Quarterly report to shareholders

Second quarter 2014

Financial highlights

(unaudited - millions of $)	three months ended June 30 2014	three months ended June 30 2013	six months ended June 30 2014	six months ended June 30 2013
Income				
Revenue	**2,234**	2,009	**5,118**	4,261
Net income attributable to common shares	**443**	381	**875**	839
Comparable EBITDA[1]	**1,217**	1,143	**2,613**	2,311
Comparable earnings[1]	**359**	373	**801**	755
Operating cash flow				
Funds generated from operations[1]	**919**	949	**2,017**	1,861
Decrease/(increase) in operating working capital	**208**	(127)	**82**	(335)
Net cash provided by operations	**1,127**	822	**2,099**	1,526
Investing activities				
Capital expenditures	**(967)**	(1,109)	**(1,745)**	(2,038)
Equity investments	**(40)**	(39)	**(129)**	(71)
Acquisitions	—	(55)	—	(55)
Proceeds from sale of assets, net of transaction costs	**187**	—	**187**	—
Basic common shares outstanding (millions)				
Average for the period	**775**	749	**770**	747
End of period	**779**	749	**779**	749

1 Comparable EBITDA, comparable earnings, and funds generated from operations are all non-GAAP measures. See non-GAAP measures section for more information.

Management's discussion and analysis

July 31, 2014

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada PipeLines Limited. It discusses our business, operations, financial position, risks and other factors for the three and six months ended June 30, 2014, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 30, 2014 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2013 audited consolidated financial statements and notes and the MD&A in our 2013 Annual Report, which have been prepared in accordance with U.S. GAAP.

About this document

Throughout this MD&A, the terms, *we, us, our* and *TCPL* mean TransCanada PipeLines Limited and its subsidiaries.

Abbreviations and acronyms that are not defined in this MD&A are defined in the glossary in our 2013 Annual Report.

All information is as of July 31, 2014 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are forward-looking are based on certain assumptions and on what we know and expect today and generally include words like *anticipate, expect, believe, may, will, should, estimate* or other similar words.

Forward-looking statements in this MD&A may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets

- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2013 Annual Report.

You should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TCPL in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable earnings
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other entities.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings. It is calculated in the same way as EBITDA, less depreciation and amortization.

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period and is used to provide a consistent measure of the cash generating performance of our assets. See Financial condition section for a reconciliation to net cash provided by operations.

Comparable measures

We calculate the comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	income tax expense

Our decision not to include a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- write-downs of assets and investments.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

Consolidated results - second quarter 2014

(unaudited - millions of $)	three months ended June 30 2014	three months ended June 30 2013	six months ended June 30 2014	six months ended June 30 2013
Natural gas pipelines	**496**	399	**1,082**	947
Liquids pipelines[1]	**195**	149	**387**	291
Energy	**216**	243	**473**	442
Corporate	**(27)**	(22)	**(70)**	(59)
Total segmented earnings	**880**	769	**1,872**	1,621
Interest expense	**(305)**	(268)	**(591)**	(540)
Interest income and other	**64**	(1)	**64**	22
Income before income taxes	**639**	500	**1,345**	1,103
Income tax expense	**(165)**	(96)	**(385)**	(210)
Net income	**474**	404	**960**	893
Net income attributable to non-controlling interests	**(31)**	(18)	**(83)**	(43)
Net income attributable to controlling interests	**443**	386	**877**	850
Preferred share dividends	**—**	(5)	**(2)**	(11)
Net income attributable to common shares	**443**	381	**875**	839

1 Previously Oil Pipelines.

Net income attributable to common shares increased by $62 million for the three months ended June 30, 2014 compared to the same period in 2013. Second quarter 2014 results included:

- a gain on sale of Cancarb Limited and its related power generation business of $99 million after tax
- a net loss resulting from the termination of a contract with Niska Gas Storage of $31 million after tax.

Second quarter 2013 results included a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

Net income attributable to common shares increased by $36 million for the six months ended June 30, 2014 compared to the same period in 2013. The 2014 results included:

- a gain on sale of Cancarb Limited and its related power generation business of $99 million after tax
- a net loss resulting from a termination payment to Niska Gas Storage for contract restructuring of $31 million after tax.

The results for the first six months of 2013 included $84 million of Canadian Mainline net income related to 2012 from the NEB decision (RH-003-2011) as well as a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

The items discussed above are excluded from comparable earnings for the relevant periods. Certain unrealized fair value adjustments relating to risk management activities are also excluded from comparable earnings. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Net income attributable to common shares	**443**	381	**875**	839
Specific items (net of tax):				
Energy - Cancarb gain on sale	**(99)**	—	**(99)**	—
Energy - Niska contract termination	**31**	—	**31**	—
Risk management activities[1]	**(16)**	17	**(6)**	25
Natural gas pipelines - NEB decision - 2012	**—**	—	**—**	(84)
Part VI.I income tax adjustment	**—**	(25)	**—**	(25)
Comparable earnings	**359**	373	**801**	755

1

Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Canadian Power	**(2)**	(4)	**(2)**	(6)
U.S. Power	**(9)**	(18)	**(11)**	(17)
Natural gas Storage	**6**	4	**(3)**	1
Foreign exchange	**25**	(9)	**23**	(15)
Income tax attributable to risk management activities	**(4)**	10	**(1)**	12
Total gains/(losses) from risk management activities	**16**	(17)	**6**	(25)

Comparable earnings decreased by $14 million for the three months ended June 30, 2014 compared to the same period in 2013.

