Management's report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada PipeLines Limited (TCPL or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2014 to that in 2013, and highlights significant changes between 2013 and 2012. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2014, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholder.

The shareholder has appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 12, 2015

Independent Auditors' Report

TO THE SHAREHOLDER OF TRANSCANADA PIPELINES LIMITED

We have audited the accompanying consolidated financial statements of TransCanada PipeLines Limited, which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, the consolidated statements of income, cash flows, comprehensive income, and equity for each of the years in the three-year period ended December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada PipeLines Limited as at December 31, 2014 and December 31, 2013, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2014 in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 12, 2015

Consolidated statement of income

year ended December 31 (millions of Canadian dollars)	**2014**	**2013**	**2012**
Revenues			
Natural Gas Pipelines	**4,913**	4,497	4,264
Liquids Pipelines	**1,547**	1,124	1,039
Energy	**3,725**	3,176	2,704
	10,185	8,797	8,007
Income from Equity Investments (Note 8)	**522**	597	257
Operating and Other Expenses			
Plant operating costs and other	**2,973**	2,674	2,577
Commodity purchases resold	**1,836**	1,317	1,049
Property taxes	**473**	445	434
Depreciation and amortization	**1,611**	1,485	1,375
	6,893	5,921	5,435
Gain on Sale of Assets (Note 25)	**117**	–	–
Financial Charges/(Income)			
Interest expense (Note 15)	**1,235**	1,046	1,037
Interest income and other	**(128)**	(72)	(125)
	1,107	974	912
Income before Income Taxes	**2,824**	2,499	1,917
Income Tax Expense (Note 16)			
Current	**146**	43	185
Deferred	**684**	562	276
	830	605	461
Net Income	**1,994**	1,894	1,456
Net Income Attributable to Non-Controlling Interests (Note 18)	**151**	105	96
Net Income Attributable to Controlling Interests	**1,843**	1,789	1,360
Preferred Share Dividends (Note 20)	**2**	20	22
Net Income Attributable to Common Shares	**1,841**	1,769	1,338

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

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Net Income	**1,994**	1,894	1,456
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investments in foreign operations	**517**	383	(129)
Change in fair value of net investment hedges	**(276)**	(239)	44
Change in fair value of cash flow hedges	**(69)**	71	48
Reclassification to Net Income of gains and losses on cash flow hedges	**(55)**	41	138
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(102)**	67	(73)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**18**	23	22
Other Comprehensive Income/(Loss) on equity investments	**(204)**	234	(70)
Other Comprehensive Income/(Loss) (Note 21)	**(171)**	580	(20)
Comprehensive Income	**1,823**	2,474	1,436
Comprehensive Income Attributable to Non-Controlling Interests	**281**	171	75
Comprehensive Income Attributable to Controlling Interests	**1,542**	2,303	1,361
Preferred Share Dividends	**2**	20	22
Comprehensive Income Attributable to Common Shares	**1,540**	2,283	1,339

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

Consolidated statement of cash flows

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Cash Generated from Operations			
Net income	**1,994**	1,894	1,456
Depreciation and amortization	**1,611**	1,485	1,375
Deferred income taxes (Note 16)	**684**	562	276
Income from equity investments (Note 8)	**(522)**	(597)	(257)
Distributed earnings received from equity investments (Note 8)	**579**	605	376
Employee post-retirement benefits expense, net of funding (Note 22)	**37**	50	9
Gain on sale of assets (Note 25)	**(117)**	–	–
Equity AFUDC (Note 9)	**(95)**	(19)	(15)
Unrealized losses/(gains) on financial instruments	**74**	(35)	22
Other	**22**	32	17
(Increase)/decrease in operating working capital (Note 24)	**(189)**	(334)	287
Net cash provided by operations	**4,078**	3,643	3,546
Investing Activities			
Capital expenditures (Note 4)	**(3,550)**	(4,264)	(2,595)
Capital projects under development (Note 4)	**(807)**	(488)	(3)
Equity investments	**(256)**	(163)	(652)
Acquisitions, net of cash acquired (Note 25)	**(241)**	(216)	(214)
Proceeds from sale of assets, net of transaction costs (Note 25)	**196**	–	–
Deferred amounts and other	**514**	11	208
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)
Financing Activities			
Dividends on common shares (Note 19)	**(1,345)**	(1,286)	(1,226)
Dividends on preferred shares (Note 20)	**(4)**	(22)	(22)
Distributions paid to non-controlling interests	**(174)**	(146)	(113)
Advances to affiliates, net	**(694)**	(297)	(235)
Notes payable issued/(repaid), net	**544**	(492)	449
Long-term debt issued, net of issue costs	**1,403**	4,253	1,491
Repayment of long-term debt	**(1,069)**	(1,286)	(980)
Common shares issued	**1,115**	899	269
Partnership units of subsidiary issued, net of issue costs	**79**	384	–
Preferred shares redeemed (Note 20)	**(200)**	(200)	–
Net cash (used in)/provided by financing activities	**(345)**	1,807	(367)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**–**	28	(15)
(Decrease)/Increase in Cash and Cash Equivalents	**(411)**	358	(92)
Cash and Cash Equivalents			
Beginning of year	**895**	537	629
Cash and Cash Equivalents			
End of year	**484**	895	537

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

Consolidated balance sheet

at December 31 (millions of Canadian dollars)	2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	**484**	895
Accounts receivable	**1,372**	1,165
Due from affiliates (Note 27)	**2,842**	2,721
Inventories	**292**	251
Other (Note 5)	**1,445**	845
	6,435	5,877
Plant, Property and Equipment (Note 7)	**41,774**	37,606
Equity Investments (Note 8)	**5,598**	5,759
Regulatory Assets (Note 9)	**1,297**	1,735
Goodwill (Note 10)	**4,034**	3,696
Intangible and Other Assets (Note 11)	**2,700**	1,953
	61,838	56,626
LIABILITIES		
Current Liabilities		
Notes payable (Note 12)	**2,467**	1,842
Accounts payable and other (Note 13)	**2,895**	2,141
Due to affiliates (Note 27)	**866**	1,439
Accrued interest	**425**	389
Current portion of long-term debt (Note 15)	**1,797**	973
	8,450	6,784
Regulatory Liabilities (Note 9)	**263**	229
Other Long-Term Liabilities (Note 14)	**1,052**	656
Deferred Income Tax Liabilities (Note 16)	**5,275**	4,564
Long-Term Debt (Note 15)	**22,960**	21,892
Junior Subordinated Notes (Note 17)	**1,160**	1,063
	39,160	35,188
EQUITY		
Common shares, no par value (Note 19)	**16,320**	15,205
Issued and outstanding: December 31, 2014 – 779 million shares December 31, 2013 – 757 million shares		
Preferred shares (Note 20)	**–**	194
Additional paid-in capital	**404**	431
Retained earnings	**5,606**	5,125
Accumulated other comprehensive loss (Note 21)	**(1,235)**	(934)
Controlling interests	**21,095**	20,021
Non-controlling interests (Note 18)	**1,583**	1,417
	22,678	21,438
	61,838	56,626

Commitments, Contingencies and Guarantees (Note 26)

Subsequent Events (Note 28)

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

On behalf of the Board:

Russell K. Girling
Director

Kevin E. Benson
Director

Consolidated statement of equity

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Common Shares			
Balance at beginning of year	**15,205**	14,306	14,037
Proceeds from shares issued (Note 19)	**1,115**	899	269
Balance at end of year	**16,320**	15,205	14,306
Preferred Shares			
Balance at beginning of year	**194**	389	389
Redemption of preferred shares	**(194)**	(195)	–
Balance at end of year	**–**	194	389
Additional Paid-In Capital			
Balance at beginning of year	**431**	400	394
Dilution impact from TC PipeLines, LP units issued (Note 25)	**9**	29	–
Redemption of preferred shares	**(6)**	(5)	–
Impact of asset drop downs to TC Pipelines, LP (Note 25)	**(37)**	–	–
Other	**7**	7	6
Balance at end of year	**404**	431	400
Retained Earnings			
Balance at beginning of year	**5,125**	4,657	4,561
Net income attributable to controlling interests	**1,843**	1,789	1,360
Common share dividends	**(1,360)**	(1,301)	(1,242)
Preferred share dividends	**(2)**	(20)	(22)
Balance at end of year	**5,606**	5,125	4,657
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(934)**	(1,448)	(1,449)
Other comprehensive (loss)/income	**(301)**	514	1
Balance at end of year	**(1,235)**	(934)	(1,448)
Equity Attributable to Controlling Interests	**21,095**	20,021	18,304
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,417**	1,036	1,076
Net income attributable to non-controlling interests			
TC PipeLines, LP	**136**	93	91
Portland	**15**	12	5
Other comprehensive income/(loss) attributable to non-controlling interests	**130**	66	(21)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**79**	384	–
Decrease in TCPL's ownership of TC PipeLines, LP	**(14)**	(47)	–
Distributions declared to non-controlling interests	**(180)**	(146)	(113)
Foreign exchange and other	**–**	19	(2)
Balance at end of year	**1,583**	1,417	1,036
Total Equity	**22,678**	21,438	19,340

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

Notes to consolidated financial statements

1. DESCRIPTION OF TCPL'S BUSINESS

TransCanada PipeLines Limited (TCPL or the Company) is a leading North American energy infrastructure company which operates in three business segments, Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services. The Company is a wholly owned subsidiary of TransCanada Corporation (TransCanada).

Natural Gas Pipelines

The Natural Gas Pipelines segment consists of the Company's investments in 68,000 km (42,000 miles) of regulated natural gas pipelines and 400 Bcf of regulated natural gas storage facilities. These assets are located in Canada, the United States and Mexico.

