

TRANSCANADA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

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

Pipelines

The Pipelines segment consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities. Through its Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta (Alberta System);
- a natural gas transmission system extending from producing fields located primarily in Oklahoma, Texas, Louisiana and the Gulf of Mexico to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the British Columbia (B.C.)/Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon (GTN System);
- a natural gas transmission system extending from central Alberta to the B.C./United States border and to the Saskatchewan/U.S. border (Foothills);
- a natural gas transmission system extending from Arizona to the Baja California, Mexico/California border (North Baja);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale);
- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S. (Great Lakes);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline and transports natural gas in Québec, from Montreal to the Portland system and to Québec City (TQM); and
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec to the northeastern U.S. (Portland).
- a 32.1 per cent interest in TC PipeLines, LP (PipeLines LP), which owns the following pipelines operated by TransCanada:
 - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 68.5 per cent effective ownership interest through PipeLines LP and a direct interest described above;
 - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 16.1 per cent effective ownership interest through PipeLines LP; and
 - 100 per cent of a natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 32.1 per cent effective ownership interest through PipeLines LP.

TransCanada owns but does not operate:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system, extending from Mariquita in the central region of Colombia to Cali in the southwest region of Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

TransCanada has a 62 per cent interest in a pipeline under construction that will transport crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and at Cushing, Oklahoma (Keystone).

Energy

The Energy segment consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company also sells electricity and holds interests in liquefied natural gas (LNG) regasification projects in North America. Through its Energy segment, TransCanada owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview); and
- a natural gas storage facility near Edson, Alberta (Edson).

TransCanada owns but does not operate:

- a 48.9 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) (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of six planned wind farms in Gaspé, Québec (Cartier Wind); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

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

- 100 per cent of the production of the Sundance A power facilities and, through a partnership, 50 per cent of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 756 megawatts (MW) of the generating capacity from the Sheerness power facility near Hanna, Alberta.

TransCanada has interests in the following projects under construction:

- a 50 per cent interest in a natural gas-fired, combined-cycle cogeneration plant near downtown Toronto, Ontario (Portlands Energy);
- a natural gas-fired, combined-cycle power plant near Toronto (Halton Hills); and
- a wind power project located in Kibby and Skinner Townships in northwestern Franklin County, Maine (Kibby Wind).

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with Canadian GAAP. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses as the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. 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 and its subsidiaries. The Company consolidates its 32.1 per cent ownership interest in PipeLines LP and its 61.7 per cent interest in the Portland Natural Gas Transmission System (Portland) as the Company is able to exercise control over these assets. The other partners' interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian Mainline, Foothills Pipe Lines Ltd. (Foothills) and Trans Québec & Maritimes System (TQM) are subject to the authority of the National Energy Board (NEB) of Canada. The Alberta System is regulated by the Alberta Utilities Commission (AUC). The GTN System and North Baja (collectively, GTN), the ANR Pipeline Company, the ANR Storage Company and the other natural gas pipelines in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). These natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these regulated businesses may differ from that otherwise expected under GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. The impact of rate regulation on TransCanada is provided in Note 14 of these financial statements.

Revenue Recognition

Pipelines

In the Pipelines segment, revenues from Canadian operations subject to rate regulation are recognized in accordance with decisions made by the NEB and AUC. Revenues from U.S. operations subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. For interruptible or volumetric-based services, revenues are recorded when physical delivery is made. As the majority of the Company's natural gas pipelines are subject to rate regulation, revenues collected that are subject to rate proceedings may have to be refunded. Revenues from non-regulated operations are recorded when products have been delivered or services have been performed.

Energy

i) Power

Revenues from the Company's Power business are primarily derived from the sale of electricity from energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded in the month of delivery. Revenues also include capacity payments and ancillary services earned as well as the impact of energy derivative contracts, the accounting for which is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Effective April 1, 2007, the Company adopted the accounting requirements for the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031 "Inventories". Inventories primarily consist of materials and supplies, including spare parts, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas, less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of the proprietary natural gas inventories are reflected in Inventories and Revenues.

Plant, Property and Equipment

Pipelines

Plant, property and equipment of the Pipelines segment are carried at cost. Depreciation is calculated on a straight-line basis. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to 25 per cent and metering and other plant equipment are depreciated at various rates. The cost of regulated pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets on the balance sheet. Interest is capitalized during construction of non-regulated pipelines. The equity component of AFUDC is a non-cash expenditure.

When regulated pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Energy

Major power generation and natural gas storage plant, equipment and structures in the Energy segment are recorded at cost and depreciated on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to ten per cent. Nuclear power generation assets under capital lease are recorded initially 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 and the 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 facilities 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.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as property, plant and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. Goodwill is not amortized and is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The initial payments for a PPA are deferred and amortized on a straight-line basis over the term of the contract, with remaining terms ranging from nine to 12 years. The PPAs under which TransCanada buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options

TransCanada's Stock Option Plan permits options to be awarded to certain employees, including officers, to purchase common shares. The contractual life of options granted in 2003 and thereafter and options granted prior to 2003 is seven years and ten years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeitures of stock options result from their expiration or from the resignation, retirement or termination of the option holder. Stock options become null and void upon forfeiture. The Company records compensation expense over the three-year vesting period, assuming a

15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in the results of the Pipelines and Energy segments. Upon exercise of stock options, adjusted for stock options forfeited, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The taxes payable method of accounting for income taxes is used for tollmaking purposes for Canadian regulated natural gas transmission operations, as prescribed by regulators. It is not necessary to provide for future income taxes under the taxes payable method. As permitted by Canadian GAAP at December 31, 2008, 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 that time. The liability method of accounting for income taxes is used for all of the Company's other operations. Under the liability method, future income 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 anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that 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 consolidated statements of income, shareholders' equity, comprehensive income, accumulated other comprehensive income and cash flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income.

Exchange gains or losses on monetary assets and liabilities are recorded in income except for exchange gains or losses on the principal amounts of foreign currency debt related to the Alberta System, Foothills and Canadian Mainline, which are deferred until they are refunded or recovered in tolls, as permitted by regulatory bodies.

Financial Instruments

Effective January 1, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 1530 "Comprehensive Income", 3855 "Financial Instruments – Recognition and Measurement", and 3865 "Hedges". Effective December 31, 2007, the Company adopted the accounting requirements for CICA Handbook Sections 3862 "Financial Instruments – Disclosure", 3863 "Financial Instruments – Presentation", and 1535 "Capital Disclosures". Adjustments to the consolidated financial statements for 2007 were made on a prospective basis.

The CICA Handbook requires that all financial instruments initially be included on the balance sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments and loans and receivables. Financial liabilities are classified as held for trading or other financial liabilities.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading if it is entered into with the intention of generating a profit. The Company has not designated any non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Changes in the fair value of interest rate and foreign exchange rate held-for-trading instruments are recorded in Financial Charges and in Interest Income and Other, respectively.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are accounted for initially at their fair value and changes to fair value are recorded through Other Comprehensive Income. Income from the settlement of available-for-sale financial assets will be included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as "loans and receivables" and are measured at amortized cost using the effective interest method, net of any impairment. Loans and receivables include primarily trade accounts receivable and non-interest-bearing third-party loans receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest expense is included in Financial Charges and in Financial Charges of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the balance sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements. Changes in fair value of derivatives that are not designated in a hedging relationship are recorded in Net Income. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in the fair value of embedded derivatives that are recorded separately are included in Net Income.

The recognition of gains and losses on the derivatives for the Alberta System, Foothills and Canadian Mainline exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of rate-regulated accounting are deferred in regulatory assets or regulatory liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair values of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Property, Plant and Equipment or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The CICA Handbook specifies the criteria that must be satisfied in order to apply hedge accounting and the accounting for each of the permitted hedging strategies, including: fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

Documentation must be prepared at the inception of the hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company must perform an assessment of effectiveness at inception of the contract and at each reporting date.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. The changes in fair value are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Financial Charges, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in Other Comprehensive Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from Accumulated Other Comprehensive Income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from the changes in fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as rate-regulated assets or liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains or losses are collected from or refunded to the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive Income and the ineffective portion is recognized in Net

Income. The amounts recognized previously in Accumulated Other Comprehensive Income are reclassified to Net Income in the event the Company settles or otherwise reduces its investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred, when a legal obligation to do so exists and 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.

It is not possible to determine the scope and timing of asset retirements related to regulated natural gas pipelines and, therefore, it is not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to regulated natural gas pipelines, with the exception of certain abandoned facilities. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through tolls in future periods.

Similarly, it is not possible to determine the scope and timing of asset retirements related to hydroelectric power plants and, therefore, it is not possible to make a reasonable estimate of the fair value of the associated liability. As a result, the Company has not recorded an amount for asset retirement obligations related to hydroelectric power plants. With respect to the nuclear assets leased by Bruce Power, the Company has not recorded an amount for asset retirement obligations, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Any amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contributions plans (DC Plans), a Savings Plan and other post-employment plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed as incurred. The cost of the DB Plans and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plan's assets. Past service costs are amortized over the expected average remaining service life of the employees. 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 net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, 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 medium-term incentive plans, which are payable in cash to eligible employees. 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 employees' continued employment during a specified period and achievement of specified corporate performance targets.

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

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

Rate-Regulated Operations

Effective January 1, 2009, the temporary exemption from CICA Handbook Section 1100 "Generally Accepted Accounting Principles", which permits the recognition and measurement of assets and liabilities arising from rate regulation, was withdrawn. In addition, Section 3465 "Income Taxes" was amended to require the recognition of future income tax assets and liabilities for rate-regulated entities. The Company has chosen to adopt accounting policies consistent with the U.S. Financial Accounting Standards Board's Financial Accounting Standard (FAS) 71 "Accounting for the Effects of Certain Types of Regulation". Accordingly, TransCanada will retain its current method of accounting for its

rate-regulated operations, except that TransCanada will be required to recognize future income tax assets and liabilities instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. If the Company had adopted FAS 71, at December 31, 2008, additional future income tax liabilities and a regulatory asset in the amount of \$1,434 million would have been recorded and would have been recoverable from future revenue. These changes will be applied retrospectively without restatement beginning January 1, 2009.

Intangible Assets

The CICA Handbook implemented revisions to standards dealing with intangible assets effective for fiscal years beginning on or after October 1, 2008. The revisions are intended to align the definition of an intangible asset in Canadian GAAP with that in International Financial Reporting Standards (IFRS) and U.S. GAAP. CICA Handbook Section 1000 "Financial Statement Concepts" was revised to remove material that permitted the recognition of assets that might not otherwise meet the definition of an asset and to add guidance from the International Accounting Standards Board's (IASB) "Framework for the Preparation and Presentation of Financial Statements" that helps distinguish assets from expenses. CICA Handbook Section 3064 "Goodwill and Intangible Assets", which replaced CICA Handbook Section 3062 "Goodwill and Other Intangible Assets", gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. In addition, CICA Handbook Section 3450 "Research and Development Costs" will be withdrawn from the Handbook. The Company does not expect these changes to have a material effect on its financial statements.

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

CICA Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". These standards will require a change in the measurement of non-controlling interest and will require the change to be presented as part of shareholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling interest and non-controlling interest. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board announced that Canadian publicly accountable enterprises are required to adopt IFRS, as issued by the IASB, effective January 1, 2011. In June 2008, the Canadian Securities Administrators proposed that Canadian public companies that are also U.S. Securities and Exchange Commission (SEC) registrants, such as TransCanada, retain the option to prepare their financial statements under U.S. GAAP instead of IFRS. In November 2008, the SEC issued for public comment a recommendation that, beginning in 2014, U.S. issuers be required to adopt IFRS using a phased-in approach based on market capitalization.

TransCanada is currently considering the impact a conversion to IFRS or U.S. GAAP would have on its accounting systems and financial statements. TransCanada's conversion project planning includes an analysis of project structure and governance, resources and training, analysis of key GAAP differences and a phased approach to the assessment of current accounting policies and implementation.

Under existing Canadian GAAP, TransCanada follows specific accounting policies unique to rate-regulated businesses. TransCanada is actively monitoring ongoing discussions and developments at the IASB regarding potential future guidance to clarify the applicability of certain aspects of rate-regulated accounting under IFRS. The IASB is expected to issue a proposed standard for rate-regulated businesses in 2009.

NOTE 4 SEGMENTED INFORMATION**NET INCOME⁽¹⁾***Year ended December 31, 2008 (millions of dollars)*

| | Pipelines | Energy | Corporate | Total |
|---|------------|------------|-------------|--------------|
| Revenues | 4,650 | 3,969 | – | 8,619 |
| Plant operating costs and other | (1,732) | (1,326) | (4) | (3,062) |
| Commodity purchases resold | – | (1,511) | – | (1,511) |
| Depreciation | (989) | (200) | – | (1,189) |
| | 1,929 | 932 | (4) | 2,857 |
| Financial charges | (674) | – | (269) | (943) |
| Financial charges of joint ventures | (49) | (23) | – | (72) |
| Interest income and other | 73 | 6 | 13 | 92 |
| Calpine bankruptcy settlements | 279 | – | – | 279 |
| Writedown of Broadwater LNG project costs | – | (41) | – | (41) |
| Income taxes | (548) | (260) | 206 | (602) |
| Non-controlling interests | (108) | – | (22) | (130) |
| Net Income | 902 | 614 | (76) | 1,440 |

Year ended December 31, 2007 (millions of dollars)

| | | | | |
|-------------------------------------|------------|------------|-----------|--------------|
| Revenues | 4,712 | 4,116 | – | 8,828 |
| Plant operating costs and other | (1,670) | (1,353) | (7) | (3,030) |
| Commodity purchases resold | (72) | (1,887) | – | (1,959) |
| Depreciation | (1,021) | (158) | – | (1,179) |
| | 1,949 | 718 | (7) | 2,660 |
| Financial charges | (718) | 1 | (226) | (943) |
| Financial charges of joint ventures | (52) | (23) | – | (75) |
| Interest income and other | 52 | 10 | 90 | 152 |
| Gain on sale of assets | – | 16 | – | 16 |
| Income taxes | (470) | (208) | 188 | (490) |
| Non-controlling interests | (75) | – | (22) | (97) |
| Net Income | 686 | 514 | 23 | 1,223 |

Year ended December 31, 2006 (millions of dollars)

| | | | | |
|---|---------|---------|-------|--------------|
| Revenues | 3,990 | 3,530 | – | 7,520 |
| Plant operating costs and other | (1,380) | (1,024) | (7) | (2,411) |
| Commodity purchases resold | – | (1,707) | – | (1,707) |
| Depreciation | (927) | (131) | (1) | (1,059) |
| | 1,683 | 668 | (8) | 2,343 |
| Financial charges | (711) | – | (114) | (825) |
| Financial charges of joint ventures | (69) | (23) | – | (92) |
| Interest income and other | 100 | 5 | 51 | 156 |
| Gain on sale of assets | 23 | – | – | 23 |
| Income taxes | (410) | (198) | 132 | (476) |
| Non-controlling interests | (56) | – | (22) | (78) |
| Net income from continuing operations | 560 | 452 | 39 | 1,051 |
| Net income from discontinued operations | | | | 28 |
| Net Income | | | | 1,079 |

⁽¹⁾ Certain expenses such as indirect financial charges and related income taxes are not allocated to business segments when determining their net income.