This was primarily the net effect of the following:
- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- lower earnings from Western Power as a result of lower realized power prices
- lower equity income from Bruce Power mainly due to increased planned and unplanned outage days at Bruce A, partially offset by fewer outage days at Bruce B
- higher earnings from Mexico pipelines resulting from contract revenues recognized from the Tamazunchale Extension.

Comparable earnings increased by $46 million for the six months ended June 30, 2014 compared to the same period in 2013.

This was primarily the net effect of:
- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from U.S. Power mainly because of higher realized capacity and power prices
- higher earnings from Mexico pipelines resulting from contract revenues recognized from the Tamazunchale Extension
- higher earnings from U.S. natural gas pipelines due to higher transportation revenues at Great Lakes and higher contributions from TC PipeLines, LP reflecting colder winter weather and increased demand.

The stronger U.S. dollar this quarter compared to the same period in 2013 positively impacted the results in our U.S. businesses, which were mostly offset by a corresponding increase in interest expense on U.S. dollar-denominated debt as well as realized losses on foreign exchange hedges used to manage our net exposure through our hedging program.

CAPITAL PROGRAM

We are developing quality projects under our long-term capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cashflow.

Our capital program is comprised of $12 billion of small to medium-sized projects and $26 billion of large scale projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

at June 30, 2014 (unaudited - billions of $)	Segment	Expected In-Service Date	Estimated Project Cost	Amount Spent
Small to medium-sized projects				
Tamazunchale Extension[1]	Natural Gas Pipelines	2014	US 0.6	US 0.5
Ontario Solar	Energy	2014-2015	0.5	0.2
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.4	US 0.3
Heartland and TC Terminals	Liquids Pipelines	2016	0.9	0.1
Keystone Hardisty Terminal	Liquids Pipelines	Approximately 2 years from date Keystone XL permit received	0.3	0.1
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.5
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.1
Grand Rapids[2]	Liquids Pipelines	2015-2017	1.5	0.1
Northern Courier	Liquids Pipelines	2017	0.8	0.1
NGTL System - North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
- Merrick	Natural Gas Pipelines	2020	1.9	—
- Other	Natural Gas Pipelines	2014-2016	0.5	0.2
Napanee	Energy	2017 or 2018	1.0	—
			11.5	2.3
Large scale projects[3]				
Keystone XL[4]	Liquids Pipelines	Approximately 2 years from date permit received	US 5.4	US 2.4
Energy East[5]	Liquids Pipelines	2018	12.0	0.3
Prince Rupert Gas Transmission	Natural Gas Pipelines	2018	5.0	0.2
Coastal GasLink	Natural Gas Pipelines	2018+	4.0	0.2
			26.4	3.1
			37.9	5.4

1 A force majeure has delayed completion of construction, however, revenue has been recorded in second quarter 2014 as per the terms of the Transportation Service Agreement.
2 Represents our 50 per cent share.
3 Subject to cost adjustments due to market conditions, route refinement, permitting conditions and scheduling.
4 Estimated project cost will increase depending on the timing of the Presidential permit.
5 Excludes transfer of Canadian Mainline natural gas assets.

Outlook

The earnings outlook previously included in the 2013 Annual Report is expected to be impacted by:

- the gain on sale of Cancarb Limited and its related power generation facility
- the termination payment to Niksa Gas Storage for the contract restructuring
- increased outage days at Bruce A.

See the MD&A in our 2013 Annual Report for further information about our outlook.

Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable EBITDA	**759**	644	**1,607**	1,390
Comparable depreciation and amortization[1]	**(263)**	(245)	**(525)**	(485)
Comparable EBIT	**496**	399	**1,082**	905
Specific item:				
NEB decision - 2012	**—**	—	**—**	42
Segmented earnings	**496**	399	**1,082**	947

1 In 2014, comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization. In 2013, comparable depreciation is adjusted by $13 million relating to the impact from the NEB decision (RH-003-2011).

Our Natural Gas Pipelines segmented earnings increased by $97 million for the three months ended June 30, 2014 and by $135 million for the six months ended June 30, 2014 compared to the same periods in 2013. Natural gas segmented earnings for the six months ended June 30, 2013 included $42 million related to the 2012 impact of the NEB decision (RH-003-2011). This amount has been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA and are discussed below.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Canadian Pipelines				
Canadian Mainline	**312**	263	**627**	543
NGTL System	**205**	193	**424**	375
Foothills	**27**	28	**54**	57
Other Canadian pipelines (TQM[1], Ventures LP)	**5**	7	**10**	13
Canadian Pipelines - comparable EBITDA	**549**	491	**1,115**	988
Comparable depreciation and amortization	**(204)**	(190)	**(407)**	(374)
Canadian Pipelines - comparable EBIT	**345**	301	**708**	614
U.S. and International Pipelines (US$)				
ANR	**33**	32	**111**	122
TC PipeLines, LP[1,2]	**21**	13	**47**	30
Great Lakes[3]	**9**	8	**28**	18
Other U.S. pipelines (Bison[4], Iroquois[1], GTN[4], Portland[5])	**29**	49	**74**	120
Mexico (Guadalajara, Tamazunchale)	**49**	26	**74**	52
International and other[6]	**(1)**	(4)	**(2)**	(6)
Non-controlling interests[7]	**54**	31	**127**	74
U.S. and International Pipelines - comparable EBITDA	**194**	155	**459**	410
Comparable depreciation and amortization	**(54)**	(54)	**(108)**	(109)
U.S. and International Pipelines - comparable EBIT	**140**	101	**351**	301
Foreign exchange impact	**13**	2	**34**	4
U.S. and International Pipelines - comparable EBIT (Cdn$)	**153**	103	**385**	305
Business Development comparable EBITDA and EBIT	**(2)**	(5)	**(11)**	(14)
Natural Gas Pipelines - comparable EBIT	**496**	399	**1,082**	905

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.