Liquids Pipelines

The Liquids Pipelines segment consists of 4,250 km (2,600 miles) of wholly owned and operated crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy

The Energy segment primarily consists of the Company's investments in 19 electrical power generation plants and 2 non-regulated natural gas storage facilities. These include Canadian plants in Alberta, Ontario, Québec and New Brunswick and U.S. plants in New York, New England and Arizona.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

The consolidated financial statements include the accounts of TCPL and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TCPL uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TCPL records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to:

- carrying values and depreciation rates of plant, property and equipment (Note 7);
- carrying value of equity investments (Note 8);
- carrying value of regulatory assets and liabilities (Note 9);
- carrying value of goodwill (Note 10);

- amortization rates and carrying values of intangible assets (Note 11);
- carrying value of asset retirement obligations (Note 14);
- provisions for income taxes (Note 16);
- assumptions used to measure retirement and other postretirement obligations (Note 22);
- fair value of financial instruments (Note 23); and
- provision for commitments, contingencies and guarantees (Note 26).

Actual results could differ from those estimates.

Regulation

In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB) of Canada. In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission of Mexico (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TCPL's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TCPL's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain of our liquids pipelines projects. RRA is not applicable to the Keystone Pipeline System and, as a result, the regulators' decisions regarding operations and tolls on that system generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas and Liquids Pipelines

Revenues from the Company's natural gas and liquids pipelines, with the exception of Canadian natural gas pipelines which are subject to RRA, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made. The U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized at the time of the regulatory decision.

Revenues from Canadian natural gas pipelines subject to RRA are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are periodically subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues are recognized on firm contracted capacity ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved rate of return on common equity (ROE) assumptions. Adjustments to revenue are recorded when the NEB decision is received.

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas or oil that it transports or stores for others.

Energy

Power

Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative Instruments and Hedging Activities section of this note.

Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas 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

Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates, reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in plant, property and equipment and the equity component of AFUDC is a non-cash expenditure with a corresponding credit recognized in Interest Income and Other. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas 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.

Liquids Pipelines

Plant, property and equipment for liquids pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction for non-regulated liquids pipelines and AFUDC for regulated pipelines. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy
Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

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

Impairment of Long-Lived Assets
The Company reviews long-lived assets, such as plant, property 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 acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the asset might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. If TCPL concludes that it is not more likely than not that fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts 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 goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

Power Purchase Arrangements
A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. Substantially all PPAs under which TCPL buys power are accounted for as operating leases. Initial payments for these PPAs were recognized in Intangible and Other Assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TCPL records the margin earned from the subleases as a component of Revenues.

Income Taxes
The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in income in the period during which they

occur except for changes in balances related to the Canadian Mainline, NGTL System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

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.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation 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 through charges to operating expenses.

Recorded ARO relates to the non-regulated natural gas storage operations and certain power generation facilities. The scope and timing of asset retirements related to natural gas pipelines, liquids pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities.

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. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are utilized. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TCPL are not attributed a value for accounting purposes. When required, TCPL accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

The Stock Option Plan permits options for the purchase of TransCanada common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period, with an offset to Additional Paid-In Capital.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received 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 age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. 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 Plans' 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 life of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive Income (OCI) in the year in which the change occurs. 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 out of Accumulated Other Comprehensive Loss (AOCI) over the average remaining service life 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.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt has been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if 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.

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 and these changes 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 Interest Expense, respectively. If 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 initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net Income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities and are refunded to or collected from the ratepayers, in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms 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. When changes in the fair value of embedded derivatives are measured separately, they are included in Net Income.

Long-Term Debt Transaction Costs

The Company records Long-Term Debt transaction costs as other assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. 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 as appropriate in the circumstances. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Other Long-Term Liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2014

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This new guidance was effective January 1, 2014 and there was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Foreign currency matters – cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This new guidance was applied prospectively from January 1, 2014 and there was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This new guidance was effective January 1, 2014. There was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Future Accounting Changes

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Revenue from contracts with customers

In May 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. The Company is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2014 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,913	1,547	3,725	–	10,185
Income from Equity Investments	163	–	359	–	522
Plant Operating Costs and Other	(1,501)	(426)	(919)	(127)	(2,973)
Commodity Purchases Resold	–	–	(1,836)	–	(1,836)
Property Taxes	(334)	(62)	(77)	–	(473)
Depreciation and Amortization	(1,063)	(216)	(309)	(23)	(1,611)
Gain on Sale of Assets	9	–	108	–	117
Segment earnings	2,187	843	1,051	(150)	3,931
Interest Expense					(1,235)
Interest Income and Other					128
Income before Income Taxes					2,824
Income Tax Expense					(830)
Net Income					1,994
Net Income Attributable to Non-Controlling Interests					(151)
Net Income Attributable to Controlling Interests					1,843
Preferred Share Dividends					(2)
Net Income Attributable to Common Shares					1,841
Capital Spending					
Capital Expenditures	1,768	1,530	206	46	3,550
Projects Under Development	368	439	–	–	807
	2,136	1,969	206	46	4,357

at December 31, 2014 (millions of Canadian dollars)					
Total Assets	27,103	16,116	14,197	4,422	61,838

year ended December 31, 2013 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,497	1,124	3,176	–	8,797
Income from Equity Investments	145	–	452	–	597
Plant Operating Costs and Other	(1,405)	(328)	(833)	(108)	(2,674)
Commodity Purchases Resold	–	–	(1,317)	–	(1,317)
Property Taxes	(329)	(44)	(72)	–	(445)
Depreciation and Amortization	(1,027)	(149)	(293)	(16)	(1,485)
Segment earnings	1,881	603	1,113	(124)	3,473
Interest Expense					(1,046)
Interest Income and Other					72
Income before Income Taxes					2,499
Income Tax Expense					(605)
Net Income					1,894
Net Income Attributable to Non-Controlling Interests					(105)
Net Income Attributable to Controlling Interests					1,789
Preferred Share Dividends					(20)
Net Income Attributable to Common Shares					1,769
Capital Spending					
Capital Expenditures	1,776	2,286	152	50	4,264
Projects Under Development	245	243	–	–	488
	2,021	2,529	152	50	4,752

at December 31, 2013 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Total Assets	25,165	13,253	13,747	4,461	56,626

year ended December 31, 2012 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,264	1,039	2,704	–	8,007
Income from Equity Investments	157	–	100	–	257
Plant Operating Costs and Other	(1,365)	(296)	(819)	(97)	(2,577)
Commodity Purchases Resold	–	–	(1,049)	–	(1,049)
Property Taxes	(315)	(45)	(74)	–	(434)
Depreciation and Amortization	(933)	(145)	(283)	(14)	(1,375)
Segment earnings	1,808	553	579	(111)	2,829
Interest Expense					(1,037)
Interest Income and Other					125
Income before Income Taxes					1,917
Income Tax Expense					(461)
Net Income					1,456
Net Income Attributable to Non-Controlling Interests					(96)
Net Income Attributable to Controlling Interests					1,360
Preferred Share Dividends					(22)
Net Income Attributable to Common Shares					1,338
Capital Spending					
Capital Expenditures	1,389	1,145	24	37	2,595
Projects Under Development	–	3	–	–	3
	1,389	1,148	24	37	2,598

at December 31, 2012 (millions of Canadian dollars)					
Total Assets	23,210	10,485	13,157	2,483	49,335

Geographic Information

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Revenues			
Canada – domestic	**4,021**	4,659	3,527
Canada – export	**1,314**	997	1,121
United States	**4,653**	3,029	3,252
Mexico	**197**	112	107
	10,185	8,797	8,007

at December 31 (millions of Canadian dollars)	2014	2013
Plant, Property and Equipment		
Canada	**19,191**	18,462
United States	**20,098**	17,570
Mexico	**2,485**	1,574
	41,774	37,606

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian dollars)	2014	2013
Deferred income tax assets (Note 16)	**427**	117
Cash held as collateral	**423**	42
Fair value of derivative contracts (Note 23)	**409**	395
Other	**170**	164
Regulatory Assets (Note 9)	**16**	42
Assets held for sale (Note 6)	**–**	85
	1,445	845

6. ASSETS HELD FOR SALE

at December 31 (millions of Canadian dollars)	2013
Assets Held for Sale	
Cash and Cash Equivalents	**1**
Accounts Receivable	**12**
Inventories	**11**
Plant, Property and Equipment	**61**
Total Assets Held for Sale (included in Other Current Assets, Note 5)	**85**
Liabilities Related to Assets Held for Sale	
Accounts Payable and Other	**4**
Other Long-Term Liabilities	**1**
Total Liabilities Related to Assets Held for Sale (included in Accounts Payable and Other, Note 13)	**5**

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market an asset for sale and expects the sale to close within the next twelve months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and depreciation expense is no longer recorded for that asset.

At December 31, 2013, the Company classified Cancarb Limited and its related power generation facility as assets held for sale in the Energy segment. The assets were recorded at their carrying amount at December 31, 2013.

On April 15, 2014, the Company sold these assets for aggregate gross proceeds of $190 million and recognized a gain of $108 million ($99 million after tax).

7. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian dollars)	2014			2013		
	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Natural Gas Pipelines						
Canadian Mainline						
Pipeline	**9,045**	**5,712**	**3,333**	8,970	5,457	3,513
Compression	**3,423**	**2,100**	**1,323**	3,392	1,961	1,431
Metering and other	**458**	**180**	**278**	409	174	235
	12,926	**7,992**	**4,934**	12,771	7,592	5,179
Under construction	**135**	**–**	**135**	85	–	85
	13,061	**7,992**	**5,069**	12,856	7,592	5,264
NGTL System						
Pipeline	**8,185**	**3,619**	**4,566**	7,813	3,410	4,403
Compression	**2,055**	**1,318**	**737**	2,038	1,253	785
Metering and other	**1,032**	**446**	**586**	947	418	529
	11,272	**5,383**	**5,889**	10,798	5,081	5,717
Under construction	**413**	**–**	**413**	290	–	290
	11,685	**5,383**	**6,302**	11,088	5,081	6,007
ANR						
Pipeline	**1,087**	**85**	**1,002**	922	59	863
Compression	**741**	**102**	**639**	635	81	554
Metering and other	**617**	**110**	**507**	535	91	444
	2,445	**297**	**2,148**	2,092	231	1,861
Under construction	**115**	**–**	**115**	67	–	67
	2,560	**297**	**2,263**	2,159	231	1,928
Other Natural Gas Pipelines						
GTN	**1,842**	**588**	**1,254**	1,685	488	1,197
Great Lakes	**1,807**	**939**	**868**	1,650	833	817
Foothills	**1,671**	**1,180**	**491**	1,649	1,120	529
Mexico	**1,518**	**130**	**1,388**	641	90	551
Other[1]	**1,800**	**363**	**1,437**	1,652	288	1,364
	8,638	**3,200**	**5,438**	7,277	2,819	4,458
Under construction	**1,132**	**–**	**1,132**	1,047	–	1,047
	9,770	**3,200**	**6,570**	8,324	2,819	5,505
	37,076	**16,872**	**20,204**	34,427	15,723	18,704
Liquids Pipelines						
Keystone						
Pipeline	**7,931**	**463**	**7,468**	5,079	286	4,793
Pumping equipment	**964**	**80**	**884**	1,118	82	1,036
Tanks and other	**2,282**	**144**	**2,138**	962	71	891
	11,177	**687**	**10,490**	7,159	439	6,720
Under construction[2]	**4,438**	**–**	**4,438**	6,020	–	6,020
	15,615	**687**	**14,928**	13,179	439	12,740
Energy						
Natural Gas – Ravenswood	**2,140**	**476**	**1,664**	1,966	377	1,589
Natural Gas – Other[3,4]	**3,214**	**971**	**2,243**	3,061	846	2,215
Hydro	**736**	**156**	**580**	673	126	547
Wind	**970**	**190**	**780**	946	155	791
Natural Gas Storage	**653**	**99**	**554**	677	92	585
Solar[5]	**488**	**13**	**475**	226	2	224
Other	**64**	**19**	**45**	57	30	27
	8,265	**1,924**	**6,341**	7,606	1,628	5,978
Under construction	**149**	**–**	**149**	54	–	54
	8,414	**1,924**	**6,490**	7,660	1,628	6,032
Corporate	**232**	**80**	**152**	191	61	130
	61,337	**19,563**	**41,774**	55,457	17,851	37,606

1 Includes Bison, Portland, North Baja, Tuscarora and Ventures LP.

2 Includes $3.2 billion for Keystone XL at December 31, 2014 (2013 – $2.6 billion). Keystone XL remains subject to regulatory approvals.

3 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $695 million and $103 million, respectively, at December 31, 2014 (2013 – $640 million and $78 million, respectively). Revenues of $81 million were recognized in 2014 (2013 – $78 million; 2012 – $73 million) through the sale of electricity under the related PPAs.

4 Includes Halton Hills, Coolidge, Bécancour, Ocean State Power, Mackay River and other natural gas-fired facilities.

5 Includes the acquisitions of four solar power facilities in each of 2014 and 2013.

8. EQUITY INVESTMENTS

		Income/(Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian dollars)	December 31, 2014	**2014**	**2013**	**2012**	**2014**	**2013**
Natural Gas Pipelines						
Northern Border[1,2]		**76**	66	72	**587**	557
Iroquois	44.5%	**43**	41	41	**210**	188
TQM	50.0%	**12**	13	16	**73**	76
Other	Various	**32**	25	28	**68**	62
Energy						
Bruce A[3]	48.9%	**209**	202	(149)	**3,944**	3,988
Bruce B[3]	31.6%	**105**	108	163	**51**	377
ASTC Power Partnership	50.0%	**8**	110	40	**29**	41
Portlands Energy	50.0%	**36**	31	28	**335**	343
Other[4]	Various	**1**	1	18	**61**	57
Liquids Pipelines						
Grand Rapids	50.0%	**–**	–	–	**240**	70
		522	597	257	**5,598**	5,759

1 The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2014, TCPL had an ownership interest in TC PipeLines, LP of 28.3 per cent (2013 – 28.9 and 2012 – 33.3 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 14.2 per cent (2013 – 14.5 and 2012 – 16.7 per cent).

2 At December 31, 2014, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$117 million (2013 – US$118 million) due to the fair value assessment of assets at the time of acquisition.

3 At December 31, 2014, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $776 million (2013 – $820 million) due to the fair value assessment of assets at the time of acquisition.

4 In December 2012, TCPL acquired the remaining 40 per cent interest in CrossAlta to bring the Company's ownership interest to 100 per cent. The results reflect the Company's 60 per cent share of equity income up to that date.

Distributions received from equity investments for the year ended December 31, 2014 were $726 million (2013 – $725 million; 2012 – $436 million) of which $147 million (2013 – $120 million; 2012 – $60 million) were returns of capital and are included in Deferred Amounts and Other in the Consolidated Statement of Cash Flows. The undistributed earnings from equity investments as at December 31, 2014 were $551 million (2013 – $754 million; 2012 – $883 million).

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Income			
Revenues	**4,814**	4,989	3,860
Operating and Other Expenses	**(3,489)**	(3,536)	(3,090)
Net Income	**1,264**	1,390	717
Net Income attributable to TCPL	**522**	597	257

at December 31 (millions of Canadian dollars)	2014	2013
Balance Sheet		
Current assets	**1,412**	1,500
Non current assets	**12,260**	12,158
Current liabilities	**(1,067)**	(1,117)
Non current liabilities	**(3,255)**	(2,507)

9. RATE-REGULATED BUSINESSES

TCPL's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain Canadian liquids pipelines currently under development. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

The Canadian Mainline, NGTL System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

TCPL's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. 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. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

On November 28, 2014, the NEB released its decision on TCPL's 2015-2030 Tolls Application (the NEB 2014 Decision). The NEB 2014 Decision acknowledged that an off-ramp had been reached on the NEB 2013 Decision (discussed below) and approved fixed tolls for 2015 to 2020 as well as certain parameters for a toll setting methodology to 2030. Features of the settlement reached with shippers as approved in the NEB 2014 Decision include an ROE of 10.1 per cent on a deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TCPL contribution to reduce the revenue requirement. Toll stabilization is achieved through the continued use of deferral accounts, namely the Long Term Adjustment Account (LTAA) and the Bridging Amortization Account, to capture the surplus or the shortfall between the Company's revenues and cost of service for each year over the six-year fixed toll term of the NEB 2014 Decision. TCPL is required to file a compliance filing with the NEB in first quarter 2015 and a toll review for the 2018 to 2020 period prior to December 31, 2017.

In March 2013, TCPL received a decision from the NEB which set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others (the NEB 2013 Decision). The decision established an ROE of 11.5 per cent on a deemed common equity of 40 per cent and included mechanisms to achieve the fixed tolls through the use of a LTAA as well as the establishment of a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five-year term of the decision. In addition, the decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs. The NEB also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances occurred in 2013 when the TSA balance became positive. In December 2013, TCPL filed the 2015-2030 Tolls Application with the NEB that addressed tolls moving forward including tolls for 2014.

The Canadian Mainline's 2012 results reflect an ROE of 8.08 per cent on a deemed common equity of 40 per cent and excluded incentive earnings.

NGTL System

In November 2013, the NEB approved the NGTL System's 2013-2014 Revenue Requirement Settlement Application. This settlement is structured similar to the previous multi-year settlement with fixed annual operating, maintenance and administration (OM&A) costs and a 10.1 per cent ROE on a deemed common equity of 40 per cent. Any variance between fixed OM&A costs in the settlement and actual costs accrue to TCPL. The Settlement also establishes an increase in the composite depreciation rates to 3.05 per cent in 2013 and 3.12 per cent in 2014.

The NGTL System's 2012 results reflected a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixed certain annual OM&A costs. Any variances between actual costs and those agreed to in the settlement then in effect accrued to TCPL. All other costs were treated on a flow-through basis.

Energy East

Energy East is currently in the development stage, awaiting regulatory approval from the NEB. Tolls will be designed to provide for cost recovery including return of and on capital as approved by the NEB.

Other Canadian Pipelines

The Foothills operating model for 2012 through 2014 provides for recovery of all revenue requirement components on a flow-through basis. TQM operates under a model consisting of fixed and flow-through revenue requirement components for 2012 through 2016. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TCPL's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA 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. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective for all periods presented, beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future, but is not prohibited from filing for new rates if necessary.

ANR Storage Company rates were established pursuant to a settlement approved by the FERC in August 2012. ANR Storage Company is required to file a NGA Section 4 general rate case no later than July 1, 2016.

TC Offshore LLC, another ANR-related regulated entity, began operating under FERC approved tariff rates on November 1, 2012. TC Offshore LLC is required to file a cost and revenue study to justify its existing approved cost-based rates after its first three years of operation.

Great Lakes

Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes operated under a July 2010 FERC approved rate settlement through October 2013. Effective November 1, 2013, Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. The settlement provides for a moratorium between November 2013 and March 2015 during which Great Lakes and the settling parties are prohibited from taking certain actions under the NGA, including filing to adjust rates. Great Lakes is required to file for new rates to be effective no later than January 2018.

Other U.S. Pipelines

GTN and Bison are regulated by the FERC and operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. Both pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. GTN is required to file for new rates to be effective no later than January 2016.

Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011. Bison filed a cost and revenue study as required by FERC to justify its existing approved cost-based rates after its first three years of operations. This study was filed by Bison on April 10, 2014 and accepted by FERC on May 20, 2014. At this time Bison is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary.