TOTAL ASSETS

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|--|---------------|--------|
| Pipelines | 25,020 | 22,024 |
| Energy | 12,006 | 7,037 |
| Corporate | 2,388 | 1,269 |
| | 39,414 | 30,330 |

GEOGRAPHIC INFORMATION

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|-------|-------|
| Revenues⁽¹⁾ | | | |
| Canada – domestic | 4,599 | 5,019 | 4,956 |
| Canada – export | 1,125 | 1,006 | 972 |
| United States and other | 2,895 | 2,803 | 1,592 |
| | 8,619 | 8,828 | 7,520 |

⁽¹⁾ Revenues are attributed based on the country where the product or service originated.

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|--|---------------|--------|
| Plant, Property and Equipment | | |
| Canada | 18,041 | 16,741 |
| United States | 10,973 | 6,564 |
| Mexico | 175 | 147 |
| | 29,189 | 23,452 |

CAPITAL EXPENDITURES

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|-------|-------|
| Pipelines | 1,854 | 564 | 560 |
| Energy | 1,266 | 1,079 | 976 |
| Corporate | 14 | 8 | 36 |
| | 3,134 | 1,651 | 1,572 |

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

| December 31 (millions of dollars) | 2008 | | | 2007 | | |
|---|---------------|--------------------------|----------------|--------------------|--------------------------|----------------|
| | Cost | Accumulated Depreciation | Net Book Value | Cost | Accumulated Depreciation | Net Book Value |
| Pipelines⁽¹⁾ | | | | | | |
| Canadian Mainline | | | | | | |
| Pipeline | 8,740 | 4,269 | 4,471 | 8,889 | 4,149 | 4,740 |
| Compression | 3,373 | 1,399 | 1,974 | 3,371 | 1,303 | 2,068 |
| Metering and other | 344 | 140 | 204 | 345 | 140 | 205 |
| | 12,457 | 5,808 | 6,649 | 12,605 | 5,592 | 7,013 |
| Under construction | 16 | – | 16 | 28 | – | 28 |
| | 12,473 | 5,808 | 6,665 | 12,633 | 5,592 | 7,041 |
| Alberta System | | | | | | |
| Pipeline | 5,518 | 2,637 | 2,881 | 5,258 | 2,504 | 2,754 |
| Compression | 1,552 | 914 | 638 | 1,522 | 842 | 680 |
| Metering and other | 846 | 317 | 529 | 831 | 297 | 534 |
| | 7,916 | 3,868 | 4,048 | 7,611 | 3,643 | 3,968 |
| Under construction | 354 | – | 354 | 120 | – | 120 |
| | 8,270 | 3,868 | 4,402 | 7,731 | 3,643 | 4,088 |
| ANR | | | | | | |
| Pipeline | 976 | 69 | 907 | 772 | 25 | 747 |
| Compression | 579 | 61 | 518 | 424 | 32 | 392 |
| Metering and other | 686 | 50 | 636 | 483 | 6 | 477 |
| | 2,241 | 180 | 2,061 | 1,679 | 63 | 1,616 |
| Under construction | 31 | – | 31 | 69 | – | 69 |
| | 2,272 | 180 | 2,092 | 1,748 | 63 | 1,685 |
| GTN | | | | | | |
| Pipeline | 1,482 | 215 | 1,267 | 1,181 | 134 | 1,047 |
| Compression | 562 | 63 | 499 | 436 | 39 | 397 |
| Metering and other | 134 | 23 | 111 | 81 | 3 | 78 |
| | 2,178 | 301 | 1,877 | 1,698 | 176 | 1,522 |
| Under construction | 30 | – | 30 | 31 | – | 31 |
| | 2,208 | 301 | 1,907 | 1,729 | 176 | 1,553 |
| Great Lakes | 1,875 | 744 | 1,131 | 1,509 | 552 | 957 |
| Foothills | 1,655 | 873 | 782 | 1,647 | 819 | 828 |
| Northern Border | 1,530 | 682 | 848 | 1,232 | 528 | 704 |
| Keystone – under construction | 1,361 | – | 1,361 | 158 | – | 158 |
| Other ⁽²⁾ | 2,078 | 566 | 1,512 | 1,705 | 439 | 1,266 |
| | 8,499 | 2,865 | 5,634 | 6,251 | 2,338 | 3,913 |
| | 33,722 | 13,022 | 20,700 | 30,092 | 11,812 | 18,280 |
| Energy | | | | | | |
| Nuclear ⁽³⁾ | 1,604 | 364 | 1,240 | 1,479 | 286 | 1,193 |
| Natural gas/oil – Ravenswood ⁽⁴⁾ | 1,977 | 22 | 1,955 | n/a ⁽⁵⁾ | n/a | n/a |
| Natural gas – Other ⁽⁶⁾ | 1,702 | 504 | 1,198 | 1,570 | 383 | 1,187 |
| Hydro | 628 | 48 | 580 | 503 | 28 | 475 |
| Wind | 391 | 18 | 373 | 288 | 6 | 282 |
| Natural gas storage | 374 | 46 | 328 | 358 | 33 | 325 |
| Other | 156 | 82 | 74 | 137 | 78 | 59 |
| | 6,832 | 1,084 | 5,748 | 4,335 | 814 | 3,521 |
| Under construction ⁽⁷⁾ | 2,687 | – | 2,687 | 1,606 | – | 1,606 |
| | 9,519 | 1,084 | 8,435 | 5,941 | 814 | 5,127 |
| Corporate | 74 | 20 | 54 | 60 | 15 | 45 |
| | 43,315 | 14,126 | 29,189 | 36,093 | 12,641 | 23,452 |

(1) In 2008, the Company capitalized \$27 million (2007 – \$14 million) relating to AFUDC.

(2) Pipelines – Other primarily includes assets of Iroquois, Portland, TQM, Tuscarora and Tamazunchale.

(3) Includes assets under capital lease relating to Bruce Power.

(4) TransCanada acquired Ravenswood on August 26, 2008.

(5) Not applicable, as there are no comparative amounts for prior years.

(6) Certain owned power generation facilities with long-term PPAs are accounted for as assets under operating leases. The net book value of these facilities was \$77 million at December 31, 2008 (2007 – \$78 million). Revenues of \$14 million were recognized in 2008 (2007 – \$16 million) through the sale of electricity under the related PPAs.

(7) Energy assets under construction primarily include expenditures for the Bruce A refurbishment and restart, and for construction of Halton Hills, Portland Energy, Kibby Wind and Coolidge.

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

| <i>(millions of dollars)</i> | Pipelines | Energy | Total |
|--|--------------|--------------|--------------|
| Balance at January 1, 2007 | 281 | – | 281 |
| Acquisition of ANR | 2,235 | – | 2,235 |
| Acquisition of additional interests in Great Lakes | 573 | – | 573 |
| Acquisition of additional interest in Tuscarora | 3 | – | 3 |
| Foreign exchange and adjustments | (459) | – | (459) |
| Balance at December 31, 2007 | 2,633 | – | 2,633 |
| Acquisition of Ravenswood | – | 949 | 949 |
| Foreign exchange and adjustments | 749 | 66 | 815 |
| Balance at December 31, 2008 | 3,382 | 1,015 | 4,397 |

NOTE 7 OTHER ASSETS

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|---|--------------|-------|
| PPAs ⁽¹⁾ | 651 | 709 |
| Prepaid operating lease ⁽²⁾ | 369 | n/a |
| Pension and other benefit plans (Note 21) | 234 | 234 |
| Regulatory assets (Note 14) | 201 | 336 |
| Fair value of derivative contracts (Note 17) | 191 | 204 |
| Loans and advances ⁽³⁾ (Note 23) | 140 | 137 |
| Deferred project development costs ⁽⁴⁾ | 116 | 40 |
| Equity investments ⁽⁵⁾ | 85 | 63 |
| Other | 241 | 217 |
| | 2,228 | 1,940 |

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

| <i>December 31 (millions of dollars)</i> | 2008 | | | 2007 | | |
|--|------|--------------------------|----------------|------|--------------------------|----------------|
| | Cost | Accumulated Amortization | Net Book Value | Cost | Accumulated Amortization | Net Book Value |
| PPAs | 915 | 264 | 651 | 915 | 206 | 709 |

Amortization expense for the PPAs was \$58 million for the year ended December 31, 2008 (2007 – \$58 million; 2006 – \$58 million). The expected annual amortization expense in each of the next five years is: 2009 – \$58 million; 2010 – \$58 million; 2011 – \$57 million; 2012 – \$57 million; and 2013 – \$57 million.

(2) The balance at December 31, 2008 represents the long-term portion of a prepaid operating lease from the acquisition of Ravenswood. The expected annual operating lease expense in each of the next five years is US\$10 million.

(3) The balance at December 31, 2008 represents a \$140-million loan (2007 – \$137 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. The ability to recover this investment remains dependent upon the successful outcome of the project.

(4) The balance at December 31, 2008 includes \$74 million (2007 – nil) related to the proposed expansion of the Keystone pipeline project and \$42 million related to the Bison pipeline project. The balance of \$40 million at December 31, 2007 related to the Broadwater LNG project and, in 2008, TransCanada wrote down \$41 million of capitalized costs related to this project after the New York Department of State rejected a proposal to construct this facility.

(5) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

NOTE 8 JOINT VENTURE INVESTMENTS

| <i>(millions of dollars)</i> | Ownership Interest as at December 31, 2008 | TransCanada's Proportionate Share | | | | |
|--------------------------------|--|---|------|------|---------------------------|-------|
| | | Income/(Loss) Before Income Taxes Year ended December 31 | | | Net Assets December 31 | |
| | | 2008 | 2007 | 2006 | 2008 | 2007 |
| Pipelines | | | | | | |
| Northern Border ⁽¹⁾ | | 59 | 67 | 52 | 479 | 415 |
| Iroquois | 44.5% | 32 | 25 | 25 | 239 | 163 |
| TQM | 50.0% | 12 | 11 | 11 | 69 | 74 |
| Keystone | 61.9% ⁽²⁾ | (7) | n/a | n/a | 906 | 207 |
| Great Lakes ⁽³⁾ | | – | 13 | 69 | – | – |
| Other | Various | 15 | 13 | 6 | 70 | 48 |
| Energy | | | | | | |
| Bruce A | 48.9% | 46 | 8 | 75 | 2,012 | 1,640 |
| Bruce B | 31.6% | 136 | 140 | 140 | 429 | 325 |
| CrossAlta | 60.0% | 44 | 59 | 64 | 56 | 38 |
| Cartier Wind | 62.0% ⁽⁴⁾ | 12 | 10 | 2 | 365 | 275 |
| TC Turbines | 50.0% | 9 | 5 | 5 | 31 | 29 |
| Portlands Energy | 50.0% | – | – | – | 334 | 269 |
| ASTC Power Partnership | 50.0% ⁽⁵⁾ | – | – | – | 70 | 76 |
| | | 358 | 351 | 449 | 5,060 | 3,559 |

(1) PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border in April 2006, increasing its general partnership interest to 50 per cent. Through TransCanada's 32.1 per cent ownership interest in PipeLines LP, Northern Border became a jointly controlled entity and TransCanada commenced proportionately consolidating its investment in Northern Border on a prospective basis. The Company's effective ownership of Northern Border, net of non-controlling interests, was 16.1 per cent at December 31, 2008 and 2007.

(2) In December 2007, ConocoPhillips exercised its option to become a 50 per cent partner with TransCanada in Keystone. As a result, TransCanada transferred \$207 million of net assets and ConocoPhillips contributed \$207 million of cash to each become a 50 per cent joint venture partner in Keystone. In 2008, TransCanada agreed to increase its equity ownership in the Keystone partnerships to 79.99 per cent. ConocoPhillips' equity ownership will be reduced concurrently to 20.01 per cent. TransCanada's increase in ownership is expected to occur as the Company funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. At December 31, 2008, TransCanada's equity ownership in the Keystone partnerships was 61.9 per cent (December 31, 2007 – 50.0 per cent), however, strategic, operational and financial decisions are made jointly with ConocoPhillips.

(3) In February 2007, TransCanada acquired an additional 3.6 per cent interest in Great Lakes, bringing its direct ownership interest to 53.6 per cent, and PipeLines LP acquired a 46.4 per cent interest in Great Lakes, giving TransCanada an indirect 14.9 per cent interest in Great Lakes. As a result of these transactions, the Company's effective ownership interest in Great Lakes, net of non-controlling interests, was 68.5 per cent at December 31, 2008 and 2007. TransCanada commenced consolidating its investment in Great Lakes on a prospective basis effective February 22, 2007.

(4) TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The first three phases of the six-phase Cartier Wind project, Baie-des-Sables, Anse-à-Valleau and Carleton, began operating in November 2006, 2007 and 2008, respectively.

(5) The Company has a 50 per cent ownership interest in ASTC Power Partnership, an Alberta partnership which holds the Sundance B PPA. The underlying power volumes related to this ownership interest are effectively transferred to TransCanada.

Summarized Financial Information of Joint Ventures

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|-------|-------|
| Income | | | |
| Revenues | 1,264 | 1,305 | 1,382 |
| Plant operating costs and other | (683) | (736) | (686) |
| Depreciation | (154) | (150) | (163) |
| Financial charges and other | (69) | (68) | (84) |
| Proportionate share of joint venture income before income taxes | 358 | 351 | 449 |

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|----------------|-------|-------|
| Cash Flows | | | |
| Operating activities | 1,067 | 420 | 645 |
| Investing activities | (2,031) | (761) | (641) |
| Financing activities ⁽¹⁾ | 952 | 409 | (31) |
| Effect of foreign exchange rate changes on cash and cash equivalents | 23 | (8) | 9 |
| Proportionate share of increase/(decrease) in cash and cash equivalents of joint ventures | 11 | 60 | (18) |

⁽¹⁾ Financing activities included cash outflows resulting from distributions paid to TransCanada of \$287 million in 2008 (2007 – \$361 million; 2006 – \$470 million) and cash inflows resulting from capital contributions paid by TransCanada of \$1,067 million in 2008 (2007 – \$771 million; 2006 – \$452 million).