2 Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of		
	July 1, 2013	**May 22, 2013**	**January 1, 2013**
TC PipeLines, LP	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:			
GTN/Bison	20.2	7.2	8.3
Great Lakes	13.4	13.4	15.5

3 Represents our 53.6 per cent direct ownership interest.
4 Effective July 1, 2013, represents our 30 per cent direct ownership interest. Prior to July 1, 2013, our direct ownership interest was 75 per cent.
5 Represents our 61.7 per cent ownership interest.
6 Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International pipelines.
7 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

CANADIAN PIPELINES

Net income and comparable EBITDA for our rate-regulated Canadian Pipelines are affected by our approved ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA and comparable EBIT but do not impact net income as they are recovered in revenue on a flow-through basis.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Canadian Mainline - net income	**58**	67	**124**	218
Canadian Mainline - comparable earnings	**58**	67	**124**	134
NGTL System	**58**	58	**121**	114
Foothills	**4**	5	**8**	9

Canadian Mainline's net income decreased by $9 million and $94 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 as net income in first quarter 2013 included $84 million related to the 2012 impact of the NEB decision (RH-003-2011), which was excluded from comparable earnings. Comparable earnings in both years reflect an ROE of 11.50 per cent on deemed common equity of 40 per cent and have decreased by $9 million and $10 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 because of a lower average investment base as well as carrying charges owed to shippers on the Tolls Stabilization Account.

Net income for the NGTL System was unchanged for the three months ended June 30, 2014 and increased by $7 million for the six months ended June 30, 2014 compared to the same periods in 2013. A higher average investment base as well as an increase in the ROE had a positive impact on earnings. These increases were partially offset by increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. The Settlement included an ROE of 10.10 per cent on deemed common equity of 40 per cent and included annual fixed amounts for certain OM&A costs. Results for the three and six months ended June 30, 2013 reflect the previously approved ROE of 9.70 per cent on deemed common equity of 40 per cent.

U.S. AND INTERNATIONAL PIPELINES

Earnings for our U.S. natural gas pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and property taxes. ANR is also affected by the contracting and pricing of its storage capacity and incidental commodity sales.

Comparable EBITDA for the U.S. and international pipelines increased by US$39 million and US$49 million for the three and six months ended June 30, 2014 compared to the same periods in 2013. This was the net effect of:

- contract revenues recognized from the Tamazunchale Extension in the three months ended June 30, 2014. The Tamazunchale Extension project has experienced delays in completing the construction due to archeological findings along the pipeline route. The CFE agreed that, under the terms of the TSA, these delays constitute force majeure and, as a result, collection and recognition of revenue commenced on March 9, 2014.
- higher transportation revenues at Great Lakes and higher contributions from TC PipeLines, LP reflecting colder winter weather and increased demand
- higher OM&A costs at ANR as well as lower storage revenues in first quarter 2014.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $18 million and $40 million for the three and six months ended June 30, 2014 compared to the same periods in 2013, mainly because of a higher investment base and higher depreciation rates on the NGTL System.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

six months ended June 30	**Canadian Mainline[1]**		**NGTL System[2]**		**ANR[3]**	
(unaudited)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Average investment base (millions of $)	**5,667**	5,871	**6,179**	5,882	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**842**	704	**1,996**	1,832	**863**	823
Average per day	**4.7**	3.9	**11.0**	10.1	**4.8**	4.6

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the six months ended June 30, 2014 were 599 Bcf (2013 – 397 Bcf). Average per day was 3.3 Bcf (2013 – 2.2 Bcf).

2 Field receipt volumes for the NGTL System for the six months ended June 30, 2014 were 1,879 Bcf (2013 – 1,840 Bcf). Average per day was 10.4 Bcf (2013 – 10.2 Bcf).

3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

Liquids Pipelines[1]

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2014	**2013**	**2014**	**2013**
Comparable EBITDA	**249**	186	**490**	365
Comparable depreciation and amortization[2]	**(54)**	(37)	**(103)**	(74)
Comparable EBIT	**195**	149	**387**	291
Specific items	**—**	—	**—**	—
Segmented earnings	**195**	149	**387**	291

1 Previously Oil Pipelines.
2 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.

Liquids Pipelines segmented earnings increased by $46 million for the three months ended June 30, 2014 and increased by $96 million for the six months ended June 30, 2014 compared to the same periods in 2013. Liquids Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA and are discussed below.

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2014	**2013**	**2014**	**2013**
Keystone Pipeline System	**256**	187	**504**	373
Liquids Pipelines Business Development	**(7)**	(1)	**(14)**	(8)
Liquids Pipelines - comparable EBITDA	**249**	186	**490**	365
Comparable depreciation and amortization	**(54)**	(37)	**(103)**	(74)
Liquids Pipelines - comparable EBIT	**195**	149	**387**	291

Comparable EBIT denominated as follows:				
Canadian dollars	**50**	52	**99**	99
U.S. dollars	**133**	95	**262**	189
Foreign exchange impact	**12**	2	**26**	3
	195	149	**387**	291

Comparable EBITDA from our Keystone Pipeline System is generated primarily by providing pipeline capacity to shippers for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and provides opportunities to generate incremental earnings.