Mexico Regulated Operations

TCPL's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. In 2014, TCPL began using RRA for all natural gas pipelines in Mexico. The rates were established based on CRE approved negotiated contracts.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian dollars)	2014	2013	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,001**	1,149	n/a
Operating and debt-service regulatory assets[2]	**4**	16	1
Pensions and other post retirement benefits[3]	**236**	190	n/a
Long Term Adjustment Account[4]	**–**	354	31
Other[5]	**72**	68	n/a
	1,313	1,777	
Less: Current portion included in Other Current Assets (Note 5)	**16**	42	
	1,297	1,735	
Regulatory Liabilities			
Foreign exchange on long-term debt[6]	**42**	84	1-15
Operating and debt-service regulatory liabilities[2]	**21**	5	1
ANR-related post-employment and retirement benefits other than pension[7]	**117**	104	n/a
Long Term Adjustment Account[4]	**64**	–	44
Other[5]	**49**	43	n/a
	293	236	
Less: Current portion included in Accounts Payable and Other (Note 13)	**30**	7	
	263	229	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 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 following calendar year. Pre-tax operating results in 2014 would have been $28 million higher (2013 – $76 million higher; 2012 – $50 million lower) had these amounts not been recorded as regulatory assets and liabilities.

3 These balances represent the regulatory offset to pension plan and other post retirement obligations to the extent the amounts are expected to be collected from customers in future rates. The balances are excluded from the rate base and do not earn a return on investment. Pre-tax operating results in 2014 would have been $46 million lower (2013 – $171 million higher; 2012 – $61 million lower) had these amounts not been recorded as regulatory assets and liabilities.

4 The LTAA was established in compliance with the NEB 2013 Decision which is comprised of amounts that were deferred and recoverable in future years. The TSA, also established in the NEB 2013 Decision, includes the variances between revenue and costs. A positive balance in the TSA was realized in 2013 and 2014 and, as specified in the NEB 2013 Decision and the NEB 2014 Decision, the TSA, net of incentive earnings, was combined with the LTAA on December 31, 2013 and 2014.

5 Pre-tax operating results in 2014 would have been $2 million higher (2013 – $2 million higher; 2012 – $66 million higher) had these amounts not been recorded as regulatory assets and liabilities.

6 Foreign exchange on long-term debt of the NGTL System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. 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 RRA, GAAP would have required the inclusion of these unrealized gains or losses in Net Income.

7 Under the terms of the settlement of ANR's last rate settlement, ANR will be required to make refunds to its customers, pursuant to a refund plan to be approved by FERC in a future rate proceeding, of those amounts in the postretirement benefit trust fund that have not been used to pay benefits to its employees. This regulatory liability represents the difference between the amount collected in rates and the amount of postretirement benefits expense. ANR can but is not required to file for new rates. Therefore, the settlement/recovery period is not determinable. Pre-tax operating results in 2014 would have been $13 million higher (2013 – $16 million higher; 2012 – $8 million higher) had these amounts not been recorded as regulatory assets and liabilities.

Allowance for Funds Used During Construction

The total amount of AFUDC included in the Consolidated Statement of Income was $95 million in 2014, $19 million in 2013 and $15 million in 2012.

10. GOODWILL

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

(millions of Canadian dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2013	2,635	823	3,458
Foreign exchange rate changes	181	57	238
Balance at December 31, 2013	2,816	880	3,696
Foreign exchange rate changes	**258**	**80**	**338**
Balance at December 31, 2014	**3,074**	**960**	**4,034**

11. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian dollars)	2014	2013
Capital projects under development	**1,286**	571
PPAs	**272**	324
Deferred income tax assets and charges (Note 16)	**177**	223
Loans and advances[1]	**167**	183
Fair value of derivative contracts (Note 23)	**93**	112
Employee post-retirement benefits (Note 22)	**14**	16
Other	**691**	524
	2,700	1,953

1 TransCanada held a note receivable from the seller of Ravenswood of $213 million (US$184 million) and $226 million (US$212 million) as at December 31, 2014 and at December 31, 2013, respectively which bears interest at 6.75 per cent and matures in 2040. The current portion included in Other Current Assets was $46 million (US$40 million) at December 31, 2014 and $43 million (US$40 million) at December 31, 2013.

The following amounts related to PPAs are included in Intangible and Other Assets:

at December 31 (millions of Canadian dollars)	2014 Cost	 Accumulated Amortization	 Net Book Value	2013 Cost	 Accumulated Amortization	 Net Book Value
Sheerness	**585**	**351**	**234**	585	312	273
Sundance A	**225**	**187**	**38**	225	174	51
	810	**538**	**272**	810	486	324

Amortization expense for these PPAs was $52 million for the year ended December 31, 2014 (2013 and 2012 – $52 million). The expected annual amortization expense for 2015 to 2017 is $52 million, and $39 million for 2018 and 2019.

12. NOTES PAYABLE

(millions of Canadian dollars)	2014 Outstanding December 31	 Weighted Average Interest Rate per Annum at December 31	2013 Outstanding December 31	 Weighted Average Interest Rate per Annum at December 31
Canadian dollars	**1,540**	**1.2%**	751	1.2%
U.S. dollars (2014 – US$800; 2013 – US$1,025)	**927**	**0.7%**	1,091	0.3%
	2,467		1,842	

Notes Payable consists of commercial paper issued by TCPL, TransCanada PipeLine USA Ltd. (TCPL USA), TransCanada American Investments Ltd. (TAIL), and TransCanada Keystone Pipeline, LP (TC Keystone) and drawings on credit facilities. The TC Keystone commercial paper program and facility were terminated in November 2013. The TAIL commercial paper program was initiated in November 2013, replacing the TCPL USA program which was terminated in April 2014.

Notes Payable also includes a US$170 million short-term loan, which was issued on October 1, 2014, by TC Pipelines LP.

At December 31, 2014, total committed revolving and demand credit facilities of $6.7 billion (2013 – $6.2 billion) were available. When drawn, interest on these lines of credit is charged at prime rates of

Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2014					year ended December 31		
					2014	**2013**	**2012**
Amount	**Unused Capacity**	**Borrower**	**For**	**Matures**	**Cost to maintain**		
					(millions of Canadian dollars)		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2019	6	4	4
US$1 billion	US$1 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL	November 2015	2	1	1
US$1 billion	US$1 billion	TAIL	Committed, syndicated, revolving, extendible TAIL credit facility, guaranteed by TCPL	November 2015	1	–	–
$1.4 billion	$0.6 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	–	–	–

13. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Trade payables	**1,624**	866
Fair value of derivative contracts (Note 23)	**749**	357
Dividends payable	**345**	328
Deferred Income Tax Liabilities (Note 16)	**4**	26
Regulatory Liabilities (Note 9)	**30**	7
Liabilities related to assets held for sale (Note 6)	**–**	5
Other	**143**	552
	2,895	2,141

14. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Employee post-retirement benefit (Note 22)	**444**	244
Fair value of derivative contracts (Note 23)	**411**	255
Asset retirement obligations	**98**	83
Guarantees (Note 26)	**15**	18
Other	**84**	56
	1,052	656

15. LONG-TERM DEBT

Outstanding loan amounts (millions of Canadian dollars)	Maturity Dates	2014 Outstanding December 31	2014 Interest Rate[1]	2013 Outstanding December 31	2013 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2015 to 2020	**749**	**10.9%**	874	10.9%
U.S. dollars (2014 and 2013 US$400)	2021	**464**	**9.9%**	425	9.9%
Medium-Term Notes					
Canadian dollars	2016 to 2041	**4,048**	**5.7%**	4,799	5.7%
Senior Unsecured Notes					
U.S. dollars (2014 – US$13,526; 2013 – US$12,276)	2015 to 2043	**15,655**	**5.0%**	13,027	5.0%
		20,916		19,125	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars[2]	2016 to 2024	**325**	**11.5%**	378	11.5%
U.S. dollars (2014 and 2013 – US$200)	2023	**232**	**7.9%**	213	7.9%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. dollars (2014 and 2013 – US$33)	2026	**38**	**7.5%**	34	7.5%
		1,099		1,129	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$432)	2021 to 2025	**502**	**8.9%**	459	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$325)	2015 to 2035	**377**	**5.5%**	346	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2014 – US$330; 2013 – US$380)	2017	**383**	**1.4%**	404	1.4%
Unsecured Term Loan Facility					
U.S. dollars (2014 – US$500; 2013 – US$500)	2015 to 2018	**580**	**1.4%**	532	1.4%
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$350)	2021	**405**	**4.7%**	372	4.7%
		1,368		1,308	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2014 – US$316; 2013 – US$335)	2018 to 2030	**367**	**7.8%**	356	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2014 – US$20; 2013 – US$24)	2017	**23**	**4.0%**	25	4.0%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2014 – US$90; 2013 – US$110)	2018	**105**	**6.1%**	117	6.1%
		24,757		22,865	
Less: Current Portion of Long-Term Debt		**1,797**		973	
		22,960		21,892	

1 Interest rates are the effective interest rates except for those pertaining to Long-Term Debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Debentures issued by 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 in 2014 or 2013.

3 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:

(millions of Canadian dollars)	2015	2016	2017	2018	2019
Principal repayments on Long-Term Debt	1,797	2,225	846	1,766	1,007

Long-Term Debt Issued

The Company issued Long-Term Debt over the last three years ended December 31 as follows:

(millions of Canadian dollars, unless otherwise noted)

Company	Issue date	Type	Maturity date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US 625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US 625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US 500	Floating
	July 2013	Medium-Term Notes	July 2023	450	3.69%
	July 2013	Medium-Term Notes	November 2041	300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US 750	0.75%
	August 2012	Senior Unsecured Notes	August 2022	US 1,000	2.50%
	March 2012	Senior Unsecured Notes	March 2015	US 500	0.88%
TC PIPELINES, LP					
	July 2013	Unsecured Term Loan Facility	July 2018	US 500	Floating

Long-Term Debt Retired

The Company retired Long-Term Debt over the last three years ended December 31 as follows:

(millions of Canadian dollars, unless otherwise noted)

Company	Retirement date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	June 2014	Debentures	125	11.10%
	February 2014	Medium-Term Notes	300	5.05%
	January 2014	Medium-Term Notes	450	5.65%
	August 2013	Senior Unsecured Notes	US 500	5.05%
	June 2013	Senior Unsecured Notes	US 350	4.00%
	May 2012	Senior Unsecured Notes	US 200	8.63%
NOVA GAS TRANSMISSION LTD.				
	June 2014	Debentures	53	11.20%
	December 2012	Debentures	US 175	8.50%

Interest Expense

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Interest on Long-Term Debt	**1,317**	1,216	1,190
Interest on Junior Subordinated Notes (Note 17)	**70**	65	63
Interest on short-term debt	**52**	73	77
Capitalized interest	**(259)**	(287)	(300)
Amortization and other financial charges[1]	**55**	(21)	7
	1,235	1,046	1,037

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $1,160 million in 2014 (2013 – $1,047 million; 2012 – $1,027 million) on Long-Term Debt and Junior Subordinated Notes, net of interest capitalized.

16. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Current			
Canada	**104**	27	171
Foreign	**42**	16	14
	146	43	185
Deferred			
Canada	**307**	239	60
Foreign	**377**	323	216
	684	562	276
Income Tax Expense	**830**	605	461

Geographic Components of Income

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Canada	**1,146**	1,201	821
Foreign	**1,678**	1,298	1,096
Income before Income Taxes	**2,824**	2,499	1,917

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Income before Income Taxes	**2,824**	2,499	1,917
Federal and provincial statutory tax rate	**25.0%**	25.0%	25.0%
Expected income tax expense	**706**	625	479
Income tax differential related to regulated operations	**129**	(13)	41
Higher/(lower) effective foreign tax rates	**25**	33	(12)
Income from equity investments and non-controlling interests	**(38)**	(28)	(27)
Tax legislation change	**–**	(25)	–
Other	**8**	13	(20)
Actual Income Tax Expense	**830**	605	461

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian dollars)	2014	2013
Deferred Income Tax Assets		
Operating loss carryforwards	**1,266**	826
Deferred amounts	**215**	223
Unrealized foreign exchange losses on long-term debt	**140**	–
Financial Instruments	**104**	–
Other	**245**	124
	1,970	1,173
Less: Valuation allowance[1]	**125**	–
	1,845	1,173
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**5,548**	4,245
Equity investments	**648**	682
Taxes on future revenue requirement	**253**	291
Unrealized foreign exchange gains on long-term debt	**–**	35
Other	**71**	170
	6,520	5,423
Net Deferred Income Tax Liabilities	**4,675**	4,250

1 A valuation allowance was recorded in 2014 as the Company believes that it is more likely than not that the tax benefit related to the unrealized foreign exchange losses on the long term debt will not be realized in the future.

The above deferred tax amounts have been classified in the Consolidated Balance Sheet as follows:

at December 31 (millions of Canadian dollars)	2014	2013
Deferred Income Tax Assets		
Other Current Assets (Note 5)	**427**	117
Intangible and Other Assets (Note 11)	**177**	223
	604	340
Deferred Income Tax Liabilities		
Accounts Payable and Other (Note 13)	**4**	26
Deferred Income Tax Liabilities	**5,275**	4,564
	5,279	4,590
Net Deferred Income Tax Liabilities	**4,675**	4,250

At December 31, 2014, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,131 million (2013 – $1,026 million) for federal and provincial purposes in Canada, which expire from 2015 to 2034.

At December 31, 2014, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,267 million (2013 – US$1,432 million) for federal purposes in the U.S., which expire from 2028 to 2034.

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. Deferred income tax liabilities would have increased at December 31, 2014 by approximately $236 million (2013 – $182 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $109 million, net of refunds, were made in 2014 (2013 – payments, net of refunds, of $206 million; 2012 – refunds, net of payments made, of $175 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian dollars)	2014	2013	2012
Unrecognized tax benefits at beginning of year	**19**	45	48
Gross increases – tax positions in prior years	**2**	3	2
Gross decreases – tax positions in prior years	**(8)**	(28)	(6)
Gross increases – tax positions in current year	**1**	2	9
Lapses of statute of limitations	**(1)**	(3)	(8)
Unrecognized tax benefits at end of year	**13**	19	45

TCPL recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian Federal tax legislation in June 2013.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TCPL does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TCPL and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2009. Substantially all material U.S. federal income tax matters have been concluded for years through 2007 and U.S. state and local income tax matters through 2007.

TCPL's practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Income Tax Expense for the year ended December 31, 2014 reflects nil for Interest Expense and nil for penalties (2013 – nil for Interest Expense and nil for penalties; 2012 – $2 million reversal for Interest Expense and nil for penalties). At December 31, 2014, the Company had $5 million accrued for Interest Expense and nil accrued for penalties (December 31, 2013 – $5 million accrued for Interest Expense and nil accrued for penalties).

17. JUNIOR SUBORDINATED NOTES

		2014		2013	
Outstanding loan amount (millions of Canadian dollars)	**Maturity Date**	**Outstanding December 31**	**Effective Interest Rate**	**Outstanding December 31**	**Effective Interest Rate**
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2014 and 2013 – US$1,000)	2067	**1,160**	**6.5%**	1,063	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per annum until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default or permitting acceleration of payment under the terms of the Junior Subordinated Notes, however, the Company would be prohibited from paying dividends during any such 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 other 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.

18. NON-CONTROLLING INTERESTS

The Company's Non-Controlling Interests included in the Consolidated Balance Sheet were as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Non-controlling interest in TC PipeLines, LP	**1,479**	1,323
Non-controlling interest in Portland	**104**	94
	1,583	1,417

The Company's Non-Controlling Interests included in the Consolidated Statement of Income were as follows:

year ended December 31 (millions of Canadian dollars)	**2014**	2013	2012
Non-controlling interest in TC PipeLines, LP	**136**	93	91
Non-controlling interest in Portland	**15**	12	5
	151	105	96

During 2014, the non-controlling interest in TC PipeLines, LP increased from 71.1 per cent to 71.7 per cent due to the issuance of common units in TC PipeLines, LP to non-controlling interests. The non-controlling interest in TC PipeLines, LP from May 2013 to August 2014 was 71.1 per cent and from May 2011 to May 2013 was 66.7 per cent.

The non-controlling interest in Portland as at December 31, 2014 represented the 38.3 per cent interest not owned by TCPL (2013 and 2012 – 38.3 per cent).

In 2014, TCPL received fees of $3 million from TC PipeLines, LP (2013 and 2012 – $3 million) and $8 million from Portland (2013 and 2012 – $7 million) for services provided.

19. COMMON SHARES

	Number of Shares	**Amount**
	(thousands)	(millions of Canadian dollars)
Outstanding at January 1, 2012	731,872	14,037
Issuance of common shares for cash	6,509	269
Outstanding at December 31, 2012	738,381	14,306
Issuance of common shares for cash	18,733	899
Outstanding at December 31, 2013	757,114	15,205
Issuance of common shares for cash	**22,365**	**1,115**
Outstanding at December 31, 2014	**779,479**	**16,320**

Common Shares Issued and Outstanding

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

Restriction on Dividends

Certain terms of the Company's debt instruments can limit the amount of dividends the Company can pay on preferred and common shares. At December 31, 2014 these terms limit the company from paying dividends in excess of $8.7 billion (2013 – $1.3 billion; 2012 – $7.0 billion). Under the agreements, TCPL can adjust this limit throughout the year if required, at is sole discretion, without incurring significant costs.

Stock Option Plan

Certain key employees, including officers, are granted stock options from TransCanada to purchase common shares at the market price on the grant date. Stock options vest equally over three years, beginning on the first anniversary of the grant date, and expire after seven years. TCPL records the compensation expense associated with these stock options.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	2014	2013	2012
Expected life (years)	**6.0**	6.0	5.9
Interest rate	**1.8%**	1.7%	1.6%
Volatility[1]	**17%**	18%	19%
Dividend yield	**3.8%**	3.7%	4.2%
Forfeiture rate	**5%**	15%	15%

1 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional Paid-In Capital, was $9 million in 2014 (2013 – $6 million; 2012 – $5 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian dollars, unless noted otherwise)	2014	2013	2012
Total intrinsic value of options exercised	**$68**	$25	$18
Fair value of options that have vested	**$113**	$65	$49
Total options vested	**2.0 million**	1.3 million	1.0 million

As at December 31, 2014, the aggregate intrinsic value of the total options exercisable was $85 million and the total intrinsic value of options outstanding was $118 million.

20. PREFERRED SHARES

In March 2014, TCPL redeemed all of the 4 million outstanding Series Y preferred shares at a redemption price of $50 per share for a gross payment of $200 million.

In October 2013, TCPL redeemed all of the 4 million outstanding Series U preferred shares at a redemption price of $50 per share for a gross payment of $200 million.