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|---|--------------|-------|
| Balance Sheet | | |
| Cash and cash equivalents | 181 | 170 |
| Other current assets | 159 | 343 |
| Plant, property and equipment | 6,341 | 4,283 |
| Other assets/(deferred amounts), net | 45 | (69) |
| Current liabilities | (793) | (293) |
| Long-term debt | (871) | (873) |
| Future income taxes | (2) | (2) |
| Proportionate share of net assets of joint ventures | 5,060 | 3,559 |

NOTE 9 ACQUISITIONS AND DISPOSITIONS**Acquisitions****Pipelines****Keystone**

In 2008, TransCanada agreed to increase its equity ownership in the Keystone partnerships up to 79.99 per cent from 50 per cent, with ConocoPhillips' equity ownership being reduced concurrently to 20.01 per cent. The increase in ownership is expected to occur as TransCanada funds 100 per cent of the construction expenditures until the participants' project capital contributions are aligned with the revised ownership interests. In accordance with the agreement, TransCanada funded \$362 million of cash calls, resulting in the acquisition of an incremental 12 per cent ownership interest for \$176 million, bringing TransCanada's ownership interest to 62 per cent at December 31, 2008. TransCanada continues to proportionately consolidate the Keystone partnerships.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of \$65 million, with no gain recognized on the sale.

ANR and Great Lakes

On February 22, 2007, TransCanada acquired from El Paso Corporation 100 per cent of American Natural Resources Company and ANR Storage Company (collectively, ANR) and an additional 3.6 per cent interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes) for a total of US\$3.4 billion, including US\$491 million of assumed long-term debt. The acquisitions were accounted for using the purchase method of accounting. TransCanada began consolidating ANR and Great Lakes in the Pipelines segment after the acquisition date. The purchase price was allocated as follows:

Purchase Price Allocation

| <i>(millions of US dollars)</i> | ANR | Great Lakes | Total |
|---------------------------------|-------|-------------|-------|
| Current assets | 250 | 4 | 254 |
| Plant, property and equipment | 1,617 | 35 | 1,652 |
| Other non-current assets | 83 | – | 83 |
| Goodwill | 1,945 | 32 | 1,977 |
| Current liabilities | (179) | (3) | (182) |
| Long-term debt | (475) | (16) | (491) |
| Other non-current liabilities | (357) | (19) | (376) |
| | 2,884 | 33 | 2,917 |

TC PipeLines, LP Acquisition of Interest in Great Lakes

On February 22, 2007, PipeLines LP acquired from El Paso Corporation a 46.4 per cent interest in Great Lakes for US\$942 million, including US\$209 million of assumed long-term debt. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Great Lakes in the Pipelines segment after the acquisition date. As of February 2007, TransCanada's effective ownership interest in Great Lakes was 68.5 per cent, comprising its direct ownership interest and its indirect ownership interest through PipeLines LP. The purchase price was allocated as follows:

Purchase Price Allocation

| <i>(millions of US dollars)</i> | |
|---------------------------------|-------|
| Current assets | 42 |
| Plant, property and equipment | 465 |
| Other non-current assets | 1 |
| Goodwill | 457 |
| Current liabilities | (23) |
| Long-term debt | (209) |
| | 733 |

The allocation of the purchase price for these transactions was made using the fair value of the net assets at the date of acquisition. Tolls charged by ANR and Great Lakes are subject to rate regulation based on historical costs. As a result, the regulated net assets, other than ANR's gas held for sale, were determined to have a fair value equal to their rate-regulated value.

Factors that contributed to goodwill included the opportunity to expand in the U.S. market and to gain a stronger competitive position in the North American gas transmission business. Goodwill related to TransCanada's ANR and Great Lakes transactions is not amortizable for tax purposes. Goodwill related to PipeLines LP's Great Lakes transaction is amortizable for tax purposes.

TC PipeLines, LP Private Placement Offering

In February 2007, PipeLines LP completed a private placement offering of 17,356,086 common units at a price of US\$34.57 per unit. TransCanada acquired 50 per cent of the units for US\$300 million. TransCanada also invested an additional US\$12 million to maintain its general partnership interest in PipeLines LP. As a result of these additional investments, TransCanada's ownership in PipeLines LP increased to 32.1 per cent on February 22, 2007. The total private placement, together with TransCanada's additional investment, resulted in gross proceeds to PipeLines LP of US\$612 million, which were used to partially finance its acquisition of a 46.4 per cent ownership interest in Great Lakes.

Tuscarora

In December 2007, PipeLines LP exercised its option to purchase Sierra Pacific Resources' remaining one per cent interest in Tuscarora Gas Transmission Company (Tuscarora) for US\$2 million. In addition, PipeLines LP purchased TransCanada's one per cent interest in Tuscarora for US\$2 million. Beginning December 2007, PipeLines LP owned 100 per cent of Tuscarora, resulting in TransCanada's effective ownership of 32.1 per cent, net of non-controlling interests.

In December 2006, PipeLines LP acquired an additional 49 per cent controlling general partner interest in Tuscarora for US\$100 million in addition to indirectly assuming US\$37 million of debt. The purchase price was allocated US\$79 million to Goodwill, US\$37 million to Long-Term Debt, and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes. PipeLines LP began consolidating its investment in Tuscarora in December 2006.

Northern Border

In April 2006, PipeLines LP acquired an additional 20 per cent general partnership interest in Northern Border Pipeline Company (Northern Border) for US\$307 million, in addition to indirectly assuming US\$122 million of debt. The purchase price was allocated US\$114 million to Goodwill, US\$122 million to Long-Term Debt and the balance primarily to Plant, Property and Equipment. Factors that contributed to goodwill included opportunities for expansion and a stronger competitive position. The goodwill recognized on this transaction is amortizable for tax purposes. As of April 2006, PipeLines LP owned 50 per cent of Northern Border, giving TransCanada effective ownership of 16.1 per cent, net of non-controlling interests.

Energy

Ravenswood

On August 26, 2008, TransCanada acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US\$2.9 billion, subject to certain post-closing adjustments. The acquisition was accounted for using the purchase method of accounting. TransCanada began consolidating Ravenswood in the Energy segment subsequent to the acquisition date. The preliminary allocation of the purchase price at December 31, 2008 was as follows:

Purchase Price Allocation

(millions of US dollars)

| | |
|-------------------------------|--------------|
| Current assets | 149 |
| Plant, property and equipment | 1,666 |
| Other non-current assets | 305 |
| Goodwill | 835 |
| Current liabilities | (19) |
| Other non-current liabilities | (20) |
| | <u>2,916</u> |

A preliminary allocation of the purchase price, subject to certain post-closing adjustments, has been made using fair values of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further in the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on this transaction is amortizable for tax purposes.

Dispositions

Pipelines

Northern Border Partners, L.P. Interest

In April 2006, TransCanada sold its 17.5 per cent general partner interest in Northern Border Partners, L.P., generating net proceeds of \$33 million (US\$30 million) and recognizing an after-tax gain of \$13 million. The net gain was recorded in the Pipelines segment and the Company recorded a \$10 million income tax charge on the transaction, including \$12 million of current income tax expense.

Energy

Ontario Land Sale

In November 2007, TransCanada's Energy segment sold land in Ontario that had previously been held for development, generating net proceeds of \$37 million and recognizing an after-tax gain of \$14 million on the sale.

NOTE 10 LONG-TERM DEBT

| Outstanding loan amounts (millions of dollars unless otherwise indicated) | Maturity Dates | 2008 | | 2007 | |
|---|----------------|-------------------------|------------------------------|-------------------------|------------------------------|
| | | Outstanding December 31 | Interest Rate ⁽¹⁾ | Outstanding December 31 | Interest Rate ⁽¹⁾ |
| TRANSCANADA PIPELINES LIMITED | | | | | |
| Debtures | | | | | |
| Canadian dollars | 2009 to 2020 | 1,251 | 10.8% | 1,351 | 10.9% |
| U.S. dollars (2008 and 2007 – US\$600) ⁽²⁾ | 2012 to 2021 | 734 | 9.5% | 594 | 9.5% |
| Medium-Term Notes | | | | | |
| Canadian dollars ⁽³⁾ | 2009 to 2031 | 3,653 | 5.3% | 3,413 | 6.1% |
| Senior Unsecured Notes | | | | | |
| U.S. dollars (2008 – US\$4,723; 2007 – US\$3,223) ⁽⁴⁾ | 2009 to 2038 | 5,751 | 6.3% | 3,161 | 6.0% |
| | | <u>11,389</u> | | <u>8,519</u> | |
| NOVA GAS TRANSMISSION LTD. | | | | | |
| Debtures and Notes | | | | | |
| Canadian dollars | 2010 to 2024 | 439 | 11.5% | 501 | 11.6% |
| U.S. dollars (2008 and 2007 – US\$375) | 2012 to 2023 | 457 | 8.2% | 368 | 8.2% |
| Medium-Term Notes | | | | | |
| Canadian dollars | 2025 to 2030 | 502 | 7.4% | 607 | 7.2% |
| U.S. dollars (2008 and 2007 – US\$33) | 2026 | 39 | 7.5% | 32 | 7.5% |
| | | <u>1,437</u> | | <u>1,508</u> | |
| TRANSCANADA PIPELINE USA LTD. | | | | | |
| Bank Loan | | | | | |
| U.S. dollars (2008 – US\$700; 2007 – US\$860) | 2012 | 857 | 2.4% | 850 | 5.7% |
| ANR PIPELINE COMPANY | | | | | |
| Senior Unsecured Notes | | | | | |
| U.S. dollars (2008 and 2007 – US\$444) | 2010 to 2025 | 541 | 9.1% | 435 | 9.1% |
| GAS TRANSMISSION NORTHWEST CORPORATION | | | | | |
| Senior Unsecured Notes | | | | | |
| U.S. Dollars (2008 and 2007 – US\$400) | 2010 to 2035 | 488 | 5.4% | 399 | 5.4% |
| TC PIPELINES, LP | | | | | |
| Unsecured Loan | | | | | |
| U.S. dollars (2008 – US\$475; 2007 – US\$507) | 2011 | 580 | 2.7% | 499 | 6.2% |
| GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP | | | | | |
| Senior Unsecured Notes | | | | | |
| U.S. dollars (2008 – US\$430; 2007 – US\$440) | 2011 to 2030 | 526 | 7.8% | 434 | 7.8% |
| TUSCARORA GAS TRANSMISSION COMPANY | | | | | |
| Senior Unsecured Notes | | | | | |
| U.S. dollars (2008 – US\$64; 2007 – US\$69) | 2010 to 2012 | 78 | 7.4% | 67 | 7.4% |
| PORTLAND NATURAL GAS TRANSMISSION SYSTEM | | | | | |
| Senior Secured Notes | | | | | |
| U.S. dollars (2008 – US\$196; 2007 – US\$211) ⁽⁵⁾ | 2018 | 236 | 6.1% | 205 | 6.1% |
| OTHER | | | | | |
| Senior Notes | | | | | |
| U.S. dollars (2008 – US\$18; 2007 – US\$17) | 2011 | 22 | 7.3% | 17 | 7.3% |
| | | <u>16,154</u> | | <u>12,933</u> | |
| Less: Current Portion of Long-Term Debt | | <u>786</u> | | <u>556</u> | |
| | | <u>15,368</u> | | <u>12,377</u> | |

- (1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.
- (2) Includes fair value adjustments for interest rate swap agreements on US\$50 million of debt at December 31, 2008 and 2007.
- (3) Includes fair value adjustments for interest rate swap agreements on \$50 million of debt at December 31, 2008 (2007 – \$150 million).
- (4) Includes fair value adjustments for interest rate swap agreements on US\$150 million of debt at December 31, 2008 and 2007.
- (5) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2009 – \$786 million; 2010 – \$531 million; 2011 – \$1,014 million; 2012 – \$1,370 million; and 2013 – \$1,180 million.

Debt Shelf Programs – TransCanada PipeLines Limited

In January 2009, the Company filed a debt shelf prospectus in the U.S. qualifying for issuance US\$3.0 billion of debt securities.

In March 2007, the Company filed debt shelf prospectuses in Canada and the U.S. qualifying for issuance \$1.5 billion of Medium-Term Notes and US\$1.5 billion of debt securities, respectively. Subsequent to the February 2009 debt issue discussed below, the Company had \$300 million of remaining capacity available under the Canadian shelf prospectus.

In September 2007, the Company replaced the March 2007 U.S. debt shelf prospectus with a US\$2.5 billion U.S. debt shelf prospectus. At December 31, 2008, the Company had fully utilized its capacity under the September 2007 U.S. shelf prospectus.

TransCanada PipeLines Limited

On February 17, 2009, TransCanada completed the issuance of Medium-Term Notes of \$300 million and \$400 million maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. These notes were issued under the \$1.5 billion debt shelf prospectus filed in Canada in March 2007.

On January 9, 2009, TransCanada issued US\$750 million and US\$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. These notes were issued under the January 2009 U.S. debt shelf prospectus.

In August 2008, TransCanada issued \$500 million of Medium-Term Notes maturing in August 2013, and bearing interest at 5.05 per cent under the March 2007 Canadian debt shelf prospectus.

In August 2008, TransCanada issued US\$850 million and US\$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. These notes were issued under the September 2007 U.S. debt shelf prospectus.

In October 2007, TransCanada issued US\$1.0 billion of Senior Unsecured Notes under the U.S. debt shelf filed in September 2007.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of \$225 million have retraction provisions that 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 were made to December 31, 2008.

TransCanada PipeLine USA Ltd.

In February 2007, TransCanada PipeLine USA Ltd. established a US\$1.0 billion committed, unsecured, syndicated credit facility, consisting of a US\$700-million five-year term loan and a US\$300-million five-year, extendible revolving facility. There was an outstanding balance of US\$700 million and US\$860 million on the credit facility at December 31, 2008 and 2007, respectively. In 2008, the maturity date of the revolving portion of the facility was extended to February 2013.