Comparable EBITDA for the Keystone Pipeline System increased by $69 million for the three months ended June 30, 2014 and increased by $131 million for the six months ended June 30, 2014 compared to the same periods in 2013. These increases were primarily due to:

- incremental earnings from the Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

BUSINESS DEVELOPMENT

Business development expenses for the three and six months ended June 30, 2014 were $6 million higher than the same periods in 2013 primarily due to lower capitalization of business development costs in 2014.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $17 million for the three months ended June 30, 2014 and by $29 million for the six months ended June 30, 2014 compared to the same periods in 2013 due to the Gulf Coast extension being placed in service.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable EBITDA	**231**	330	**576**	607
Comparable depreciation and amortization[1]	**(77)**	(69)	**(154)**	(143)
Comparable EBIT	**154**	261	**422**	464
Specific items (pre-tax):				
Cancarb gain on sale	**108**	—	**108**	—
Niska contract termination	**(41)**	—	**(41)**	—
Risk management activities	**(5)**	(18)	**(16)**	(22)
Segmented earnings	**216**	243	**473**	442

1 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.

Our Energy segmented earnings decreased by $27 million for the three months ended June 30, 2014 and increased by $31 million for the six months ended June 30, 2014 compared to the same periods in 2013.

Energy segmented earnings included the following specific items for the three and six months ended June 30, 2014:

- a gain of $108 million ($99 million after tax) on the sale of Cancarb Limited and its related power generation business, which closed on April 15, 2014
- a net loss resulting from the contract termination payment to Niska Gas Storage of $41 million ($31 million after-tax) effective April 30, 2014
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2014**	**2013**	**2014**	**2013**
Canadian Power	**(2)**	(4)	**(2)**	(6)
U.S. Power	**(9)**	(18)	**(11)**	(17)
Natural Gas Storage	**6**	4	**(3)**	1
Total losses from risk management activities	**(5)**	(18)	**(16)**	(22)

The remainder of the Energy segmented earnings are equivalent to comparable EBITDA and comparable EBIT and are discussed below.

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2014	**2013**	**2014**	**2013**
Canadian Power				
Western Power	**46**	117	**118**	191
Eastern Power[1]	**70**	69	**163**	159
Bruce Power	**24**	59	**88**	90
Canadian Power - comparable EBITDA[2]	**140**	245	**369**	440
Comparable depreciation and amortization	**(45)**	(43)	**(89)**	(86)
Canadian Power - comparable EBIT[2]	**95**	202	**280**	354
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**88**	80	**174**	147
Comparable depreciation and amortization	**(27)**	(23)	**(54)**	(51)
U.S. Power - comparable EBIT	**61**	57	**120**	96
Foreign exchange impact	**6**	1	**11**	2
U.S. Power - comparable EBIT (Cdn$)	**67**	58	**131**	98
Natural Gas Storage and other				
Natural Gas Storage and other - comparable EBITDA	**2**	9	**29**	27
Comparable depreciation and amortization	**(3)**	(2)	**(6)**	(5)
Natural Gas Storage and other - comparable EBIT	**(1)**	7	**23**	22
Business Development comparable EBITDA and EBIT	**(7)**	(6)	**(12)**	(10)
Energy - comparable EBIT[2]	**154**	261	**422**	464

1 Includes four Ontario solar facilities acquired between June and December 2013.
2 Includes our share of equity income from our investments in ASTC Power Partnership, Portlands Energy and Bruce Power.

Comparable EBITDA for Energy decreased by $99 million for the three months ended June 30, 2014 compared to the same period in 2013. The decrease was the net effect of:

- lower earnings from Western Power as a result of lower realized power prices
- lower equity income from Bruce Power mainly due to increased planned and unplanned outage days at Bruce A, partially offset by fewer outage days at Bruce B
- higher earnings from U.S. Power mainly because of higher realized capacity prices
- lower earnings from Natural Gas Storage due to lower realized natural gas storage spreads.

Comparable EBITDA for Energy decreased by $31 million for the six months ended June 30, 2014 compared to the same period in 2013. The decrease was the net effect of:

- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from U.S. Power mainly because of higher realized capacity and power prices
- higher earnings from Eastern Power due to the incremental earnings from the Ontario solar facilities acquired in 2013.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Revenue				
Western Power	**160**	157	**341**	297
Eastern Power[1]	**88**	91	**230**	200
Other[2]	**6**	22	**57**	53
	254	270	**628**	550
Income from equity investments[3]	**8**	66	**28**	88
Commodity purchases resold	**(90)**	(83)	**(191)**	(150)
Plant operating costs and other	**(58)**	(71)	**(186)**	(144)
Exclude risk management activities	**2**	4	**2**	6
Comparable EBITDA	**116**	186	**281**	350
Comparable depreciation and amortization	**(45)**	(43)	**(89)**	(86)
Comparable EBIT	**71**	143	**192**	264

Breakdown of comparable EBITDA				
Western Power	**46**	117	**118**	191
Eastern Power	**70**	69	**163**	159
Comparable EBITDA	**116**	186	**281**	350