21. OTHER COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI including Non-Controlling Interests and the related tax effects are as follows:

year ended December 31, 2014 (millions of Canadian dollars)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains on net investments in foreign operations	**462**	**55**	**517**
Change in fair value of net investment hedges	**(373)**	**97**	**(276)**
Change in fair value of cash flow hedges	**(118)**	**49**	**(69)**
Reclassification to Net Income of gains and losses on cash flow hedges	**(95)**	**40**	**(55)**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(146)**	**44**	**(102)**
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**25**	**(7)**	**18**
Other comprehensive loss on Equity Investments	**(272)**	**68**	**(204)**
Other comprehensive loss	**(517)**	**346**	**(171)**

year ended December 31, 2013 (millions of Canadian dollars)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains on net investments in foreign operations	269	114	383
Change in fair value of net investment hedges	(323)	84	(239)
Change in fair value of cash flow hedges	121	(50)	71
Reclassification to Net Income of gains and losses on cash flow hedges	60	(19)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	96	(29)	67
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	34	(11)	23
Other comprehensive income on Equity Investments	313	(79)	234
Other comprehensive income	570	10	580

year ended December 31, 2012 (millions of Canadian dollars)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation losses on net investments in foreign operations	(97)	(32)	(129)
Change in fair value of net investment hedges	59	(15)	44
Change in fair value of cash flow hedges	61	(13)	48
Reclassification to Net Income of gains and losses on cash flow hedges	219	(81)	138
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(104)	31	(73)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	22	–	22
Other comprehensive loss on Equity Investments	(93)	23	(70)
Other comprehensive income/(loss)	67	(87)	(20)

The changes in AOCI by component is as follows:

	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total[1]
AOCI Balance at January 1, 2012	(643)	(302)	(236)	(268)	(1,449)
Other comprehensive (loss)/income before reclassifications[2]	(64)	48	(73)	(67)	(156)
Amounts reclassified from Accumulated Other Comprehensive Loss	–	138	22	(3)	157
Net current period other comprehensive (loss)/income	(64)	186	(51)	(70)	1
AOCI Balance at December 31, 2012	(707)	(116)	(287)	(338)	(1,448)
Other comprehensive income before reclassifications[2]	78	71	67	219	435
Amounts reclassified from Accumulated Other Comprehensive Loss	–	41	23	15	79
Net current period other comprehensive income	78	112	90	234	514
AOCI Balance at December 31, 2013	(629)	(4)	(197)	(104)	(934)
Other comprehensive income/(loss) before reclassifications[2]	**111**	**(69)**	**(102)**	**(206)**	**(266)**
Amounts reclassified from Accumulated Other Comprehensive Loss[3]	**–**	**(55)**	**18**	**2**	**(35)**
Net current period other comprehensive income/(loss)	**111**	**(124)**	**(84)**	**(204)**	**(301)**
AOCI Balance at December 31, 2014	**(518)**	**(128)**	**(281)**	**(308)**	**(1,235)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 OCI before reclassifications on currency translation adjustments is net of non-controlling interest gains of $130 million in 2014 (2013 – $66 million gains; 2012 – $21 million losses).

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $95 million ($55 million, net of tax) at December 31, 2014. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated Statement of Income are as follows:

year ended December 31 (millions of Canadian dollars)	**Amounts reclassified from accumulated other comprehensive loss**[1] **2014**	**2013**	**2012**	**Affected line item in the consolidated statement of income**
Cash flow hedges				
Power and Natural Gas	**111**	(44)	(201)	Revenue (Energy)
Interest	**(16)**	(16)	(18)	Interest Expense
	95	(60)	(219)	Total before tax
	(40)	19	81	Income Tax Expense
	55	(41)	(138)	Net of tax
Pension and OPEB plan adjustments				
Amortization of actuarial loss and past service cost[2]	**(25)**	(34)	(22)	[2]
	7	11	–	Income Tax Expense
	(18)	(23)	(22)	Net of tax
Equity Investments				
Equity Income	**(2)**	(20)	5	Income from Equity Investments
	–	5	(2)	Income Tax Expense
	(2)	(15)	3	Net of tax

1 All amounts in parentheses indicate expenses to the Consolidated Statement of Income.

2 These Accumulated Other Comprehensive Loss components are included in the computation of net benefit cost. Refer to Note 22 for additional detail.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years (2013 and 2012 – nine years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and 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 12 years at December 31, 2014 (2013 – 11 years; 2012 – 12 years). In 2014, the Company expensed $37 million (2013 – $29 million; 2012 – $24 million) for the savings plan and DC Plans.

Total cash payments for employee post-retirement benefits, consisting of cash contributed by the Company were as follows:

year ended December 31 (millions of Canadian dollars)	**2014**	**2013**	**2012**
DB Plans	**73**	79	83
Other post-retirement benefit plans	**6**	6	7
Savings and DC Plans	**37**	29	24
	116	114	114

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, in 2014 the Company provided a $47 million letter of credit to the Canadian DB Plan (2013 – $59 million; 2012 – $48 million), resulting in a total of $181 million provided to the Canadian DB Plan under letters of credit at December 31, 2014.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2014 and the next required valuation will be as at January 1, 2015.

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**2,224**	2,142	**191**	186
Service cost	**85**	84	**2**	2
Interest cost	**113**	96	**10**	7
Employee contributions	**4**	4	**–**	–
Benefits paid	**(102)**	(83)	**(7)**	(7)
Actuarial loss/(gain)	**302**	(39)	**14**	(2)
Foreign exchange rate changes	**32**	20	**6**	5
Benefit obligation – end of year	**2,658**	2,224	**216**	191
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,152**	1,825	**35**	32
Actual return on plan assets	**246**	313	**2**	2
Employer contributions[2]	**73**	79	**6**	6
Employee contributions	**4**	4	**–**	–
Benefits paid	**(102)**	(83)	**(7)**	(7)
Foreign exchange rate changes	**25**	14	**3**	2
Plan assets at fair value – end of year	**2,398**	2,152	**39**	35
Funded Status – Plan Deficit	**(260)**	(72)	**(177)**	(156)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes $181 million in letters of credit provided to the Canadian DB Plans for funding purposes (2013 – $134 million).

The amounts recognized in the Company's Balance Sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31 (millions of Canadian dollars)	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	2014	**2013**	**2014**	**2013**
Intangible and Other Assets (Note 11)	**–**	–	**14**	16
Accounts Payable and Other (Note 13)	**–**	–	**(7)**	–
Other Long-Term Liabilities (Note 14)	**(260)**	(72)	**(184)**	(172)
	(260)	(72)	**(177)**	(156)

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

at December 31 (millions of Canadian dollars)	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	2014	**2013**	**2014**	**2013**
Projected benefit obligation[1]	**(2,658)**	(2,224)	**(191)**	(172)
Plan assets at fair value	**2,398**	2,152	**–**	–
Funded Status – Deficit	**(260)**	(72)	**(191)**	(172)

1 The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The accumulated benefit obligation for all DB pension plans at December 31, 2014 is $2,437 million (2013 – $2,039 million).

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Accumulated benefit obligation	**(2,437)**	(2,039)
Plan assets at fair value	**2,398**	2,152
Funded Status – (Deficit)/Surplus	**(39)**	113

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

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Accumulated benefit obligation	**(715)**	(569)
Plan assets at fair value	**597**	537
Funded Status – Deficit	**(118)**	(32)

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

Asset Category

	Percentage of Plan Assets		Target Allocations[1]
at December 31	**2014**	**2013**	**2014**
Debt securities	**31%**	31%	**25% to 35%**
Equity securities	**69%**	69%	**50% to 70%**
Alternatives	**–**	–	**5% to 15%**
	100%	100%	

1 Target allocations were revised in November 2013 and the investment mix is being adjusted over time accordingly.

Debt and equity securities include the Company's debt and common shares as follows:

			Percentage of Plan Assets	
at December 31 (millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Debt securities	**1**	2	**0.1%**	0.1%
Equity securities	**1**	2	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. For further information on the fair value hierarchy, refer to Note 23.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian dollars)	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Asset Category										
Cash and Cash Equivalents	20	17	–	–	–	–	20	17	1%	1%
Equity Securities:										
Canadian	361	474	142	170	–	–	503	644	21%	29%
U.S.	516	423	35	37	–	–	551	460	23%	21%
International	218	36	147	330	–	–	365	366	15%	17%
Global	–	–	141	14	–	–	141	14	6%	1%
Emerging	7	–	80	–	–	–	87	–	3%	–
Fixed Income Securities:										
Canadian Bonds:										
Federal	–	–	218	190	–	–	218	190	9%	9%
Provincial	–	–	180	154	–	–	180	154	7%	7%
Municipal	–	–	7	6	–	–	7	6	–	–
Corporate	–	–	76	77	–	–	76	77	3%	3%
U.S. Bonds:										
State	–	–	47	33	–	–	47	33	2%	2%
Corporate	–	–	59	48	–	–	59	48	2%	2%
International:										
Corporate	–	–	14	20	–	–	14	20	1%	1%
Mortgage Backed	–	–	39	26	–	–	39	26	2%	1%
Other Investments:										
Private Equity Funds	–	–	–	–	13	18	13	18	–	1%
Funds held on deposit	117	114			–	–	117	114	5%	5%
	1,239	1,064	1,185	1,105	13	18	2,437	2,187	100%	100%

The following table presents the net change in the Level III fair value category:

(millions of Canadian dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2012	19
Purchases and Sales	(4)
Realized and unrealized gains	3
Balance at December 31, 2013	18
Purchases and sales	**(7)**
Realized and unrealized gains	**2**
Balance at December 31, 2014	**13**

The Company's expected funding contributions in 2015 are approximately $70 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $36 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $35 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

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

(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits
2015	102	8
2016	108	8
2017	114	9
2018	120	9
2019	127	10
2020 to 2024	728	51

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2014. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

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

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2014**	**2013**	**2014**	**2013**
Discount rate	**4.15%**	4.95%	**4.20%**	5.00%
Rate of compensation increase	**3.15%**	3.15%	**–**	–

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Discount rate	**4.95%**	4.35%	5.05%	**5.00%**	4.35%	5.10%
Expected long-term rate of return on plan assets	**6.90%**	6.70%	6.70%	**4.60%**	4.60%	6.40%
Rate of compensation increase	**3.15%**	3.15%	3.15%	**–**	–	–

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 7.5 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015 measurement purposes. The rate was assumed to decrease gradually to five per cent by

2020 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	14	(12)

The Company's net benefit cost is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian dollars)	**2014**	2013	2012	**2014**	2013	2012
Service cost	**85**	84	66	**2**	2	2
Interest cost	**113**	96	94	**10**	7	8
Expected return on plan assets	**(139)**	(120)	(113)	**(2)**	(2)	(2)
Amortization of actuarial loss	**21**	30	18	**2**	2	1
Amortization of past service cost	**2**	2	2	**–**	–	1
Amortization of regulatory asset	**18**	30	19	**1**	1	1
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net Benefit Cost Recognized	**100**	122	86	**15**	12	13

Pre-tax amounts recognized in AOCI were as follows:

at December 31	2014		2013		2012	
(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**354**	**40**	236	32	362	33
Prior service cost	**2**	**1**	3	1	5	2
	356	**41**	239	33	367	35

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost in 2015 are $27 million and $2 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost in 2015 is $2 million and nil, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31	2014		2013		2012	
(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Amortization of net loss from AOCI to OCI	**(21)**	**(2)**	(30)	(2)	(19)	(1)
Amortization of prior service costs from AOCI to OCI	**(2)**	**–**	(2)	–	(2)	–
Funded status adjustment	**137**	**9**	(96)	–	99	5
	114	**7**	(128)	(2)	78	4

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TCPL has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit 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.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may 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 strategy to assist in managing the exposure to market risk that results from these activities. These derivative contracts may 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. TCPL enters into foreign exchange and commodity forwards and futures to manage 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 manage the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements that 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 manage 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 and natural gas. A number of strategies are used to manage these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio.
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or through purchased contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative 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.