TC PipeLines, LP

In February 2007, PipeLines LP increased its syndicated revolving credit and term loan facility in connection with its acquisition of a 46.4 per cent interest in Great Lakes. The amount available under the facility increased to US\$950 million from US\$410 million and consisted of a US\$700-million senior term loan and a US\$250-million senior revolving credit facility, with US\$194 million of the senior term loan amount terminated upon closing of the Great Lakes acquisition. During 2008, an additional US\$13 million (2007 – US\$18 million) of the senior term loan was terminated due to principal repayments. There was an outstanding balance of US\$475 million and US\$507 million on the credit facility at December 31, 2008 and 2007, respectively.

Sensitivity

A one per cent change in interest rates would have the following effect assuming all other variables were to remain constant:

| <i>(millions of dollars)</i> | Increase | Decrease |
|---|----------|----------|
| Effect on fair value of fixed interest rate debt | (895) | 1,014 |
| Effect on interest expense of variable interest rate debt | 2 | (2) |

Financial Charges

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|------|------|
| Interest on long-term debt | 970 | 948 | 846 |
| Interest on junior subordinated notes | 68 | 43 | n/a |
| Interest on short-term debt | 32 | 48 | 23 |
| Capitalized interest | (141) | (68) | (60) |
| Amortization and other financial charges ⁽¹⁾ | 14 | (28) | 16 |
| | 943 | 943 | 825 |

⁽¹⁾ Amortization and other financial charges in 2008 and 2007 included amortization of transaction costs and debt discounts calculated using the effective interest method.

The Company made interest payments of \$833 million in 2008 (2007 – \$966 million; 2006 – \$771 million).

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

| <i>Outstanding loan amounts</i> <i>(millions of dollars)</i> | Maturity Dates | 2008 | | 2007 | |
|---|----------------|---|---------------------------------|---|---------------------------------|
| | | Outstanding December 31 ⁽¹⁾ | Interest Rate ⁽²⁾ | Outstanding December 31 ⁽¹⁾ | Interest Rate ⁽²⁾ |
| NORTHERN BORDER PIPELINE COMPANY | | | | | |
| Senior Unsecured Notes (2008 – US\$225; 2007 – US\$232) | 2009 to 2021 | 275 | 7.7% | 229 | 7.7% |
| Bank Facility (2008 – US\$96; 2007 – US\$83) | 2012 | 116 | 3.4% | 82 | 5.3% |
| IROQUOIS GAS TRANSMISSION SYSTEM, L.P. | | | | | |
| Senior Unsecured Notes (2008 – US\$160; 2007 – US\$165) | 2010 to 2027 | 195 | 7.6% | 162 | 7.5% |
| Bank Loan (2007 – US\$7) | | – | | 7 | 7.4% |
| BRUCE POWER L.P. AND BRUCE POWER A L.P. | | | | | |
| Capital Lease Obligations | 2018 | 235 | 7.5% | 243 | 7.5% |
| Term Loan | 2031 | 95 | 7.1% | n/a | |
| TRANS QUÉBEC & MARITIMES PIPELINE INC. | | | | | |
| Bonds | 2009 to 2010 | 137 | 6.0% | 137 | 6.0% |
| Term Loan | 2011 | 18 | 1.9% | 28 | 4.6% |
| OTHER | 2009 to 2010 | 5 | 5.5% | 15 | 4.5% |
| | | 1,076 | | 903 | |
| Less: Current Portion of Long-Term Debt of Joint Ventures | | 207 | | 30 | |
| | | 869 | | 873 | |

(1) Amounts outstanding represent TransCanada's proportionate share.

(2) Interest rates are the effective interest rates except those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2008, the effective interest rate resulting from swap agreements was 4.1 per cent on the Northern Border bank facility (2007 – nil). At December 31, 2007, the effective interest rate resulting from swap agreements was 7.5 per cent on the Iroquois bank loan.

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 of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TQM's bonds are secured by a first interest in all TQM real and immovable property and rights, a floating charge on all residual property and assets, and a specific interest on bonds of TQM Finance Inc. and on rights under all licenses and permits relating to the TQM pipeline system and natural gas transportation agreements.

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 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2009 – \$194 million; 2010 – \$212 million; 2011 – \$30 million; 2012 – \$126 million; and 2013 – \$8 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2009 – \$13 million; 2010 – \$13 million; 2011 – \$15 million; 2012 – \$18 million; and 2013 – \$20 million.

In September 2008, Bruce A entered into a \$193 million unsecured term loan, maturing December 2031 and bearing interest at 7.12 per cent.

In April 2007, Northern Border established a US\$250-million five-year unsecured bank facility. A portion of the bank facility was drawn to refinance US\$150 million of the Senior Unsecured Notes that matured on May 1, 2007.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

| <i>(millions of dollars)</i> | Increase | Decrease |
|---|----------|----------|
| Effect on fair value of fixed interest rate debt | (39) | 44 |
| Effect on interest expense of variable interest rate debt | 1 | (1) |

Financial Charges of Joint Ventures

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|-----------|------|------|
| Interest on long-term debt | 45 | 50 | 67 |
| Interest on capital lease obligations | 18 | 18 | 19 |
| Short-term interest and other financial charges | 7 | 4 | 3 |
| Deferrals and amortization | 2 | 3 | 3 |
| | 72 | 75 | 92 |

The Company's proportionate share of the interest payments of joint ventures was \$50 million in 2008 (2007 – \$45 million; 2006 – \$73 million).

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was \$18 million in 2008 (2007 – \$18 million; 2006 – \$20 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

| <i>Outstanding loan amount (millions of dollars)</i> | Maturity Dates | 2008 | | 2007 | |
|--|----------------|----------------------------|-------------------------------|----------------------------|-------------------------------|
| | | Outstanding December 31 | Effective Interest Rate | Outstanding December 31 | Effective Interest Rate |
| TRANSCANADA PIPELINES LIMITED | | | | | |
| U.S. dollars (2008 and 2007 – US\$1,000) | 2017 | <u>1,213</u> | 6.5% | <u>975</u> | 6.5% |

In April 2007, TransCanada Pipelines Limited (TCPL) issued US\$1.0 billion of Junior Subordinated Notes, maturing in 2067 and bearing interest of 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate, reset quarterly to the three-month London Interbank Offered Rate (LIBOR) plus 221 basis points. The Company has the option to defer payment of interest for periods of up to ten years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. The Company would be prohibited from paying dividends during any deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017 at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes. The Junior Subordinated Notes were issued under the U.S. debt shelf prospectus filed in March 2007.

Sensitivity

A one per cent change in interest rates would have the following effects assuming all other variables were to remain constant:

| <i>(millions of dollars)</i> | Increase | Decrease |
|---|----------|----------|
| Effect on fair value of Junior Subordinated Notes | (45) | 49 |

NOTE 13 DEFERRED AMOUNTS

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|--|--------------|-------|
| Fair value of derivative contracts (Note 17) | 694 | 205 |
| Regulatory liabilities (Note 14) | 551 | 525 |
| Employee benefit plans (Note 21) | 219 | 196 |
| Asset retirement obligations (Note 20) | 114 | 88 |
| Other | 141 | 93 |
| | 1,719 | 1,107 |

NOTE 14 REGULATED BUSINESSES

TransCanada's regulated businesses include Canadian and U.S. natural gas pipelines. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers. They arise from certain costs and revenues generated in the current period or in prior periods that may be collected from or refunded to shippers if, through the rate-setting process, it is found that revenues were over- or under-collected. Regulatory assets and liabilities are only recognized when approved by the applicable regulatory authorities. In addition to GAAP financial reporting, TransCanada's regulated pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied 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 regulated pipelines are set typically through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises 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 subject to a cost-of-service model wherein forecasted costs, including a return on capital, equal the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Costs for which the regulator does not allow the difference between actual and forecast to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act (Canada)*. The Alberta System is regulated by the AUC primarily under the provisions of the *Gas Utilities Act (Alberta)* and the *Pipeline Act (Alberta)*. The AUC regulates the construction and operation of facilities, and the terms and conditions of services, including rates for the Alberta System. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's other Canadian regulated natural gas transmission systems. The Alberta System has filed an application with the NEB to change its regulatory jurisdiction from the AUC to the NEB. The NEB's decision is expected in first quarter 2009.

Canadian Mainline

The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007, to December 31, 2011. Canadian Mainline's cost of capital for establishing tolls under the settlement reflects a rate of return on common equity (ROE) as determined by the NEB's ROE formula, on a deemed common equity ratio of 40 per cent. The allowed ROE in 2008 for Canadian Mainline was 8.71 per cent (2007 – 8.46 per cent). The remaining capital structure consists of short- and long-term debt following the agreed-upon redemption of US\$460 million of Preferred Securities in 2007.

The settlement also establishes the Canadian Mainline's fixed operations, maintenance and administrative (OM&A) costs for each year of the five years. Any variance between actual OM&A costs and those agreed to in the settlement accrue to TransCanada from 2007 to 2009. Variances in OM&A costs will be shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. There are also performance-based incentive arrangements that provide mutual benefits to both TransCanada and its customers.

Alberta System

In March 2008, NOVA Gas Transmission Ltd. (NGTL) reached a revenue requirement settlement with interested stakeholders for 2008 and 2009 on the Alberta System. In December 2008, the AUC approved the 2008-2009 Revenue Requirement Settlement Application, which is effective for the full two-year period.

As part of the settlement, fixed costs were established for certain operating costs, ROE and income taxes. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada, subject to ROE and income tax adjustment mechanisms. All other costs of the revenue requirement are treated on a flow-through basis.

Other Canadian Pipelines

The NEB approves pipeline tolls on an annual cost of service basis for Foothills 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 the 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 calculated and reflected in the subsequent year's tolls.

The ROE for Foothills, which is based on the NEB-allowed ROE formula, was 8.71 per cent in 2008 (2007 – 8.46 per cent) on a deemed equity component of 36 per cent.

In September 2008, the NEB approved TQM's application for a three-year partial negotiated settlement with interested parties concerning all cost of service matters, with the exception of cost of capital and associated income taxes, for the years 2007 to 2009. In December 2007, TQM filed a cost of capital application with the NEB for the years 2007 and 2008, which requests approval of an 11 per cent return on deemed common equity of 40 per cent. An NEB hearing on the application concluded in October 2008 and a decision from the NEB is expected in early 2009. TQM currently is subject to the NEB ROE formula on deemed common equity of 30 per cent. TQM tolls remain in effect on an interim basis pending a decision on the application. Any adjustments to the interim tolls will be recorded in accordance with the decision.

U.S. Regulated Operations

TransCanada's wholly owned and partially owned U.S. pipelines are 'natural gas companies' operating under the provisions of the *Natural Gas Act of 1938*, the *Natural Gas Policy Act of 1978* and the *Energy Policy Act of 2005*, 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.

ANR

ANR's operations are regulated primarily by the FERC. ANR's natural gas storage and transportation services regulated by the FERC also operate under approved tariff rates. ANR Pipeline's rates were established pursuant to a settlement approved by a FERC order issued in February 1998 and became effective in November 1997. These tariffs include maximum and minimum rate levels for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC in April 1990 and became effective in June 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

GTN

GTN is regulated by the FERC. Both of GTN's natural gas pipeline systems, the GTN System and North Baja, operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. The pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. The GTN System and its customers reached a rate case settlement in November 2007 that was approved by the FERC in January 2008. GTN's financial results in 2007 reflected the terms of the settlement. In 2008, the GTN System refunded to customers amounts collected above the settlement rates for the period from January 1, 2007 through October 31, 2007. Under the settlement, a five-year moratorium was established during which the GTN System and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any filings. The GTN System is also required to file a rate case within seven years. Rates for capacity on North Baja were established in 2002 in the FERC's initial order certifying construction and operations of North Baja.

Great Lakes

Great Lakes' rates and tariffs are regulated by the FERC. In 2000, Great Lakes negotiated an overall rate settlement with its customers that established the rates currently in effect. The settlement expired October 31, 2005, with no requirement to file for new rates at any time, nor is Great Lakes prohibited from filing such a rate case. Great Lakes' services are provided pursuant to its FERC-approved tariff, which includes, among other factors, maximum and minimum rate levels for services and permits Great Lakes to negotiate or discount rates on a non-discriminatory basis.

Portland

In April 2008, Portland filed a general rate case under the *Natural Gas Act of 1938*, in accordance with the terms of its previous settlement approved by the FERC in 2003. The proposed tariffs, which included a rate increase of approximately six per cent, became effective September 1, 2008, subject to refund, in accordance with a FERC order dated May 1, 2008. The rate case hearing is scheduled to begin in July 2009.

Northern Border

Northern Border and its customers reached a settlement in September 2006 that was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. The settlement provided for seasonal rates, which vary on a monthly basis, for short-term transportation services. It also included a three-year moratorium on filing rate cases and on participants filing challenges to rates, and required that Northern Border file a general rate case within six years. Northern Border is required to provide services under negotiated and discounted rates on a non-discriminatory basis.

Regulatory Assets and Liabilities

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | Remaining Recovery/ Settlement Period (years) |
|---|-------------|------|---|
| Regulatory Assets | | | |
| Unrealized losses on derivatives ⁽¹⁾ | 67 | 106 | 1 - 5 |
| Foreign exchange on long-term debt principal ⁽²⁾ | 32 | 34 | 21 |
| Deferred income tax on carrying costs capitalized during construction of utility plant ⁽³⁾ | 26 | 20 | n/a |
| Unamortized issue costs on Preferred Securities ⁽⁴⁾ | 18 | 19 | 18 |
| Phase II preliminary expenditures ⁽⁵⁾ | 16 | 18 | 7 |
| Transitional other benefit obligations ⁽⁶⁾ | 15 | 16 | 8 |
| Unamortized post-retirement benefits ⁽⁷⁾ | 11 | 13 | 3 - 5 |
| Operating and debt-service regulatory assets ⁽⁸⁾ | – | 85 | n/a |
| Other | 16 | 25 | n/a |
| Total Regulatory Assets (Other Assets) | 201 | 336 | |
| Regulatory Liabilities | | | |
| Operating and debt-service regulatory liabilities ⁽⁸⁾ | 234 | 3 | 1 |
| Foreign exchange gain on redemption of Preferred Securities, net of income tax of \$10 million (2007 – \$15 million) ⁽⁴⁾ | 101 | 150 | 3 |
| Foreign exchange on long-term debt ⁽⁹⁾ | 70 | 266 | 4 - 21 |
| Post-retirement benefits other than pension ⁽¹⁰⁾ | 58 | 38 | n/a |
| Unamortized gains on derivatives ⁽¹⁾ | 24 | n/a | 4 |
| Fuel tracker ⁽¹¹⁾ | 23 | 29 | n/a |
| Negative salvage ⁽¹²⁾ | 16 | 17 | n/a |
| Other | 25 | 22 | n/a |
| Total Regulatory Liabilities (Deferred Amounts) | 551 | 525 | |

⁽¹⁾ Unrealized gains and losses on derivatives represent the net position of fair value gains and losses on cross-currency and interest-rate swaps, and forward foreign currency contracts, which act as economic hedges. The cross-currency swaps pertain to foreign debt instruments associated with the Canadian Mainline, Foothills and Alberta System. Pre-tax operating results would have been \$63 million higher in 2008 (2007 – \$22 million lower) if these amounts had not been recorded as regulatory assets and liabilities.

