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 *(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

	2005			2004		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	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) *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
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 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) *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)[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			Other Benefit Plans		
	2005	2004	2003	**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.

	Percentage of Plan Assets		**Target Allocation**
Asset Category	**2005**	2004	**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).