Natural Gas Storage Commodity Price Risk

TCPL manages its exposure to seasonal natural gas price spreads in its non-regulated 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. TCPL 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 natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

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 interest rates.

A portion of TCPL's earnings from its Natural Gas Pipelines, Liquids Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TCPL's net income. As the Company's U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases; some of this foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that may arise on some of the Company's regulated assets, in which case certain of the realized gains and losses on these derivatives would be deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers.

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

Net Investment in Foreign Operations

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

U.S. Dollar-Denominated Debt Designated as a Net Investment Hedge

at December 31 (millions of Canadian dollars, unless noted otherwise)	**2014**	**2013**
Carrying value	**17,000 (US 14,700)**	14,200 (US 13,400)
Fair value	**19,000 (US 16,400)**	16,000 (US 15,000)

Derivatives Designated as a Net Investment Hedge

	2014		**2013**	
at December 31 (millions of Canadian dollars, unless noted otherwise)	**Fair Value[1]**	**Notional or Principal Amount**	**Fair Value[1]**	**Notional or Principal Amount**
U.S. dollar cross-currency interest rate swaps (maturing 2015 to 2019)[2]	**(431)**	**US 2,900**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2015)	**(28)**	**US 1,400**	(11)	US 850
	(459)	**US 4,300**	(212)	US 4,650

1 Fair values approximate carrying values.

2 In 2014, net realized gains of $21 million (2013 – gains of $29 million) related to the interest component of cross-currency swap settlements are included in Interest Expense.

The balance sheet classification of the fair value of derivatives used to hedge the Company's net investment in foreign operations is as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Other Current Assets (Note 5)	**5**	5
Intangible and Other Assets (Note 11)	**1**	–
Accounts Payable and Other (Note 13)	**(155)**	(50)
Other Long-Term Liabilities (Note 14)	**(310)**	(167)
	(459)	(212)

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 the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- Setting limits on the amount TCPL can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when needed and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TCPL's maximum counterparty credit exposure with respect to financial instruments at December 31, 2014, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2014, there were no significant amounts past due or impaired, and there were no significant credit losses during the year. The Company had a credit risk concentration due from a counterparty of $258 million (US$222 million) and $240 million (US$225 million) at December 31, 2014 and 2013, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TCPL has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Financial Instruments

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's normal purchase and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Fair Value of Non-Derivative Financial Instruments

The fair value of the Company's notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Certain non-derivative financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Due from Affiliates, Intangible and Other Assets, Notes Payable, Accounts Payable and Other, Due to Affiliates, Accrued Interest and Other Long-Term Liabilities have carrying amounts that approximates their fair value due to the nature of the item or the short time to maturity and would be classified in Level II of the fair value hierarchy.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts equal fair value, and would be classified in Level II of the fair value hierarchy:

	2014		2013	
at December 31 (millions of Canadian dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Notes receivable and other[1]	**213**	**263**	226	269
Available for sale assets[2]	**62**	**62**	47	47
Current and Long-Term Debt[3,4] (Note 15)	**(24,757)**	**(28,713)**	(22,865)	(26,134)
Junior Subordinated Notes (Note 17)	**(1,160)**	**(1,157)**	(1,063)	(1,093)
	(25,642)	**(29,545)**	(23,655)	(26,911)

1 Notes receivable are included in Other Current Assets and Intangible and Other Assets on the Consolidated Balance Sheet.

2 Available for sale assets are included in Intangible and Other Assets on the Consolidated Balance Sheet.

3 Long-Term Debt is recorded at amortized cost, except for US$400 million (2013 – US$200 million) that is attributed to hedged risk and recorded at fair value.

4 Consolidated Net Income in 2014 included losses of $3 million (2013 – losses of $5 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$400 million of Long-Term Debt at December 31, 2014 (2013 – US$200 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives have been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives and available for sale assets has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Other Current Assets (Note 5)	**409**	395
Intangible and Other Assets (Note 11)	**93**	112
Accounts Payable and Other (Note 13)	**(749)**	(357)
Other Long-Term Liabilities (Note 14)	**(411)**	(255)
	(658)	(105)

2014 Derivative Instruments Summary

The following summary does not include hedges of the net investment in foreign operations.

(millions of Canadian dollars, unless noted otherwise)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$362**	**$69**	**$1**	**$4**
Liabilities	**($391)**	**($103)**	**($32)**	**($4)**
Notional Values				
Volumes[3]				
Purchases	**42,097**	**60**	**–**	**–**
Sales	**35,452**	**38**	**–**	**–**
U.S. dollars	**–**	**–**	**US 1,374**	**US 100**
Net unrealized losses in the year[4]	**($5)**	**($35)**	**($20)**	**$–**
Net realized (losses)/gains in the year[4]	**($39)**	**$11**	**($28)**	**$–**
Maturity dates	**2015-2019**	**2015-2020**	**2015**	**2015-2016**
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	**$57**	**$–**	**$–**	**$3**
Liabilities	**($163)**	**$–**	**$–**	**($2)**
Notional Values				
Volumes[3]				
Purchases	**11,120**	**–**	**–**	**–**
Sales	**3,977**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**–**	**US 550**
Net realized gains in the year[4]	**$130**	**$–**	**$–**	**$4**
Maturity dates	**2015-2019**	**–**	**–**	**2015-2018**

1 The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

2 Fair value equals carrying value.

3 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Energy Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $3 million and a notional amount of US$400 million. In 2014, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2014, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2014, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

2013 Derivative Instruments Summary

The following summary does not include hedges of the net investment in foreign operations.

(millions of Canadian dollars, unless noted otherwise)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$265	$73	$–	$8
Liabilities	($280)	($72)	($12)	($7)
Notional Values				
Volumes[3]				
Purchases	29,301	88	–	–
Sales	28,534	60	–	–
Canadian dollars	–	–	–	400
U.S. dollars	–	–	US 1,015	US 100
Net unrealized gains/(losses) in the year[4]	$19	$17	($10)	$–
Net realized losses in the year[4]	($49)	($13)	($9)	$–
Maturity dates	2014-2017	2014-2016	2014	2014-2016
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	$150	$–	$–	$6
Liabilities	($22)	$–	($1)	($1)
Notional Values				
Volumes[3]				
Purchases	9,758	–	–	–
Sales	6,906	–	–	–
U.S. dollars	–	–	US 16	US 350
Net realized (losses)/gains in the year[4]	($19)	($2)	$–	$5
Maturity dates	2014-2018	–	2014	2015-2018

1 The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

2 Fair value equals carrying value.

3 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Energy Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $5 million and a notional amount of US$200 million. In 2013, net realized gains on fair value hedges were $6 million and were included in Interest Expense. In 2013, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2013, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in Cash Flow Hedging Relationships

The following table presents the components of OCI (Note 21) related to derivatives in cash flow hedging relationships:

year ended December 31 (millions of Canadian dollars, pre-tax)	**2014**	**2013**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Power	**(126)**	117
Natural Gas	**(2)**	(1)
Foreign Exchange	**10**	5
	(118)	121
Reclassification of (losses)/gains on derivative instruments from AOCI to Net Income (effective portion)[1]		
Power[2]	**(114)**	40
Natural Gas[2]	**3**	4
Interest[3]	**16**	16
	(95)	60
(Losses)/gains on derivative instruments recognized in Net Income (ineffective portion)		
Power	**(13)**	8
	(13)	8

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

2 Reported within Energy Revenues on the Consolidated Statement of Income.

3 Reported within Interest Expense on the Consolidated Statement of Income.

Offsetting of Derivative Instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TCPL has no master netting agreements, however, similar contracts are entered into containing rights of offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2014 (millions of Canadian dollars)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative – Asset			
Power	**419**	**(330)**	**89**
Natural gas	**69**	**(57)**	**12**
Foreign exchange	**7**	**(7)**	**–**
Interest	**7**	**(1)**	**6**
	502	**(395)**	**107**
Derivative – Liability			
Power	**(554)**	**330**	**(224)**
Natural gas	**(103)**	**57**	**(46)**
Foreign exchange	**(497)**	**7**	**(490)**
Interest	**(6)**	**1**	**(5)**
	(1,160)	**395**	**(765)**

1 Amounts available for offset do not include cash collateral pledged or received.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2013:

at December 31, 2013 (millions of Canadian dollars)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset**[1]	**Net amounts**
Derivative – Asset			
Power	415	(277)	138
Natural gas	73	(61)	12
Foreign exchange	5	(5)	–
Interest	14	(2)	12
	507	(345)	162
Derivative – Liability			
Power	(302)	277	(25)
Natural gas	(72)	61	(11)
Foreign exchange	(230)	5	(225)
Interest	(8)	2	(6)
	(612)	345	(267)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to all financial arrangements, including the derivative instruments presented above as at December 31, 2014, the Company had provided cash collateral of $459 million (2013 – $67 million) and letters of credit of $26 million (2013 – $85 million) to its counterparties. The Company held $1 million (2013 – $11 million) in cash collateral and $1 million (2013 – $32 million) in letters of credit from counterparties on asset exposures at December 31, 2014.