⁽²⁾ The foreign exchange on long-term debt principal account in the Alberta System, as approved by the AUC, is designed to facilitate the recovery or refund of foreign exchange gains and losses over the life of the foreign currency debt issues. Realized gains and losses and estimated net future losses on foreign currency debt are 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. Pre-tax operating results would have been \$2 million lower in 2008 (2007 – \$1 million higher) if these amounts had not been recorded as regulatory assets.

⁽³⁾ Rate-regulated accounting allows the capitalization of both equity and interest components for the carrying costs of funds used during the construction of utility assets. The capitalized AFUDC is depreciated as part of the total depreciable plant after the utility assets are placed in service. Equity AFUDC is not subject to income taxes, therefore, a deferred tax provision is recorded with an offset to a corresponding regulatory asset.

⁽⁴⁾ In July 2007, the Company redeemed the US\$460-million 8.25 per cent Preferred Securities that underpinned the Canadian Mainline's investment base. Upon redemption of the securities, there was a realized foreign exchange gain that will flow through, net of income tax, to Canadian Mainline's customers over the five years of the current rate case settlement. In addition, the issue costs on the Preferred Securities will be amortized over 20 years beginning January 1, 2007. GAAP would have required the foreign exchange gain and the unamortized issue costs to be included in the operating results of the Canadian Mainline in the year the securities were redeemed if these amounts had not been recorded as regulatory assets. This would have (decreased)/increased 2008 pre-tax operating results by \$(54) million and \$1 million (2007 – \$165 million and \$(19) million) related to the foreign exchange gain and issue costs, respectively.

⁽⁵⁾ Phase II preliminary expenditures are costs incurred by Foothills prior to 1981 related to development of Canadian facilities to deliver Alaskan gas. These costs have been approved by the regulator for collection through straight-line amortization over the period November 2002 to December 2015. Pre-tax operating results would have been \$2 million higher in 2008 (2007 – \$2 million higher) if these amounts had not been recorded as regulatory assets.

- (6) The regulatory asset with respect to the annual transitional other benefit obligations is being amortized over 17 years to December 2016, at which time the full transitional obligation will have been recovered through tolls. Pre-tax operating results would have been \$1 million higher in 2008 (2007 – \$2 million higher) if these amounts had not been recorded as regulatory assets.
- (7) An amount is recovered in ANR's rates for post-retirement benefits other than pensions (PBOP). A curtailment and special termination benefits charge related to PBOP for a closed group of retirees was recorded as a regulatory asset and is being amortized through 2011. Pre-tax operating results would have been \$3 million higher in 2008 (2007 – \$3 million higher) if these amounts had not been recorded as regulatory assets.
- (8) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the immediate following calendar year. Pre-tax operating results would have been \$316 million higher in 2008 (2007 – \$152 million lower) if these amounts had not been recorded as regulatory assets and liabilities.
- (9) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historic foreign exchange rate. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of rate-regulated 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.
- (10) An amount is recovered in ANR's rates for PBOP. This regulatory liability represents the difference between the amount collected in rates and the amount of PBOP expense. No PBOP expense was recorded in 2008 and 2007.
- (11) ANR's tariff stipulates a fuel tracker mechanism to track over- or under-collections of fuel used and gas lost and unaccounted for (collectively, fuel). The fuel tracker represents the difference between the value of 'in-kind' natural gas retained from shippers and the actual amount of natural gas used for fuel by ANR. Any over- or under-collections are returned to or collected from shippers through a prospective annual adjustment to fuel retention rates. A regulatory asset or liability is established for the difference between ANR's actual fuel use and amounts collected through its fuel rates. Pre-tax operating results are not affected by the fuel tracker mechanism.
- (12) ANR collects in its current rates an allowance for negative salvage related to its offshore transmission and gathering facilities. The allowance for negative salvage is collected as a component of depreciation expense and recorded to a negative salvage account within the reserve for accumulated depreciation. Costs associated with the abandonment of offshore transmission and with gathering facilities are recorded against the negative salvage reserve.

As prescribed by regulators, the taxes payable method of accounting for income taxes is used for toll-making purposes on Canadian regulated natural gas transmission operations. As permitted by GAAP at December 31, 2008, this method is also used for accounting purposes. Consequently, future income tax liabilities have not been recognized, as it is expected they will be recovered through future rates when the amounts become payable. In the absence of rate-regulated accounting, GAAP would have required the recognition of future income tax liabilities. If the liability method of accounting had been used, additional future income tax liabilities would have been recorded at December 31, 2008 and would have been recoverable from future revenues. The liability method of accounting is used for both accounting and toll-making purposes for the U.S. natural gas transmission operations. Under this method, future income tax assets and liabilities are recognized based on the differences between financial statement carrying amounts and the tax basis of the assets and liabilities. This method is also used for toll-making purposes for the U.S. natural gas transmission operations. As a result, current year's revenues include a tax provision that is calculated based on the liability method of accounting and there is no recognition of a related regulatory asset or liability. Effective January 1, 2009, the Company will be adopting policies consistent with FAS 71 to account for its rate-regulated pipelines, as discussed in Note 3.

NOTE 15 NON-CONTROLLING INTERESTS

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

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|--|--------------|------|
| Non-controlling interest in PipeLines LP | 721 | 539 |
| Preferred shares of subsidiary | 389 | 389 |
| Non-controlling interest in Portland | 84 | 71 |
| | 1,194 | 999 |

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

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|-------------|------|------|
| Non-controlling interest in PipeLines LP | 62 | 65 | 43 |
| Preferred share dividends of subsidiary | 22 | 22 | 22 |
| Non-controlling interest in Portland | 46 | 10 | 13 |
| | 130 | 97 | 78 |

The non-controlling interests in PipeLines LP and Portland as at December 31, 2008 represented the 67.9 per cent and 38.3 per cent interest, respectively, not owned by TransCanada (2007 – 67.9 per cent and 38.3 per cent, respectively).

TransCanada received revenues of \$2 million from PipeLines LP in 2008 (2007 – \$2 million; 2006 – \$1 million) and \$7 million from Portland in 2008 (2007 – \$7 million; 2006 – \$6 million) for services it provided.

Preferred Shares of Subsidiary

| <i>December 31</i> | Number of Shares | Dividend Rate Per Share | Redemption Price Per Share | 2008 | 2007 |
|--|---------------------|----------------------------|-------------------------------|-----------------------|-----------------------|
| | (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 TCPL are without par value.

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

NOTE 16 COMMON SHARES

| | Number of Shares | Amount |
|---|------------------|-----------------------|
| | (thousands) | (millions of dollars) |
| Outstanding at January 1, 2006 | 487,236 | 4,755 |
| Exercise of options | 1,739 | 39 |
| Outstanding at December 31, 2006 | 488,975 | 4,794 |
| Issuance of common shares ⁽¹⁾ | 45,390 | 1,683 |
| Dividend reinvestment and share purchase plan | 4,147 | 157 |
| Exercise of options | 1,253 | 28 |
| Outstanding at December 31, 2007 | 539,765 | 6,662 |
| Issuance of common shares ⁽¹⁾ | 69,805 | 2,363 |
| Dividend reinvestment and share purchase plan | 5,976 | 218 |
| Exercise of options | 925 | 21 |
| Outstanding at December 31, 2008 | 616,471 | 9,264 |

⁽¹⁾ Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In July 2008, TransCanada filed a final short form base shelf prospectus in Canada and the U.S. to allow for the offering of up to \$3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until August 2010. This shelf prospectus replaced the previous base shelf prospectus filed in January 2007. The Company issued the following equity under the July 2008 prospectus:

- In fourth quarter 2008, TransCanada completed a public offering of common shares at a purchase price of \$33.00 per share. The entire issue of 35.1 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of \$1.2 billion.

In January 2007, TransCanada filed a short form base shelf prospectus in Canada and the U.S. to allow for the offering of up to \$3.0 billion of common shares, preferred shares and/or subscription receipts in Canada and the U.S. until February 2009. The Company issued the following equity under the January 2007 prospectus:

- In first quarter 2007, the Company completed a public offering of common shares at a purchase price of \$38.00 per share. The entire issue of 45.4 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of \$1.7 billion.
- In May 2008, TransCanada completed a public offering of common shares at a purchase price of \$36.50 per share. The entire issue of 34.7 million common shares, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of \$1.3 billion.

Net Income per Share

During the year, the weighted average number of common shares of 569.6 million and 571.5 million (2007 – 529.9 million and 532.5 million; 2006 – 488.0 million and 490.6 million) were used to calculate basic and diluted earnings per share, 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 (thousands) | Weighted Average Exercise Prices | Options Exercisable (thousands) |
|---|-------------------------------------|--|---------------------------------------|
| Outstanding January 1, 2006 | 8,714 | \$22.67 | 6,300 |
| Granted | 1,841 | \$34.48 | |
| Exercised | (1,739) | \$21.44 | |
| Forfeited | (17) | \$30.98 | |
| Outstanding at December 31, 2006 | 8,799 | \$25.37 | 5,888 |
| Granted | 1,083 | \$38.10 | |
| Exercised | (1,253) | \$22.77 | |
| Forfeited | (20) | \$35.08 | |
| Outstanding at December 31, 2007 | 8,609 | \$27.32 | 6,118 |
| Granted | 872 | \$39.75 | |
| Exercised | (925) | \$22.26 | |
| Forfeited | (55) | \$35.23 | |
| Outstanding at December 31, 2008 | 8,501 | \$29.10 | 6,461 |

Stock options outstanding at December 31, 2008, were as follows:

| Range of Exercise Prices | Options Outstanding | | | Options Exercisable | | |
|--------------------------|-------------------------------------|--|--|-------------------------------------|--|---|
| | Number of Options (thousands) | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (years) | Number of Options (thousands) | Weighted Average Exercise Price | Weighted Average Remaining Life (years) |
| \$10.03 to \$20.58 | 1,242 | \$17.22 | 1.9 | 1,242 | \$17.22 | 1.9 |
| \$20.59 to \$21.86 | 927 | \$21.42 | 3.1 | 927 | \$21.42 | 3.1 |
| \$22.33 to \$24.49 | 766 | \$22.33 | 1.2 | 766 | \$22.33 | 1.2 |
| \$24.61 to \$26.85 | 971 | \$26.84 | 2.1 | 971 | \$26.84 | 2.1 |
| \$30.09 to \$33.08 | 1,527 | \$31.33 | 3.8 | 1,314 | \$31.04 | 3.7 |
| \$35.23 | 1,106 | \$35.23 | 4.2 | 854 | \$35.23 | 4.2 |
| \$36.67 to \$38.10 | 983 | \$38.07 | 5.1 | 341 | \$38.02 | 5.1 |
| \$38.14 to \$39.75 | 979 | \$39.57 | 6.1 | 46 | \$38.29 | 5.3 |
| | 8,501 | \$29.10 | 3.4 | 6,461 | \$26.31 | 3.3 |

An additional 4.0 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2008. In 2008, TransCanada issued 871,733 options to purchase common shares at an average price of \$39.75 under the Company's Stock Option Plan and the weighted average fair value of each option was determined to be \$3.27 (2007 – \$4.22; 2006 – \$3.53). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2008: four years of expected life (2007 and 2006 – four years); 1.5 per cent interest rate (2007 and 2006 – 4.1 per cent); 28 per cent volatility (2007 – 15 per cent; 2006 – 14 per cent); and 4.5 per cent dividend yield (2007 – 3.6 per cent; 2006 – 3.7 per cent). The amount expensed for stock options, with a corresponding increase in contributed surplus, was \$4 million in 2008 (2007 – \$4 million; 2006 – \$3 million).

The total intrinsic value of options exercised in 2008 was \$15 million. As at December 31, 2008, the aggregate intrinsic value was \$48 million for each of the total currently exercisable options and the total outstanding options. In 2008, the 1.4 million shares that vested had a fair value of \$45 million.

Shareholder Rights Plan

TransCanada'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 that entitles certain holders to purchase two common shares of the Company for the price of one.

Dividend Reinvestment and Share Purchase Plan

Commencing in 2007, TransCanada's Board of Directors authorized the issuance of common shares from treasury at a discount to participants in the Company's Dividend Reinvestment and Share Purchase Plan (DRP). Under the DRP, eligible shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. The discount was set at two per cent commencing with the dividend payable in April 2007 and was increased to three per cent for the dividend payable in January 2009. The Company reserves the right to alter the discount or return to purchasing shares on the open market at any time. In accordance with the DRP, dividends of \$218 million were paid in 2008 by the issuance from treasury of 6.0 million common shares. In 2007, dividends of \$157 million were paid by the issuance from treasury of 4.1 million common shares. Prior to the April 2007 dividend, TransCanada purchased shares on the open market and provided them to DRP participants at cost.

NOTE 17 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk, and liquidity risk. TransCanada engages in risk management activities with the primary objective being to protect earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee. The Board of Directors also has a Governance Committee that assists in overseeing the risk management activities of TransCanada. The Governance Committee monitors, reviews with management and makes recommendations related to TransCanada's risk management programs and policies on an ongoing basis.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management policy to manage exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to the Company's overall risk management policies, the Company commits a significant portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sales price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfill the Company's power sales commitments is purchased with contracts or fulfilled through power generation, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions and derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but are not within the scope of CICA Handbook Section 3855 "Financial Instruments – Recognition and Measurement", as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements exemption. Certain other contracts are not within the scope of Section 3855 as they are considered to meet other exemptions.

TransCanada manages its exposure to seasonal natural gas price spreads in its natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded each period on proprietary natural gas storage inventory and these forward contracts may not be representative of the amounts that will be realized on settlement.

Natural Gas Inventory Price Risk

At December 31, 2008, \$76 million (2007 – \$190 million) of proprietary natural gas inventory was included in Inventories. Effective April 2007, TransCanada began valuing its proprietary natural gas inventory held in storage at fair value, as measured by the one-month forward price for natural gas less selling costs. The Company did not have any proprietary natural gas inventory held in storage prior to April 2007. In 2008, the net change in fair value of proprietary natural gas held in inventory was a net unrealized loss of \$7 million (2007 – nil), which was recorded as a decrease to Revenue and Inventory. In 2008, the net change in fair value of natural gas forward purchases and sales contracts was a net unrealized gain of \$7 million (2007 – \$10 million) which was included in Revenues.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and/or market interest rates.