1 Includes four Ontario solar facilities acquired between June and December 2013.
2 Includes sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black. Sale of Cancarb closed April 15, 2014.
3 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

(unaudited)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**611**	687	**1,220**	1,357
Eastern Power[1]	**596**	750	**1,873**	2,096
Purchased				
Sundance A & B and Sheerness PPAs[2]	**2,598**	1,788	**5,398**	3,495
Other purchases	**2**	—	**7**	—
	3,807	3,225	**8,498**	6,948
Sales				
Contracted				
Western Power	**2,434**	1,939	**4,895**	3,646
Eastern Power[1]	**596**	750	**1,873**	2,096
Spot				
Western Power	**777**	536	**1,730**	1,206
	3,807	3,225	**8,498**	6,948
Plant availability[3]				
Western Power[4]	**94%**	92%	**95%**	94%
Eastern Power[1,5]	**73%**	80%	**86%**	88%

1 Includes four Ontario solar facilities acquired between June and December 2013.
2 Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013.

3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Does not include facilities that provide power to TCPL under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA decreased by $71 million and $73 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A PPA Unit 1 in September 2013 and Unit 2 in October 2013 which also resulted in increased volume purchases and sales.

Average spot market power prices in Alberta decreased by 66 per cent from $123/MWh to $42/MWh for the three months ended June 30, 2014 and 45 per cent from $94/MWh to $52/MWh for the six months ended June 30, 2014, compared to the same periods in 2013. Strong coal fleet availability and new wind capacity have resulted in significantly lower prices in spite of strong growth in Alberta power demand. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

Seventy-six per cent of Western Power sales volumes were sold under contract in second quarter 2014 and 78 per cent in second quarter 2013.

Eastern Power

Eastern Power's comparable EBITDA increased by $1 million and $4 million for the three and six months ended June 30, 2014 compared to the same period in 2013 mainly due to the incremental earnings from the four Ontario solar facilities acquired in 2013.

Lower plant availability in Eastern Power in second quarter 2014 was the result of lower availability at Halton Hills because of a maintenance outage.

BRUCE POWER

Our proportionate share

(unaudited - millions of $, unless noted otherwise)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Income/(loss) from equity investments[1]				
Bruce A	**(2)**	51	**47**	87
Bruce B	**26**	8	**41**	3
	24	59	**88**	90
Comprised of:				
Revenues	**265**	306	**565**	593
Operating expenses	**(164)**	(172)	**(321)**	(344)
Depreciation and other	**(77)**	(75)	**(156)**	(159)
	24	59	**88**	90
Bruce Power - Other information				
Plant availability[2]				
Bruce A	**64%**	88%	**72%**	77%
Bruce B	**93%**	80%	**89%**	79%
Combined Bruce Power	**79%**	84%	**82%**	78%
Planned outage days				
Bruce A	**84**	33	**84**	123
Bruce B	**25**	70	**74**	140
Unplanned outage days				
Bruce A	**45**	—	**105**	8
Bruce B	**—**	3	**—**	12
Sales volumes (GWh)[1]				
Bruce A	**2,037**	2,464	**4,564**	4,561
Bruce B	**2,048**	1,726	**3,972**	3,460
	4,085	4,190	**8,536**	8,021
Realized sales price per MWh[3]				
Bruce A	**$72**	$71	**$71**	$70
Bruce B	**$55**	$54	**$55**	$53
Combined Bruce Power	**$62**	$63	**$62**	$61

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes exclude deemed generation.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Calculated based on actual and deemed generation. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A decreased by $53 million and $40 million for the three and six months ended June 30, 2014 compared to the same periods in 2013. The decrease was mainly due to:

- lower earnings from Unit 3 due to a planned outage which began in April 2014
- lower volumes due to increased unplanned outage days, primarily on Units 1 and 2.

These decreases were partially offset by higher earnings from Unit 4 following the completion of the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

Equity income from Bruce B increased by $18 million for the three months ended June 30, 2014 and $38 million for the six months ended June 30, 2014 compared to the same periods in 2013. These increases were mainly due to higher volumes and lower operating costs resulting from fewer planned and unplanned outage days.

Under the contract with the OPA, all of the output from Bruce A Units 1 to 4 is sold at a fixed price per MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A fixed price	per MWh
April 1, 2014 - March 31, 2015	$71.70
April 1, 2013 - March 31, 2014	$70.99
April 1, 2012 - March 31, 2013	$68.23

Under the same contract, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	per MWh
April 1, 2014 - March 31, 2015	$52.86
April 1, 2013 - March 31, 2014	$52.34
April 1, 2012 - March 31, 2013	$51.62

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price. While the first quarter 2014 average spot price exceeded the floor price, spot prices have since fallen below the floor price and are expected to remain there for the remainder of 2014. As a result, Bruce B is expected to recognize annual revenues at the floor price and amounts equivalent to that received above it in first quarter 2014 are expected to be repaid to the OPA.

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

The overall plant availability percentage in 2014 is expected to be in the low 80s for Bruce A and high 80s for Bruce B. Planned maintenance on one of the Bruce B units is scheduled to occur in fourth quarter 2014.

