 46 | (12) | 34 |
| 2007 | 52 | (12) | 40 |
| 2008 | 54 | (12) | 42 |
| 2009 | 54 | (11) | 43 |
| 2010 | 53 | (11) | 42 |

The operating lease agreements for premises, services and equipment expire at various dates through 2011, with an option to renew certain lease agreements for five years. The operating lease agreement for the natural gas storage facility expires in 2030 with lessee termination rights every fifth anniversary commencing in 2010 and with the lessor having the right to terminate the agreement every five years commencing in 2015. Net rental expense on operating leases for the year ended December 31, 2005 was $17 million (2004 – $7 million; 2003 – $2 million).

*Bruce Power*

TransCanada's share of Bruce A's signed commitments to third party suppliers for the next five years for the restart and refurbishment of the currently idle Units 1 and 2, extending the operating life of Unit 3 by replacing its steam generators and fuel channels when required and replacing the steam generators on Unit 4, is as follows.

| *Year ended December 31 (millions of dollars)* | |
|---|---|
| 2006 | 322 |
| 2007 | 311 |
| 2008 | 142 |
| 2009 | 69 |
| 2010 | – |
| | 844 |

*Aboriginal Pipeline Group*

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement which governs TransCanada's role in the Mackenzie Gas Pipeline Project. The project would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect with the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project development costs. These costs were originally estimated to be approximately $90 million, but given extended project delays, the protracted regulatory process and the projected timing to reach a decision to construct the pipeline, this share is currently forecasted to increase to approximately $145 million. As at December 31, 2005, TransCanada had funded $87 million (2004 – $60 million) of this loan which is included in other assets. The ability to recover this investment is dependent upon the outcome of the project.

### Contingencies

The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners commenced an action in 2003 under Ontario's Class Proceedings Act, 1992, against TransCanada and Enbridge Inc. for damages of $500 million alleged to arise from the creation of a control zone within 30 metres of the pipeline pursuant to Section 112 of the NEB Act. The Company believes the claim is without merit and will vigorously defend the action. The Company has made no provision for any potential liability. A liability, if any, would be dealt with through the regulatory process.

The Company and its subsidiaries are subject to various other legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of Management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

### Guarantees

The Company, together with Cameco Corporation and BPC Generation Infrastructure Trust (BPC), has severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, the lease agreement and contractor services. The terms of the guarantees range from 2007 to 2018.

As part of the reorganization of Bruce Power, including the formation of Bruce A and the commitment to restart and refurbish the Bruce A units, the Company, together with BPC, severally guaranteed one-half of certain contingent financial obligations of Bruce A related to the refurbishment agreement with the Ontario Power Authority and cost sharing and sublease agreements with Bruce B. The terms of the guarantees currently range from 2018 to 2019.

TransCanada's share of the exposure under these Bruce Power guarantees at December 31, 2005 was estimated to be approximately $652 million of a calculated maximum of $758 million. The current carrying amount of the liability related to these guarantees is nil and the fair value is approximately $17 million.

TransCanada has guaranteed the equity undertaking of a subsidiary which supports the payment, under certain conditions, of principal and interest on US$133 million of public debt obligations of TransGas. The Company has a 46.5 per cent interest in TransGas. Under the terms of the agreement, the Company severally with another major multinational company may be required to fund more than their proportionate share of debt obligations of TransGas in the event that the minority shareholders fail to contribute. Any payments made by TransCanada under this agreement convert into share capital of TransGas. The potential exposure is contingent on the impact of any change of law on TransGas' ability to service the debt. From the issuance of the debt in 1995 to date, there has been no change in applicable law and thus no exposure to TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

In connection with the acquisition of GTN, US$241 million of the purchase price was deposited into an escrow account. As at December 31, 2005, there was US$54 million remaining in the escrow account. The outstanding funds in the escrow account represent the full face amount of the potential liability under certain GTN guarantees and are to be used to satisfy the liability of GTN under these designated guarantees.

## NOTE 23 DISCONTINUED OPERATIONS

The Board of Directors approved plans in previous years to dispose of the Company's International, Canadian Midstream, Gas Marketing and certain other businesses. Net income from discontinued operations for the year ended December 31, 2005 was nil (2004 – $52 million, net of $27 million of income taxes; 2003 – $50 million, net of $29 million of income taxes). Included in accounts payable at December 31, 2005 was the remaining $51 million provision for loss on discontinued operations (2004 – $55 million).