A portion of TransCanada's earnings from its Pipelines and Energy operations is generated in U.S. dollars and is subject to currency fluctuations. The performance of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is offset by certain related debt and financing costs being denominated in U.S. dollars and by the Company's hedging activities. Due to its increased U.S. operations, TransCanada has a greater exposure to U.S. currency fluctuations than in prior years.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposure of the Canadian Mainline, Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are shared with shippers on predetermined terms. These gains and losses are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt, which subjects it to interest rate cash flow risk. The Company uses a combination of forwards, interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, forward foreign exchange contracts, cross-currency interest rate swaps and foreign exchange options. At December 31, 2008, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$7.2 billion (US\$5.9 billion) (2007 – \$4.7 billion (US\$4.7 billion)) and a fair value of \$5.9 billion (US\$4.8 billion) (2007 – \$4.8 billion (US\$4.8 billion)). In January 2009, the Company issued an additional US\$2.0 billion of long-term debt and designated it as a hedge of the net U.S. dollar investment in foreign operations. At December 31, 2008, \$254 million was included in Deferred Amounts for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amount for the derivatives designated as a net investment hedge were as follows:

| Asset/(Liability) | 2008 | | 2007 | |
|---|------------|------------------------------|------------|------------------------------|
| | Fair Value | Notional or Principal Amount | Fair Value | Notional or Principal Amount |
| <i>December 31 (millions of dollars)</i> | | | | |
| U.S. dollar cross-currency swaps (maturing 2009 to 2014) | (218) | U.S. 1,650 | 77 | U.S. 350 |
| U.S. dollar forward foreign exchange contracts (maturing 2009) | (42) | U.S. 2,152 | (4) | U.S. 150 |
| U.S. dollar options (maturing 2009) | 6 | U.S. 300 | 3 | U.S. 600 |
| | (254) | U.S. 4,102 | 76 | U.S. 1,100 |

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact resulting from its exposure to market risk. VaR estimates the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number calculated and used by TransCanada reflects the 95 per cent probability that the daily change resulting from normal market fluctuations in its liquid positions will not exceed the reported VaR. The VaR methodology is a statistically-calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the Pipelines segment as the rate-regulated nature of the pipeline business reduces the impact of market risks. The Company's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was \$23 million at December 31, 2008 (2007 – \$8 million). The increase from December 31, 2007 was primarily due to the Ravenswood acquisition.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that these processes will protect it against all losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date consisted primarily of the carrying amount, which approximates fair value, of non-derivative financial assets, such as accounts receivable, as well as the fair value of derivative financial assets.

The Company does not have significant concentrations of counterparty credit risk with any individual counterparties and the majority of counterparty credit exposure is with counterparties who are investment grade. At December 31, 2008, there were no significant amounts past due or impaired.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-credit worthy counterparties.

During the deterioration of global financial markets in 2008, TransCanada continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it is deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market risk and counterparty credit risk when making business decisions.

Certain subsidiaries of Calpine Corporation (Calpine) filed for bankruptcy protection in both Canada and the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland Natural Gas Transmission System (PNGTS) reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and PNGTS received initial distributions of 9.4 million common shares and 6.1 million common shares of Calpine, respectively, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were subsequently sold into the open market and resulted in total pre-tax gains of \$279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for \$32 million and \$44 million, respectively, were received in cash in January 2008 and will be passed on to shippers on these systems. At December 31, 2008, \$22 million remained in regulatory liabilities for these claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure that, under both normal and stressed conditions, it always has sufficient cash and credit facilities to meet its obligations when due, without incurring unacceptable losses or damage to the Company's reputation.

Management forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed under the heading Capital Management in this note.

At December 31, 2008, the Company had committed revolving bank lines of US\$1.0 billion, \$2.0 billion and US\$300 million maturing in November 2010, December 2012 and February 2013, respectively. As of December 31, 2008, no draws were made on these facilities as the Company has continued to have largely uninterrupted access to the Canadian commercial paper market on competitive terms. In January 2009, TransCanada filed a new US\$3.0 billion debt shelf in the U.S. to supplement the \$1.8 billion and \$1.0 billion of capacity available under its existing equity and Canadian debt shelves, respectively. The Company has US\$1.0 billion of capacity remaining available under its January 2009 U.S. debt shelf.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2008:

Contractual Repayments of Financial Liabilities⁽¹⁾

| <i>(millions of dollars)</i> | Total | Payments Due by Period | | | |
|--|---------------|------------------------|------------------|------------------|------------------------|
| | | 2009 | 2010 and 2011 | 2012 and 2013 | 2014 and Thereafter |
| Notes payable | 1,702 | 1,702 | – | – | – |
| Long-term debt and junior subordinated notes | 17,367 | 786 | 1,545 | 2,550 | 12,486 |
| Long-term debt of joint ventures | 1,076 | 207 | 270 | 172 | 427 |
| Total contractual repayments | 20,145 | 2,695 | 1,815 | 2,722 | 12,913 |

⁽¹⁾ The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this Note.

Interest Payments on Financial Liabilities

| <i>(millions of dollars)</i> | Total | Payments Due by Period | | | |
|--|---------------|------------------------|------------------|------------------|------------------------|
| | | 2009 | 2010 and 2011 | 2012 and 2013 | 2014 and Thereafter |
| Long-term debt and junior subordinated notes | 15,170 | 1,150 | 2,151 | 1,950 | 9,919 |
| Long-term debt of joint ventures | 328 | 61 | 76 | 56 | 135 |
| Total interest payments | 15,498 | 1,211 | 2,227 | 2,006 | 10,054 |

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2008, this overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt is comprised of Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The capital structure at December 31 was as follows:

| <i>(millions of dollars)</i> | 2008 | 2007 |
|------------------------------|----------------|--------|
| Notes payable | 1,685 | 407 |
| Long-term debt | 16,154 | 12,933 |
| Junior subordinated notes | 1,213 | 975 |
| Cash and cash equivalents | (1,117) | (333) |
| Net debt | 17,935 | 13,982 |
| Non-controlling interests | 1,194 | 999 |
| Shareholders' equity | 12,898 | 9,785 |
| Total equity | 14,092 | 10,784 |
| Total capital | 32,027 | 24,766 |

Fair Values

The fair value of financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts approximates their carrying amounts due to the nature of the item and/or the short time to maturity. 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 oil products derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes are used. Credit risk has been taken into consideration when calculating fair values.

Valuation techniques that refer to observable market data or estimated market prices may also be used to calculate fair value. These include comparisons with similar instruments that have observable market prices, option pricing models and other valuation techniques commonly used by market participants. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Company looks primarily to readily observable external market input factors such as interest rate yield curves, currency rates and price and rate volatilities, as applicable.

The fair value of the Company's Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments and, when such information was not available, was estimated by discounting future payments of interest and principal at estimated interest rates that were made available to the Company.

Fair Value of Long-Term Debt and Other Long-Term Securities

The carrying and fair values of long-term debt and other long-term securities were as follows:

| <i>December 31 (millions of dollars)</i> | 2008 | | 2007 | |
|--|-----------------|---------------|-----------------|------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-Term Debt | | | | |
| TransCanada PipeLines Limited ⁽¹⁾ | 11,389 | 10,583 | 8,519 | 9,400 |
| NOVA Gas Transmission Ltd. | 1,437 | 1,534 | 1,508 | 1,877 |
| TransCanada PipeLine USA Ltd. | 857 | 857 | 850 | 850 |
| ANR Pipeline Company | 541 | 570 | 435 | 573 |
| Gas Transmission Northwest Corporation | 488 | 393 | 399 | 383 |
| TC PipeLines, LP | 580 | 580 | 499 | 499 |
| Great Lakes Gas Transmission Limited Partnership | 526 | 496 | 434 | 519 |
| Tuscarora Gas Transmission Company | 78 | 80 | 67 | 81 |
| Portland Natural Gas Transmission System | 236 | 220 | 205 | 214 |
| Other | 22 | 24 | 17 | 24 |
| | 16,154 | 15,337 | 12,933 | 14,420 |
| Junior Subordinated Notes | 1,213 | 815 | 975 | 914 |
| | 17,367 | 16,152 | 13,908 | 15,334 |
| Long-Term Debt of Joint Ventures | | | | |
| Northern Border Pipeline Company | 391 | 391 | 311 | 329 |
| Iroquois Gas Transmission System, L.P. | 195 | 181 | 169 | 180 |
| Bruce Power L.P. and Bruce Power A L.P. | 330 | 318 | 243 | 243 |
| Trans Québec & Maritimes Pipeline Inc. | 155 | 157 | 165 | 169 |
| Other | 5 | 5 | 15 | 16 |
| | 1,076 | 1,052 | 903 | 937 |
| | 18,443 | 17,204 | 14,811 | 16,271 |

⁽¹⁾ At December 31, 2008, the carrying amount of Long-Term Debt included \$15 million (2007 – \$15 million) for fair value adjustments related to swap agreements on \$50 million (2007 – \$150 million) and US\$200 million (2007 – US\$200 million) of this debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

| <i>December 31 (millions of dollars)</i> | 2008 | | 2007 | |
|--|-----------------|---------------|-----------------|------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Financial Assets⁽¹⁾ | | | | |
| Cash and cash equivalents | 1,308 | 1,308 | 504 | 504 |
| Accounts receivable and other assets ⁽²⁾⁽³⁾ | 1,404 | 1,404 | 1,231 | 1,231 |
| Available-for-sale assets ⁽²⁾ | 27 | 27 | 17 | 17 |
| | 2,739 | 2,739 | 1,752 | 1,752 |
| Financial Liabilities⁽¹⁾⁽³⁾ | | | | |
| Notes payable | 1,702 | 1,702 | 421 | 421 |
| Accounts payable and deferred amounts ⁽⁴⁾ | 1,372 | 1,372 | 1,193 | 1,193 |
| Accrued interest | 359 | 359 | 261 | 261 |
| Long-term debt and junior subordinated notes | 17,367 | 16,152 | 13,908 | 15,334 |
| Long-term debt of joint ventures | 1,076 | 1,052 | 903 | 937 |
| Other long-term liabilities of joint ventures ⁽⁴⁾ | – | – | 60 | 60 |
| | 21,876 | 20,637 | 16,746 | 18,206 |

⁽¹⁾ Consolidated Net Income in 2008 and 2007 included unrealized gains or losses of nil for the fair value adjustments to each of these financial instruments.

⁽²⁾ At December 31, 2008, the Consolidated Balance Sheet included financial assets of \$1,257 million (2007 – \$1,018 million) in Accounts Receivable and \$174 million (2007 – \$230 million) in Other Assets.

⁽³⁾ Recorded at amortized cost, except for certain Long-Term Debt which is adjusted to fair value.

⁽⁴⁾ At December 31, 2008, the Consolidated Balance Sheet included financial liabilities of \$1,350 million (2007 – \$1,175 million) in Accounts Payable and \$22 million (2007 – \$78 million) in Deferred Amounts.

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

| December 31 (all amounts in millions unless otherwise indicated) | 2008 | | | | |
|---|-----------|-------------|--------------|------------------|------------|
| | Power | Natural Gas | Oil Products | Foreign Exchange | Interest |
| Derivative Financial Instruments Held for Trading | | | | | |
| Fair Values ⁽¹⁾ | | | | | |
| Assets | \$132 | \$144 | \$10 | \$41 | \$57 |
| Liabilities | \$(82) | \$(150) | \$(10) | \$(55) | \$(117) |
| Notional Values | | | | | |
| Volumes ⁽²⁾ | | | | | |
| Purchases | 4,035 | 172 | 410 | – | – |
| Sales | 5,491 | 162 | 252 | – | – |
| Canadian dollars | – | – | – | – | 1,016 |
| U.S. dollars | – | – | – | U.S. 479 | U.S. 1,575 |
| Japanese yen (in billions) | – | – | – | JPY 4.3 | – |
| Cross-currency | – | – | – | 227/U.S. 157 | – |
| Net unrealized gains/(losses) in the year ⁽³⁾ | \$24 | \$(23) | \$1 | \$(9) | \$(61) |
| Net realized gains/(losses) in the year ⁽³⁾ | \$23 | \$(2) | \$1 | \$6 | \$13 |
| Maturity dates | 2009-2014 | 2009-2011 | 2009 | 2009-2012 | 2009-2018 |
| Derivative Financial Instruments in Hedging Relationships⁽⁴⁾⁽⁵⁾ | | | | | |
| Fair Values ⁽¹⁾ | | | | | |
| Assets | \$115 | \$– | \$– | \$2 | \$8 |
| Liabilities | \$(160) | \$(18) | \$– | \$(24) | \$(122) |
| Notional Values | | | | | |
| Volumes ⁽²⁾ | | | | | |
| Purchases | 8,926 | 9 | – | – | – |
| Sales | 13,113 | – | – | – | – |
| Canadian dollars | – | – | – | – | 50 |
| U.S. dollars | – | – | – | U.S. 15 | U.S. 1,475 |
| Cross-currency | – | – | – | 136/U.S. 100 | – |
| Net realized (losses)/gains in the year ⁽³⁾ | \$(56) | \$15 | \$– | \$– | \$(10) |
| Maturity dates | 2009-2014 | 2009-2011 | – | 2009-2013 | 2009-2019 |

(1) Fair value is equal to the carrying value of these derivatives.

(2) Volumes for power, natural gas and oil products derivatives are in gigawatt hours, billion cubic feet and thousands of barrels, respectively.

(3) All power, natural gas and oil products realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

(4) All hedging relationships are designated as cash flow hedges except for interest-rate derivative financial instruments designated as fair value hedges with a fair value of \$8 million. In 2008, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2008, Net Income included losses of \$6 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2008, there were no gains or losses included in Net Income for discontinued cash flow hedges.