Credit Risk Related Contingent Features of Derivative Instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade.

Based on contracts in place and market prices at December 31, 2014, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $15 million (2013 – $16 million), for which the Company has provided collateral in the normal course of business of nil (2013 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2014, the Company would have been required to provide additional collateral of $15 million (2013 – $16 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and power and natural gas commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivatives fair value. This category includes long-dated commodity transactions in certain markets where liquidity is low and inputs may include long-term broker quotes. Long-term electricity prices may also be estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices might be estimated on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas, small number of transactions in markets with lower liquidity are expected to or may result in a lower fair value measurement of contracts included in Level III. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2014, are categorized as follows:

at December 31, 2014 (millions of Canadian dollars, pre-tax)	**Quoted prices in active markets Level I[1]**	**Significant other observable inputs Level II[1]**	**Significant unobservable inputs Level III[1]**	**Total**
Derivative Instrument Assets:				
Power commodity contracts	**–**	**417**	**2**	**419**
Natural gas commodity contracts	**40**	**24**	**5**	**69**
Foreign exchange contracts	**–**	**7**	**–**	**7**
Interest rate contracts	**–**	**7**	**–**	**7**
Derivative Instrument Liabilities:				
Power commodity contracts	**–**	**(551)**	**(3)**	**(554)**
Natural gas commodity contracts	**(86)**	**(17)**	**–**	**(103)**
Foreign exchange contracts	**–**	**(497)**	**–**	**(497)**
Interest rate contracts	**–**	**(6)**	**–**	**(6)**
Non-Derivative Financial Instruments:				
Available for sale assets	**–**	**62**	**–**	**62**
	(46)	**(554)**	**4**	**(596)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2014.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2013, are categorized as follows:

at December 31, 2013 (millions of Canadian dollars, pre-tax)	**Quoted prices in active markets Level I[1]**	**Significant other observable inputs Level II[1]**	**Significant unobservable inputs Level III[1]**	**Total**
Derivative Instrument Assets:				
Power commodity contracts	–	411	4	415
Natural gas commodity contracts	48	25	–	73
Foreign exchange contracts	–	5	–	5
Interest rate contracts	–	14	–	14
Derivative Instrument Liabilities:				
Power commodity contracts	–	(299)	(3)	(302)
Natural gas commodity contracts	(50)	(22)	–	(72)
Foreign exchange contracts	–	(230)	–	(230)
Interest rate contracts	–	(8)	–	(8)
Non-Derivative Financial Instruments:				
Available for sale assets	–	47	–	47
	(2)	(57)	1	(58)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2013.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(millions of Canadian dollars, pre-tax)	2014	2013
Balance at beginning of year	**1**	(2)
Transfers out of Level III	**–**	(2)
Total gains/(losses) included in Net Income	**3**	(1)
Total gains included in OCI	**–**	6
Balance at end of year[1]	**4**	1

1 Energy Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2014 of $3 million (2013 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $1 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2014.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
(Increase)/decrease in Accounts Receivable	**(205)**	(60)	50
(Increase)/decrease in Inventories	**(27)**	(30)	27
(Increase)/decrease in Other Current Assets	**(386)**	40	64
Increase/(decrease) in Accounts Payable and Other	**393**	(291)	146
Increase in Accrued Interest	**36**	7	–
(Increase)/Decrease in Operating Working Capital	**(189)**	(334)	287

25. ACQUISITIONS AND DISPOSITIONS

Energy

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, TCPL completed the acquisition of three Ontario solar facilities for $181 million in September 2014 and acquired a fourth facility for $60 million in December 2014. In 2013, TCPL completed the acquisition of four solar facilities for $216 million. TCPL's total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb

On April 15, 2014, TCPL sold Cancarb Limited and its related power generation for aggregate gross proceeds of $190 million. Please refer to Note 6 for further information on the sale.

CrossAlta
In December 2012, TCPL purchased BP's 40 per cent interest in the assets of the Crossfield Gas Storage facility and BP's interest in CrossAlta Gas Storage & Services Ltd. (collectively CrossAlta) for $214 million in cash, net of cash acquired, resulting in the Company owning and operating 100 per cent of these operations.

The Company measured the assets and liabilities acquired at fair value and the transaction resulted in no goodwill. Upon completion of the acquisition, TCPL began consolidating CrossAlta. Prior to the acquisition, TCPL applied equity accounting to its 60 per cent ownership interest in CrossAlta.

Natural Gas Pipelines

TC PipeLines, LP
On October 1, 2014, TCPL completed the sale of its remaining 30 per cent interest in Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$215 million.

In July 2013, TCPL completed the sale of a 45 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million of long-term debt for 45 per cent of GTN LLC debt outstanding, plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million and net proceeds of US$373 million after unit issuance costs. TCPL contributed approximately US$8 million to maintain its two per cent general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution gain of $29 million ($47 million pre-tax) was recorded in Additional Paid-In Capital.

Gas Pacifico/INNERGY
On November 26, 2014, TCPL sold its 30 per cent equity investments in Gas Pacifico and INNERGY for aggregate gross proceeds of $9 million and recognized a gain of $9 million ($8 million after tax).

26. 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:

year ended December 31 (millions of Canadian dollars)	**Minimum Lease Payments**	**Amounts Recoverable under Sub-leases**	**Net Payments**
2015	348	48	300
2016	335	47	288
2017	335	48	287
2018	250	27	223
2019	232	23	209
2020 and thereafter	407	20	387
	1,907	213	1,694

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to five years. Net rental expense on operating leases in 2014 was $114 million (2013 – $98 million; 2012 – $84 million).

TCPL's commitments under the 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. Fixed payments under these PPAs have been included in the above operating leases table. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. TCPL's share of payments under the PPAs in 2014 was $391 million (2013 – $242 million; 2012 – $238 million). The generating capacities and expiry dates of the PPAs are as follows:

	MW	**Expiry Date**
Sundance A	560	December 31, 2017
Sheerness	756	December 31, 2020

TCPL 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.

Other Commitments

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2014, TCPL was committed to Natural Gas Pipelines capital expenditures totaling approximately $0.9 billion (2013 – $1.3 billion), primarily related to construction costs related to the Mexican and other natural gas pipeline projects.

At December 31, 2014, the Company was committed to Liquids Pipelines capital expenditures totaling approximately $1.8 billion (2013 – $2.5 billion), primarily related to construction costs of Keystone XL, Grand Rapids and Northern Courier.

At December 31, 2014, the Company was committed to Energy capital expenditures totaling approximately $0.2 billion (2013 – $0.1 billion), primarily related to capital costs of the Napanee Generating Station.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2014, the Company had accrued approximately $31 million (2013 – $32 million; 2012 – $37 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TCPL and its subsidiaries are subject to various legal proceedings, arbitrations 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

TCPL and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust (BPC), have each severally guaranteed certain contingent financial obligations of Bruce B related to a lease agreement and contractor and supplier services. In addition, TCPL and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement and certain other financial obligations. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in Other Long-Term Liabilities. Information regarding the Company's guarantees is as follows:

		2014		2013	
year ended December 31 (millions of Canadian dollars)	**Term**	**Potential Exposure[1]**	**Carrying Value**	**Potential Exposure[1]**	**Carrying Value**
Bruce Power	Ranging to 2019[2]	634	6	740	8
Other jointly owned entities	Ranging to 2040	104	14	51	10
		738	20	791	18

1 TCPL's share of the potential estimated current or contingent exposure.

2 Except for one guarantee with no termination date.

27. RELATED PARTY TRANSACTIONS

The following amounts are included in Due from Affiliates:

(millions of Canadian $)	Maturity Date	2014 Outstanding December 31	2014 Effective Interest Rate	2013 Outstanding December 31	2013 Effective Interest Rate
Discount Notes[1]	2015	**2,597**	**1.3%**	2,721	1.3%
Credit Facility[2]		**245**	**3.0%**	–	–
		2,842		2,721	

1 Issued to TransCanada. Interest on the discount notes is equivalent to current commercial paper rates.

2 Issued to TransCanada. This facility is repayable on demand and bears interest at the Royal Bank of Canada prime rate per annum.

In 2014, interest income included $37 million as a result of inter-corporate lending to TransCanada (2013 – $38 million; 2012 – $41 million).

At December 31, 2014, Accounts Receivable included $59 million due from TransCanada (December 31, 2013 – $43 million).

The following amounts are included in Due to Affiliates:

(millions of Canadian $)	Maturity Date	2014 Outstanding December 31	2014 Effective Interest Rate	2013 Outstanding December 31	2013 Effective Interest Rate
Credit Facility[1]	2016	**866**	**3.8%**	865	3.8%
Credit Facility[2]		**–**	**–**	574	3.0%
		866		1,439	

1 TransCanada has an unsecured $3.5 billion credit facility with a subsidiary of TCPL. Interest on this facility is charged at Reuters prime rate plus 75 basis points.

2 TCPL's demand revolving credit arrangement with TransCanada is $2.0 billion (or a U.S. dollar equivalent). This facility bears interest at the Royal Bank of Canada prime rate per annum, or the U.S. base rate per annum. This facility may be terminated at any time at TransCanada's option.

In December 2014, interest expense included $37 million of interest charges as a result of inter-corporate borrowing (2013 – $62 million; 2012 – $61 million).

At December 31, 2014, Accounts Payable and Other included $16 million due to TransCanada (December 31, 2013 – nil)

At December 31, 2014, Accrued Interest included $1 million of interest payable to TransCanada (December 31, 2013 – $1 million).

In 2014, the Company made interest payments of $37 million to TransCanada (2013 – $62 million; 2012 – $62 million).

28. SUBSEQUENT EVENTS

On January 12, 2015 TCPL completed its offering of US$500 million 1.88 per cent Senior Notes due January 12, 2018 and US$250 million Floating Rate Senior Notes due January 12, 2018.