U.S. POWER

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$)	**2014**	**2013**	**2014**	**2013**
Revenue				
Power[1]	**311**	316	**1,054**	779
Capacity	**96**	77	**166**	124
	407	393	**1,220**	903
Commodity purchases resold	**(218)**	(197)	**(767)**	(503)
Plant operating costs and other[2]	**(109)**	(134)	**(289)**	(270)
Exclude risk management activities	**8**	18	**10**	17
Comparable EBITDA	**88**	80	**174**	147
Comparable depreciation and amortization	**(27)**	(23)	**(54)**	(51)
Comparable EBIT	**61**	57	**120**	96

1 The realized and unrealized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues.
2 Includes the cost of fuel consumed in generation.

Sales volumes and plant availability

(unaudited)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Physical sales volumes (GWh)				
Supply				
Generation	**2,006**	1,761	**3,244**	2,812
Purchased	**1,865**	1,878	**4,694**	4,357
	3,871	3,639	**7,938**	7,169
Plant availability[1]	**89%**	91%	**87%**	85%

1 The percentage of time the plant was available to generate power, regardless of whether it was running.

U.S. Power's comparable EBITDA increased US$8 million for the three months ended June 30, 2014 compared to the same period in 2013. The increase was the net effect of:
- higher realized capacity prices in New York
- higher generation at our hydro facilities
- higher prices and related costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

U.S. Power's comparable EBITDA increased US$27 million for the six months ended June 30, 2014 compared to the same period in 2013. The increase was the net effect of:
- higher realized capacity prices in New York
- higher realized power prices and higher generation in New England
- higher realized power prices and higher generation in New York offset by higher plant operating costs due to higher fuel prices
- higher prices and related costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

Wholesale electricity prices in New York and New England were higher for the six months ended June 30, 2014 compared to the same period in 2013 primarily due to significantly higher spot power prices in first quarter 2014. Colder winter temperatures and gas transmission constraints resulted in higher natural gas prices in the predominantly gas-fired New England and New York power markets in first quarter 2014 compared to the same period in 2013.

Average spot power prices for the three months ended June 30, 2014 in New England of $40/MWh were unchanged and in New York City spot power prices decreased 12 per cent to an average of $38/MWh compared to the same period in 2013. Average spot power prices for the six months ended June 30, 2014 in New England increased 45 per cent to $93/MWh and in New York City spot power prices increased 44 per cent to an average of $82/MWh compared to the same period in 2013.

Spot capacity prices in New York City were on average 26 and 46 per cent higher for the three and six months ended June 30, 2014 compared to the same periods in 2013. This, and the impact of hedging activities, resulted in higher realized capacity prices in New York.

Physical sales volumes for the three and six months ended June 30, 2014 were higher than the same period in 2013. For the three months ended June 30, 2014, generation volumes at our Ravenswood and hydro facilities were higher than the same period in 2013. For the six months ended June 30, 2014, generation at our Ravenswood facility and purchased volumes sold to wholesale, commercial and industrial customers in our PJM markets were also higher than in the same period in 2013.

As at June 30, 2014, approximately 3,500 GWh or 60 per cent of U.S. Power's planned generation is contracted for the remainder of 2014, and 3,100 GWh or 35 per cent for 2015. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA decreased $7 million for the three months ended June 30, 2014 and increased $2 million for six months ended June 30, 2014 compared to the same periods in 2013. The decrease in the three months ended June 30, 2014 was primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas storage spreads. The increase in the six months ended June 30, 2014 was primarily due to increased proprietary storage revenues recognized in the first quarter as a result of higher realized natural gas storage spreads, partially offset by decreased third party storage revenues. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

Recent developments

NATURAL GAS PIPELINES

Canadian Regulated Pipelines

NGTL System
We continued to expand the NGTL System in second quarter 2014. Of the $400 million of facilities that received NEB approval, approximately $250 million have been placed in service as of June 30, 2014. In addition, we have approximately $1.9 billion in projects that have been applied for but are not yet approved by the NEB, mainly comprised of the $1.7 billion North Montney project further described below.

In March 2014, we received an NEB Safety Order in response to recent pipeline releases on the NGTL System. The order required us to reduce the maximum operating pressure on three per cent of NGTL's pipeline segments. On March 28, 2014, we filed a request for a review and variance of the Order that would minimize gas disruptions while still maintaining a high level of safety. In April 2014, the NEB granted the review and variance request with certain conditions. We are accelerating components of our integrity management program to address the NEB order.

Merrick Mainline Pipeline Project
On June 4, 2014, we announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System.

The proposed Merrick Mainline Pipeline Project will transport natural gas sourced through the NGTL System to the inlet of a proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The $1.9 billion project consists of approximately 260 km (161 miles) of 48-inch diameter pipe.

We anticipate filing an application for approvals to build and operate the system with the NEB in fourth quarter 2014. Subject to the necessary approvals, including a positive final investment decision for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.

North Montney Mainline Project
The NEB issued a Hearing Order in February 2014 for the $1.7 billion North Montney Pipeline Project, which is an extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. The proposed project consists of approximately 300 km (186 miles) of pipeline and is expected to be placed in service in two sections, Aitken Creek in second quarter 2016 and Kahta in second quarter 2017.

On June 17, 2014, the NEB revised the procedural schedule which has resulted in the oral portion of the hearing being rescheduled to mid-October 2014 for the Calgary phase, and mid-November for the Fort St. John phase. We now anticipate an NEB decision on the application in first quarter 2015.

Canadian Mainline

LDC Settlement
In March 2014, the NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information. On May 9, 2014, the NEB released a Hearing Order that sets out a hearing process and schedule for the 2015 - 2030 Mainline Tolls application that incorporates the LDC Settlement, with the oral portion set to begin September 9, 2014.