The anticipated timing of settlement of the derivative contracts assumes no changes in commodity prices, interest rates and foreign exchange rates from December 31, 2008. Actual settlements will vary based on changes in these factors. The anticipated timing of settlement of these contracts is as follows:

| (millions of dollars) | Total | 2009 | 2010 and 2011 | 2012 and 2013 | 2014 and Thereafter |
|---|-------|------|---------------|---------------|---------------------|
| Derivative financial instruments held for trading | (30) | 38 | (46) | (14) | (8) |
| Derivative financial instruments in hedging relationships | (199) | (68) | (65) | (43) | (23) |
| | (229) | (30) | (111) | (57) | (31) |

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments is as follows:

| December 31 (all amounts in millions unless otherwise indicated) | 2007 | | | |
|---|-----------|-------------|------------------|-----------|
| | Power | Natural Gas | Foreign Exchange | Interest |
| Derivative Financial Instruments Held for Trading | | | | |
| Fair Values ⁽¹⁾ | | | | |
| Assets | \$55 | \$43 | \$11 | \$23 |
| Liabilities | \$(44) | \$(19) | \$(79) | \$(18) |
| Notional Values | | | | |
| Volumes ⁽²⁾ | | | | |
| Purchases | 3,774 | 47 | — | — |
| Sales | 4,469 | 64 | — | — |
| Canadian dollars | — | — | — | 615 |
| U.S. dollars | — | — | U.S. 484 | U.S. 550 |
| Japanese yen (in billions) | — | — | JPY 9.7 | — |
| Cross-currency | — | — | 227/U.S. 157 | — |
| Net unrealized gains/(losses) in the year ⁽³⁾ | \$16 | \$(10) | \$8 | \$(5) |
| Net realized(losses)/gains in the year ⁽³⁾ | \$(8) | \$47 | \$39 | \$5 |
| Maturity dates | 2008-2016 | 2008-2010 | 2008-2012 | 2008-2016 |
| Derivative Financial Instruments in Hedging Relationships⁽⁴⁾⁽⁵⁾ | | | | |
| Fair Values ⁽¹⁾ | | | | |
| Assets | \$135 | \$19 | \$— | \$2 |
| Liabilities | \$(104) | \$(7) | \$(62) | \$(16) |
| Notional Values | | | | |
| Volumes ⁽²⁾ | | | | |
| Purchases | 7,362 | 28 | — | — |
| Sales | 16,367 | 4 | — | — |
| Canadian dollars | — | — | — | 150 |
| U.S. dollars | — | — | U.S. 113 | U.S. 875 |
| Cross-currency | — | — | 136/U.S. 100 | — |
| Net realized (losses)/gains in the year ⁽³⁾ | \$(29) | \$18 | \$— | \$3 |
| Maturity dates | 2008-2013 | 2008-2010 | 2008-2013 | 2008-2013 |

⁽¹⁾ Fair value is equal to the carrying value of these derivatives.

⁽²⁾ Volumes for power and natural gas derivatives are in gigawatt hours and billion cubic feet, respectively.

⁽³⁾ All power and natural gas realized and unrealized gains and losses are included in Revenues. All interest rate and foreign exchange realized and unrealized gains and losses are included in Financial Charges and Interest Income and Other, respectively. Realized gains and losses are included in Net Income upon settlement of the financial instrument.

⁽⁴⁾ All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$2 million. In 2007, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

⁽⁵⁾ In 2007, Net Income included gains of \$7 million for the changes in fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2007, Net Income included a loss of \$4 million for the changes in fair value of an interest-rate cash flow hedge that was reclassified as a result of discontinuance of cash flow hedge accounting when the anticipated transaction was not likely to occur by the end of the originally specified time period.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|--|--------------|-------|
| Current | | |
| Other current assets | 318 | 160 |
| Accounts payable | (298) | (144) |
| Long-term | | |
| Other assets | 191 | 204 |
| Deferred amounts | (694) | (205) |

Derivative Financial Instruments of Joint Ventures

Included in the Balance Sheet Presentation of Derivative Financial Instruments table above are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was \$75 million at December 31, 2008 (2007 – \$75 million). These contracts mature from 2009 to 2014. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 7,600 gigawatt hours (GWh) at December 31, 2008 (2007 – 7,300 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 47 GWh at December 31, 2008 (2007 – 50 GWh).

NOTE 18 INCOME TAXES**Provision for Income Taxes**

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|-------------|------|------|
| Current | | | |
| Canada | 383 | 367 | 264 |
| Foreign | 143 | 65 | 37 |
| | 526 | 432 | 301 |
| Future | | | |
| Canada | (1) | 12 | 104 |
| Foreign | 77 | 46 | 71 |
| | 76 | 58 | 175 |
| | 602 | 490 | 476 |

Geographic Components of Income

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|-------|-------|
| Canada | 1,234 | 1,228 | 1,161 |
| Foreign | 938 | 582 | 444 |
| Income from continuing operations before income taxes and non-controlling interests | 2,172 | 1,810 | 1,605 |

Reconciliation of Income Tax Expense

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|--------------|-------|-------|
| Income from continuing operations before income taxes and non-controlling interests | 2,172 | 1,810 | 1,605 |
| Federal and provincial statutory tax rate | 29.5% | 32.1% | 32.5% |
| Expected income tax expense | 641 | 581 | 522 |
| Income tax differential related to regulated operations | 44 | 69 | 72 |
| Lower effective foreign tax rates | (5) | (39) | n/a |
| Tax rate and legislated changes | – | (72) | (33) |
| Income from equity investments and non-controlling interests | (45) | (34) | (27) |
| Change in valuation allowance | (9) | – | – |
| Other ⁽¹⁾ | (24) | (15) | (58) |
| Actual income tax expense | 602 | 490 | 476 |

⁽¹⁾ Includes net income tax benefits of \$5 million recorded in 2008 (\$2007 – \$13 million; 2006 – \$51 million) on the resolution of certain income tax matters with taxation authorities and changes in estimates.

Future Income Tax Assets and Liabilities

| <i>December 31 (millions of dollars)</i> | 2008 | 2007 |
|---|--------------|-------|
| Deferred amounts | 119 | 43 |
| Other post-employment benefits | 69 | 57 |
| Unrealized losses on derivatives | 62 | 22 |
| Unrealized foreign exchange losses on long-term debt | 77 | n/a |
| Non-capital loss carryforwards | 24 | n/a |
| Other | 137 | 77 |
| | 488 | 199 |
| Less: valuation allowance ⁽¹⁾ | 77 | 13 |
| Future income tax assets, net of valuation allowance | 411 | 186 |
| Difference in accounting and tax bases of plant, equipment and PPAs | 1,464 | 1,073 |
| Investments in subsidiaries and partnerships | 28 | 61 |
| Pension benefits | 55 | 50 |
| Unrealized foreign exchange gains on long-term debt | 14 | 110 |
| Unrealized gains on derivatives | 19 | 27 |
| Other | 54 | 44 |
| Future income tax liabilities | 1,634 | 1,365 |
| Net future income tax liabilities | 1,223 | 1,179 |

⁽¹⁾ A valuation allowance was recorded in 2008 as there is no virtual certainty that the Company will realize the tax benefit related to the unrealized foreign exchange losses on long-term debt in the future.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased by approximately \$102 million at December 31, 2008 (2007 – \$72 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of \$491 million were made during the year ended December 31, 2008 (2007 – \$442 million; 2006 – \$494 million).

NOTE 19 NOTES PAYABLE

| | 2008 | | 2007 | |
|---|----------------------------|---|----------------------------|---|
| | Outstanding December 31 | Weighted Average Interest Rate Per Annum at December 31 | Outstanding December 31 | Weighted Average Interest Rate Per Annum at December 31 |
| | (millions of dollars) | | (millions of dollars) | |
| Canadian dollars | 1,250 | 1.8% | 55 | 5.0% |
| U.S. dollars (2008 – US\$369; 2007 – US\$370) | 452 | 3.3% | 366 | 5.5% |
| | <u>1,702</u> | | <u>421</u> | |

Notes payable consists of commercial paper outstanding and drawings on bridge and line-of-credit facilities. Unsecured revolving and demand credit facilities totaled \$4.2 billion at December 31, 2008 to support the Company's commercial paper program and for general corporate purposes. These credit facilities included the following:

- a \$2.0 billion committed, syndicated, revolving credit facility maturing December 2012, which was fully available at December 31, 2008. The cost to maintain the credit facility was \$2 million in 2008 (2007 – \$2 million).
- a US\$300 million syndicated, revolving facility, maturing February 2013, which was fully available at December 31, 2008. This facility is part of the US\$1.0 billion committed, unsecured TransCanada PipeLine USA Ltd. credit facility established in February 2007.
- a US\$1.0 billion committed, extendible, expandable, revolving, unsecured, one-year agreement executed by TransCanada Keystone Pipeline L.P. in fourth quarter 2008 with a syndicate of banks, bearing interest at a floating rate, based on the greater of bank prime interest rates and LIBOR, plus a margin of not less than one per cent and not more than three per cent on revolving loans and not less than three per cent and not more than 6.5 per cent if drawn as a term loan. The agreement is extendible at the option of the Keystone partnership for an additional one-year term. As at December 31, 2008, this facility was fully available. This US\$1.0 billion agreement is guaranteed by TransCanada.
- demand lines totaling \$611 million, which support the issuance of letters of credit and provide additional liquidity. The Company had used approximately \$433 million of its total lines of credit for letters of credit at December 31, 2008. When 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.

In June 2008, TransCanada executed an agreement with a syndicate of banks for a US\$1.5 billion, committed, unsecured, one-year bridge loan facility, at a floating interest rate based on LIBOR plus 30 basis points. The facility is extendible at the option of the Company for an additional six-month term at LIBOR plus 35 basis points. In August 2008, the Company used US\$255 million from this facility and cancelled the remainder of the commitment. At December 31, 2008, US\$255 million remained outstanding on the facility.

In February 2007, the Company established a US\$2.2 billion committed, unsecured one-year bridge facility and utilized \$1.5 billion and US\$700 million to partially finance the acquisition of ANR and an increased ownership in Great Lakes. The facility had a floating interest rate based on the one-month LIBOR plus 25 basis points. The outstanding balance at December 31, 2007 of US\$370 million was repaid on January 7, 2008. The undrawn balance of this facility has been cancelled and is no longer available to the Company.

NOTE 20 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the regulated and non-regulated operations in the Pipelines segment were \$69 million at December 31, 2008 (2007 – \$65 million), calculated using an inflation rate ranging from two per cent to four per cent per annum. The estimated fair value of these liabilities was \$31 million at December 31, 2008 (2007 – \$25 million) after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from one year to 27 years. Management believes it is reasonable to assume that all retirement costs associated with its regulated pipelines will be recovered through future tolls and, therefore, typically only records asset retirement obligations for its non-regulated pipelines.

The estimated undiscounted cash flows required to settle the asset retirement obligations with respect to the Energy segment were \$427 million at December 31, 2008 (2007 – \$216 million), calculated using an inflation rate ranging from two per cent to three per cent per annum. The estimated fair value of this liability was \$85 million at December 31, 2008 (2007 – \$63 million), after discounting the estimated cash flows at rates ranging from 5.4 per cent to 8.0 per cent. At December 31, 2008, the expected timing of payment for settlement of the obligations ranged from 10 years to 33 years.

Reconciliation of Asset Retirement Obligations⁽¹⁾

| <i>(millions of dollars)</i> | Pipelines | Energy | Total |
|---|-----------|-----------|------------|
| Balance at January 1, 2006 | 4 | 29 | 33 |
| New obligations and revisions in estimated cash flows | 4 | 6 | 10 |
| Accretion expense | 1 | 1 | 2 |
| Balance at December 31, 2006 | 9 | 36 | 45 |
| New obligations and revisions in estimated cash flows | 14 | 25 | 39 |
| Accretion expense | 2 | 2 | 4 |
| Balance at December 31, 2007 | 25 | 63 | 88 |
| New obligations and revisions in estimated cash flows | 4 | 18 | 22 |
| Accretion expense | 2 | 4 | 6 |
| Balance at December 31, 2008 | 31 | 85 | 116 |

⁽¹⁾ At December 31, 2008, Asset Retirement Obligations totalling \$114 million (2007 – \$88 million) and \$2 million (2007 – nil) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 21 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover substantially all employees. Pension 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 in the Canadian pension plan by a portion of the increase in the Consumer Price Index (CPI). Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years.

Effective January 1, 2008, the Company also provides its employees with a Savings Plan in Canada, a 401(k) Plan in the U.S. and 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 was approximately 11 years at December 31, 2008. Contributions to the Savings Plan and 401(k) Plan are expensed as incurred.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was \$90 million in 2008 (2007 – \$61 million; 2006 – \$104 million), including \$21 million in 2008 (2007 – \$8 million; 2006 – \$2 million) related to retirement savings plans.

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 at January 1, 2009, and the next required valuation will be as at January 1, 2010.

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|--|-----------------------|-------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Change in Benefit Obligation | | | | |
| Benefit obligation – beginning of year | 1,462 | 1,378 | 155 | 132 |
| Current service cost | 52 | 45 | 2 | 2 |
| Interest cost | 80 | 73 | 8 | 7 |
| Employee contributions | 3 | 4 | 1 | – |
| Benefits paid | (68) | (65) | (8) | (7) |
| Actuarial (gain)/loss | (261) | (22) | (21) | 8 |
| Foreign exchange rate changes | 35 | (16) | 10 | (6) |
| Plan amendment | – | – | (11) | – |
| Acquisition | 29 | 65 | 8 | 19 |
| Benefit obligation – end of year | 1,332 | 1,462 | 144 | 155 |
| Change in Plan Assets | | | | |
| Plan assets at fair value – beginning of year | 1,358 | 1,264 | 30 | 33 |
| Actual return on plan assets | (222) | 33 | (10) | 2 |
| Employer contributions | 62 | 46 | 7 | 7 |
| Employee contributions | 3 | 4 | 1 | – |
| Benefits paid | (68) | (65) | (8) | (7) |
| Foreign exchange rate changes | 32 | (17) | 6 | (5) |
| Acquisition | 28 | 93 | – | – |
| Plan assets at fair value – end of year | 1,193 | 1,358 | 26 | 30 |
| Funded status – plan deficit | (139) | (104) | (118) | (125) |
| Unamortized net actuarial loss | 340 | 299 | 33 | 44 |
| Unamortized past service costs | 25 | 28 | (1) | 7 |
| Accrued benefit asset/(liability), net of valuation allowance of nil | 226 | 223 | (86) | (74) |

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's balance sheet was as follows:

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|------------------------------|-----------------------|------|---------------------|------|
| | 2008 | 2007 | 2008 | 2007 |
| Other Assets | 226 | 223 | – | 5 |
| Deferred Amounts | – | – | (86) | (79) |
| Total | 226 | 223 | (86) | (74) |

Included in the above benefit obligation and fair value of plan assets at December 31 were the following amounts for plans that are not fully funded:

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|------------------------------|-----------------------|---------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Benefit obligation | (1,317) | (1,324) | (144) | (155) |
| Plan assets at fair value | 1,178 | 1,198 | 26 | 30 |
| Funded status – plan deficit | (139) | (126) | (118) | (125) |

The Company's expected contributions in 2009 are approximately \$140 million for the pension benefit plans and approximately \$27 million for the other benefit plans.