Eastern Mainline Project
On May 8, 2014, we filed a project description with the NEB for the Eastern Mainline Project. The proposed project will add new facilities to our existing Canadian Mainline natural gas transmission system in southeastern Ontario as a result of the proposed transfer of a portion of the Canadian Mainline capacity to crude oil from natural gas service as part of our Energy East Pipeline and an open season that closed in January 2014. The proposed scope of the project will add 0.6 Bcf/day of new capacity and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments contracted services in the Eastern Triangle segment of the Canadian Mainline. Subject to regulatory approvals, the project is expected to be in service in second quarter 2017.

U.S. Pipelines

ANR Pipeline
We have secured almost 2.0 Bcf/d of firm natural gas transportation commitments on the ANR Pipeline's Southeast Main Line at maximum rates for an average term of 23 years. Approximately 1.25 Bcf/d of new contracts will commence in late 2014 including

volume commitments from the ANR Lebanon Lateral Reversal project, with the remaining volume commencing in 2015. These contracts will enable growing Utica and Marcellus shale gas supply to move to both northern delivery points and southbound to the U.S. Gulf Coast. As a result, approximately US$100 million of capital investment will be required to bring this additional supply to market. We are also assessing further demand which could result in incremental opportunities to enhance and expand the ANR Pipeline system.

Mexican Pipelines

Tamazunchale Pipeline Extension Project
Construction of the US$600 million extension is currently expected to be completed by the end of September 2014 with delays attributed to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays are recognized as a force majeure with provisions allowing for collection of revenue as per the original service commencement of March 9, 2014.

LNG Pipeline Projects

Coastal GasLink
In first quarter 2014, we filed the Environmental Assessment Certificate application with the B.C. Environmental Assessment Office (EAO) and the B.C. Oil and Gas Commission application. We are currently updating field work along the pipeline route to support the regulatory applications and refine the capital cost estimates.

Prince Rupert Gas Transmission
The Environmental Assessment application submitted to the EAO in April 2014 was deemed complete by the EAO. The EAO initiated a 180-day review period which included a 45-day public comment period that was completed on July 10, 2014. A facilities application was also filed with the B.C. Oil and Gas Commission in April 2014. Regulatory approval for the pipeline is expected in fourth quarter 2014 and a final investment decision from Pacific Northwest LNG is expected to follow at the end of 2014.

Alaska
In April 2014, the State of Alaska passed new legislation that will transition from the *Alaska Gasline Inducement Act* (AGIA) and enable a new commercial arrangement to be established with us, the three major Alaska North Slope producers, and the Alaska Gasline Development Corp. It was also agreed that an LNG export project, rather than a pipeline to Alberta, is currently the best opportunity to commercialize Alaska North Slope gas resources in current market conditions.

On June 9, 2014, we executed an agreement with the State of Alaska to abandon the AGIA license and executed a Precedent Agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. On June 30, 2014, the Alaska LNG Project entered the pre-front end engineering and design (pre-FEED) phase following the execution of a Joint Venture Agreement among ourselves, the three major Alaska North Slope producers and Alaska Gasline Development Corp. The pre-FEED work is anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The Precedent Agreement provides us with full recovery of development costs in the event the project does not proceed.

LIQUIDS PIPELINES

Keystone Pipeline System
We finished constructing the 780 km (485 mile) 36-inch pipeline of the Gulf Coast extension of the Keystone Pipeline System, from Cushing, Oklahoma to the U.S. Gulf Coast. Crude oil transportation service on the project began January 22, 2014.

Keystone XL
On January 31, 2014, the DOS released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is “unlikely to significantly impact the rate of extraction in the oil sands” and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period that was to last up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment. The 30 day public comment period has concluded. On April 18, 2014, the DOS announced that the National Interest Determination period has been extended indefinitely to allow them to consider the potential impact of the case discussed below on the Nebraska portion of the pipeline route.

In February 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. Nebraska’s Attorney General has filed an appeal and the Nebraska Supreme Court is expected to hear the appeal in September 2014. As of June 30, 2014, we have invested US$2.4 billion in the Keystone XL project.

Cushing Marketlink

Construction continues on the Cushing Marketlink receipt facilities at Cushing, Oklahoma. Cushing Marketlink will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System. Construction is expected to be completed in third quarter 2014.

Energy East Pipeline

In March 2014, we filed the project description with the NEB. This is the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

Subject to regulatory approvals, the pipeline is anticipated to commence deliveries to Québec in 2018, with service to New Brunswick to follow in late 2018. We continue to participate in Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in third quarter 2014 for approvals to construct and operate the pipeline project and terminal facilities.

Heartland Pipeline and TC Terminals

The Heartland Pipeline and TC Terminals will include a 200 km (125 miles) crude oil pipeline connecting the Edmonton/ Heartland, Alberta market region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. In February 2014, the application for the terminal facility was approved by the Alberta Energy Regulator.

Northern Courier Pipeline

In October 2013, Suncor Energy announced that the Fort Hills Energy LP is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.

On July 18, 2014, the Alberta Energy Regulator issued a permit approving our application to construct and operate the Northern Courier Pipeline. We currently expect construction to begin in third quarter 2014 and to be in service in 2017.

ENERGY

Cancarb Limited and Cancarb Waste Heat Facility

The sale of Cancarb Limited and its related power generation facility closed on April 15, 2014 for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.