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

| <i>(millions of dollars)</i> | Pension Benefits | Other Benefits |
|------------------------------|------------------|----------------|
| 2009 | 77 | 8 |
| 2010 | 81 | 9 |
| 2011 | 84 | 9 |
| 2012 | 88 | 10 |
| 2013 | 91 | 10 |
| 2014 to 2018 | 510 | 59 |

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

| | Pension Benefit Plans | | Other Benefit Plans | |
|-------------------------------|-----------------------|-------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Discount rate | 6.65% | 5.30% | 6.50% | 5.50% |
| Rate of compensation increase | 3.65% | 3.50% | | |

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

| | Pension Benefit Plans | | | Other Benefit Plans | | |
|--|-----------------------|-------|-------|---------------------|-------|-------|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Discount rate | 5.30% | 5.05% | 5.00% | 5.50% | 5.20% | 5.15% |
| Expected long-term rate of return on plan assets | 6.95% | 6.90% | 6.90% | 7.75% | 7.75% | 7.75% |
| Rate of compensation increase | 3.60% | 3.50% | 3.50% | | | |

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining 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.

A nine per cent annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2009 measurement purposes. The rate was assumed to decrease gradually to five per cent in 2018 and remain at this level thereafter. A one percentage point change in assumed health care cost trend rates would have the following effects:

| <i>(millions of dollars)</i> | Increase | Decrease |
|---|----------|----------|
| Effect on total of service and interest cost components | 1 | (1) |
| Effect on post-employment benefit obligation | 11 | (10) |

The Company's net benefit cost is as follows:

| <i>Year ended December 31 (millions of dollars)</i> | Pension Benefit Plans | | | Other Benefit Plans | | |
|--|-----------------------|------|-------|---------------------|------|------|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Current service cost | 52 | 45 | 39 | 2 | 2 | 3 |
| Interest cost | 80 | 73 | 65 | 8 | 7 | 8 |
| Actual return on plan assets | 222 | (33) | (134) | 10 | (2) | (6) |
| Actuarial (gain)/loss | (261) | (22) | 53 | (21) | 8 | (2) |
| Plan amendment | – | – | – | (11) | – | (18) |
| Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost | 93 | 63 | 23 | (12) | 15 | (15) |
| Difference between expected and actual return on plan assets | (316) | (51) | 63 | (12) | (1) | 4 |
| Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation | 280 | 47 | (27) | 23 | (7) | 4 |
| Difference between amortization of past service costs and actual plan amendments | 4 | 4 | 4 | 11 | – | 19 |
| Amortization of transitional obligation related to regulated business | – | – | – | 2 | 2 | 2 |
| Net benefit cost recognized | 61 | 63 | 63 | 12 | 9 | 14 |

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

| <i>December 31</i> | Percentage of Plan Assets | | Target Allocations |
|-----------------------|---------------------------|------|--------------------|
| | 2008 | 2007 | 2008 |
| Asset Category | | | |
| Debt securities | 48% | 42% | 35% to 60% |
| Equity securities | 52% | 58% | 40% to 65% |
| | 100% | 100% | |

Debt securities included the Company's debt of \$3 million (0.3 per cent of total plan assets) and \$4 million (0.3 per cent of total plan assets) at December 31, 2008 and 2007, respectively. Equity securities included the Company's common shares of \$4 million (0.3 per cent of total plan assets) and \$6 million (0.4 per cent of total plan assets) at December 31, 2008 and 2007, 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 following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was \$42 million in 2008 (2007 – \$34 million; 2006 – \$25 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2009, and the next required valuations will be as at January 1, 2010.

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|--|-----------------------|-------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Change in Benefit Obligation | | | | |
| Benefit obligation – beginning of year | 789 | 807 | 165 | 169 |
| Current service cost | 27 | 28 | 8 | 10 |
| Interest cost | 42 | 40 | 9 | 8 |
| Employee contributions | 6 | 5 | – | – |
| Benefits paid | (37) | (23) | (4) | (2) |
| Actuarial gain | (229) | (34) | (45) | (16) |
| Foreign exchange rate changes | 1 | (3) | – | – |
| Acquisition | – | (31) | – | (2) |
| Plan amendment | – | – | – | (2) |
| Benefit obligation – end of year | 599 | 789 | 133 | 165 |
| Change in Plan Assets | | | | |
| Plan assets at fair value – beginning of year | 626 | 666 | – | – |
| Actual return on plan assets | (78) | (1) | – | – |
| Employer contributions | 38 | 32 | 4 | 2 |
| Employee contributions | 6 | 5 | – | – |
| Benefits paid | (37) | (23) | (4) | (2) |
| Foreign exchange rate changes | 1 | (5) | – | – |
| Acquisition | – | (48) | – | – |
| Plan assets at fair value – end of year | 556 | 626 | – | – |
| Funded status – plan deficit | (43) | (163) | (133) | (165) |
| Unamortized net actuarial loss/(gain) | 51 | 169 | (3) | 45 |
| Unamortized past service costs | – | – | 3 | 3 |
| Accrued benefit asset/(liability), net of valuation allowance of nil | 8 | 6 | (133) | (117) |

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

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|------------------------------|-----------------------|------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Other Assets | 8 | 6 | – | – |
| Deferred Amounts | – | – | (133) | (117) |
| Total | 8 | 6 | (133) | (117) |

The following amounts were included at December 31 in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

| <i>(millions of dollars)</i> | Pension Benefit Plans | | Other Benefit Plans | |
|------------------------------|-----------------------|-------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Benefit obligation | (594) | (786) | (133) | (165) |
| Plan assets at fair value | 551 | 623 | – | – |
| Funded status – plan deficit | (43) | (163) | (133) | (165) |

The expected total contributions of the Company's joint ventures in 2009 are approximately \$37 million for the pension benefit plans and approximately \$4 million for the other benefit plans.

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

| <i>(millions of dollars)</i> | Pension Benefits | Other Benefits |
|------------------------------|------------------|----------------|
| 2009 | 39 | 4 |
| 2010 | 43 | 5 |
| 2011 | 46 | 6 |
| 2012 | 50 | 7 |
| 2013 | 54 | 7 |
| 2014 to 2018 | 325 | 49 |

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

| | Pension Benefit Plans | | Other Benefit Plans | |
|-------------------------------|-----------------------|-------|---------------------|-------|
| | 2008 | 2007 | 2008 | 2007 |
| Discount rate | 6.70% | 5.25% | 6.40% | 5.15% |
| Rate of compensation increase | 3.50% | 3.50% | | |

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures for years ended December 31 were as follows:

| | Pension Benefit Plans | | | Other Benefit Plans | | |
|--|-----------------------|-------|-------|---------------------|-------|-------|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Discount rate | 5.25% | 5.00% | 5.25% | 5.15% | 4.90% | 5.15% |
| Expected long-term rate of return on plan assets | 7.00% | 7.00% | 7.30% | | | |
| Rate of compensation increase | 3.50% | 3.50% | 3.50% | | | |

A one percentage point change in assumed health care cost trend rates would have the following effects:

| <i>(millions of dollars)</i> | Increase | Decrease |
|---|----------|----------|
| Effect on total of service and interest cost components | 3 | (2) |
| Effect on post-employment benefit obligation | 17 | (14) |

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

| <i>Year ended December 31 (millions of dollars)</i> | Pension Benefit Plans | | | Other Benefit Plans | | |
|--|-----------------------|------|------|---------------------|------|------|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Current service cost | 27 | 28 | 24 | 8 | 10 | 7 |
| Interest cost | 42 | 40 | 37 | 9 | 8 | 5 |
| Actual return on plan assets | 78 | 1 | (68) | - | - | - |
| Actuarial (gain)/loss | (229) | (34) | 77 | (45) | (16) | 72 |
| Plan amendment | - | - | - | - | (2) | 6 |
| Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost | (82) | 35 | 70 | (28) | - | 90 |
| Difference between expected and actual return on plan assets | (122) | (44) | 26 | - | - | - |
| Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation | 239 | 44 | (70) | 48 | 20 | (72) |
| Difference between amortization of past service costs and actual plan amendments | - | - | - | - | 3 | (6) |
| Net benefit cost recognized related to joint ventures | 35 | 35 | 26 | 20 | 23 | 12 |

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

| <i>December 31</i> | Percentage of Plan Assets | | Target Allocations |
|-----------------------|---------------------------|------|--------------------|
| | 2008 | 2007 | 2008 |
| Asset Category | | | |
| Debt securities | 44% | 43% | 40% |
| Equity securities | 56% | 57% | 60% |
| | 100% | 100% | |

Debt securities included the Company's debt of \$1 million (0.2 per cent of total plan assets) and \$1 million (0.2 per cent of total plan assets) at December 31, 2008 and 2007, respectively. Equity securities included the Company's common shares of \$3 million (0.6 per cent of total plan assets) and \$3 million (0.5 per cent of total plan assets) at December 31, 2008 and 2007, 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 22 CHANGES IN OPERATING WORKING CAPITAL

| <i>Year ended December 31 (millions of dollars)</i> | 2008 | 2007 | 2006 |
|---|-------|------|-------|
| (Increase)/decrease in accounts receivable | (197) | 51 | (188) |
| Decrease/(increase) in inventories | 82 | (6) | (108) |
| (Increase)/decrease in other current assets | (146) | 118 | (6) |
| (Decrease)/increase in accounts payable | (18) | 61 | (42) |
| Increase/(decrease) in accrued interest | 98 | (9) | 41 |
| | (181) | 215 | (303) |

NOTE 23 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 and equipment are approximately as follows:

| <i>Year ended December 31 (millions of dollars)</i> | Minimum Lease Payments | Amounts Recoverable under Sub-leases | Net Payments |
|---|------------------------|--------------------------------------|--------------|
| 2009 | 40 | (12) | 28 |
| 2010 | 39 | (12) | 27 |
| 2011 | 39 | (10) | 29 |
| 2012 | 38 | (5) | 33 |
| 2013 | 37 | (4) | 33 |
| 2014 and thereafter | 260 | (7) | 253 |
| Total | 453 | (50) | 403 |

The operating lease agreements for premises, services and equipment expire at various dates through 2035, with an option to renew certain lease agreements for periods of one year to ten years. Net rental expense on operating leases in 2008 was \$52 million (2007 – \$34 million; 2006 – \$25 million).

TransCanada's commitments under the acquired Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from the above table, as these payments are dependent upon plant availability, among other factors. The amount of power purchased under the PPAs in 2008 was \$471 million (2007 – \$440 million; 2006 – \$499 million). The generating capacities and expiry dates of the PPAs are as follows:

| | Megawatts | Expiry Date |
|------------|-----------|-------------------|
| Sundance A | 560 | December 31, 2017 |
| Sundance B | 353 | December 31, 2020 |
| Sheerness | 756 | December 31, 2020 |

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

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2 and refurbishing Units 3 and 4 to extend their operating life. TransCanada's share of these signed commitments, which extend over the three-year period ending December 31, 2011, are as follows:

Year ended December 31 (millions of dollars)

| | |
|------|-----|
| 2009 | 204 |
| 2010 | 49 |
| 2011 | 2 |
| | 255 |

Loan-Aboriginal Pipeline Group

On June 18, 2003, the Mackenzie Delta gas producers, the APG and TransCanada reached an agreement governing TransCanada's role in the Mackenzie Gas Pipeline (MGP) 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 pre-development costs. These costs, on a cumulative basis, are currently forecast to be between \$150 million and \$200 million, depending upon the pace of project development. As at December 31, 2008, the Company had advanced \$140 million to the APG.

TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. Detailed discussions with the Canadian government are continuing, and project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project, including a review by TransCanada of the carrying value of advances to the APG.

Other Commitments

TransCanada is committed to capital expenditures totalling approximately \$2.3 billion related to its share of the construction costs of Keystone, North Central Corridor and other pipeline projects.

The Company is committed to capital expenditures totalling approximately \$1.0 billion related to its share of the construction costs of Coolidge, Bruce Power, the remaining Cartier Wind projects, Halton Hills and Portlands Energy.

Contingencies

On April 3, 2008, the Ontario Court of Appeal dismissed an appeal filed by the Canadian Alliance of Pipeline Landowners' Associations (CAPLA). CAPLA filed the appeal as a result of a decision by the Ontario Superior Court in November 2006 to dismiss CAPLA's class action lawsuit against TransCanada and Enbridge Inc. for damages alleged to have arisen from the creation of a control zone within 30 metres of a pipeline pursuant to Section 112 of the *National Energy Board Act*. The Ontario Court of Appeal's decision is final and binding as CAPLA did not seek any further appeal within the time frame allowed.

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2008, the Company accrued approximately \$83 million related to operating facilities and \$3 million related to discontinued operation sites. The accrued amount represents the Company's estimate of the amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various 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

TransCanada, Cameco Corporation and BPC Generation Infrastructure Trust (BPC) have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, operator licenses, a lease agreement and contractor services. The guarantees have terms ranging from one year ending in 2010 to perpetuity. In addition, TransCanada and BPC have severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated at December 31, 2008 to range from \$711 million to a maximum of \$750 million. The fair value of these guarantees is estimated to be \$17 million.

The Company and its partners in certain jointly owned entities have severally as well as jointly and severally guaranteed the financial performance of these entities related primarily to construction projects, redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2008 to range from \$688 million to a maximum of \$1.4 billion. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners. Deferred Amounts includes \$9 million for the fair value of these joint and several guarantees.

TransCanada has guaranteed a subsidiary's equity undertaking to support the payment, under certain conditions, of principal and interest on US\$43 million of the public debt obligations of TransGas de Occidente S.A. (TransGas). The Company has a 46.5 per cent interest in TransGas. Under the terms of a shareholder agreement, TransCanada and another major multinational company may be required to severally 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 would convert into share capital of TransGas. The Company's potential exposure is contingent on the impact any change of law would have on the ability of TransGas to service the debt. There has been no change in applicable law since the issuance of debt in 1995 and, thus, no exposure for TransCanada. The debt matures in 2010. The Company has made no provision related to this guarantee.

NOTE 24 DISCONTINUED OPERATIONS

The \$28 million income from discontinued operations in 2006 reflected settlements received from bankruptcy claims related to TransCanada's Gas Marketing business, which was sold in 2001.