Natural Gas Storage

Effective April 30, 2014, we terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of $31 million in second quarter 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

Ontario Solar

We expect the acquisition of four additional Ontario solar generation facilities to close in late 2014, with the acquisition of the ninth and final facility now expected to close in mid-2015, subject to satisfactory completion of the related construction activities, regulatory approvals, and purchase agreement conditions for each facility. All power produced by the solar facilities is currently or will be sold under 20-year PPAs with the OPA.

Bécancour

In May 2014, we received final approval from the Régie de l'energie for the December 2013 amendment to the original suspension agreement with Hydro-Québec. In addition, Hydro-Québec exercised its option in the amendment to extend the suspension past 2017, and requested further suspension of generation to the end of 2018 which was also approved by the Régie de l'energie.

Other income statement items

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	**(113)**	(123)	**(227)**	(245)
U.S. dollar-denominated (US$)	**(216)**	(185)	**(423)**	(373)
Foreign exchange impact	**(19)**	(5)	**(41)**	(6)
	(348)	(313)	**(691)**	(624)
Other interest and amortization expense	**(20)**	(15)	**(42)**	(30)
Capitalized interest	**63**	60	**142**	115
Comparable interest expense	**(305)**	(268)	**(591)**	(539)
Specific item:				
NEB decision - 2012	**—**	—	**—**	(1)
Interest expense	**(305)**	(268)	**(591)**	(540)

Comparable interest expense increased by $37 million and $52 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 because of the following:

- higher interest expense due to debt issues of:
  - US$1.25 billion in February 2014
  - US$1.25 billion in October 2013
  - US$500 million in July 2013
  - $750 million in July 2013
  - US$500 million in July 2013 by TC PipeLines, LP
- higher foreign exchange on interest expense related to U.S. denominated debt, partially offset by Canadian and U.S. dollar-denominated debt maturities.

These increases were partially offset by higher capitalized interest primarily for Keystone XL, Mexican, and other liquids and LNG pipeline projects partially offset by the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable interest income and other	**39**	8	**41**	36
Specific items (pre-tax):				
NEB decision - 2012	**—**	—	**—**	1
Risk management activities	**25**	(9)	**23**	(15)
Interest income and other	**64**	(1)	**64**	22

Comparable interest income and other increased by $31 million for the three months ended June 30, 2014 compared to the same period in 2013 reflecting lower realized losses in 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income, the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital balances and AFUDC related to our rate-regulated projects, including the Energy East project.

Comparable interest income and other increased $5 million for the six months ended June 30, 2014 compared to the same period in 2013 reflecting increased AFUDC related to our rate-regulated projects, including the Energy East project, offset by higher realized losses in 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income.

(unaudited - millions of $)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Comparable income tax expense	**(162)**	(131)	**(385)**	(289)
Specific items:				
Cancarb gain on sale	**(9)**	—	**(9)**	—
Niska contract termination	**10**	—	**10**	—
NEB decision - 2012	**—**	—	**—**	42
Part VI.I income tax adjustment	**—**	25	**—**	25
Risk management activities	**(4)**	10	**(1)**	12
Income tax expense	**(165)**	(96)	**(385)**	(210)

Comparable income tax expense increased by $31 million and $96 million for the three and six months ended June 30, 2014 compared to the same periods in 2013. The increase was mainly the result of higher pre-tax earnings in 2014 compared to 2013, changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines.

(unaudited - millions of $)	three months ended June 30 2014	2013	six months ended June 30 2014	2013
Net income attributable to non-controlling interests	**(31)**	(18)	**(83)**	(43)
Preferred share dividends	**—**	(5)	**(2)**	(11)

Net income attributable to non-controlling interests increased by $13 million and $40 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013.

Preferred share dividends decreased by $5 million and $9 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 following the redemption of Series Y preferred shares in March 2014.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of an economic cycle, and rely on our cash flow from operations to sustain our business, pay dividends and fund a portion of our growth.

We believe we have the capacity to fund our existing capital program through predictable cash flow from operations, access to capital markets, cash on hand and substantial committed credit facilities.

We access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Funds generated from operations[1]	**919**	949	**2,017**	1,861
Decrease/(increase) in operating working capital	**208**	(127)	**82**	(335)
Net cash provided by operations	**1,127**	822	**2,099**	1,526

1 See the non-GAAP measures section in this MD&A for further discussion of funds generated from operations.

Net cash provided by operations increased by $305 million and $573 million for the three and six months ended June 30, 2014 compared to the same periods in 2013 primarily due to changes in our operating working capital.

At June 30, 2014, our current assets were $5.8 billion and current liabilities were $6.4 billion, leaving us with a working capital deficit of $0.6 billion compared to $0.9 billion at December 31, 2013. This working capital deficiency is considered to be in the normal course of business and is managed through our ability to generate cash flow from operations and our ongoing access to the capital markets.

CASH (USED IN)/PROVIDED BY INVESTING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Capital expenditures	**(967)**	(1,109)	**(1,745)**	(2,038)
Equity investments	**(40)**	(39)	**(129)**	(71)
Acquisitions	**—**	(55)	**—**	(55)
Proceeds from sale of assets, net of transaction costs	**187**	—	**187**	—

Our capital expenditures in 2014 were primarily related to the construction of the Mexican pipelines, expansion of the NGTL System, and construction of the Houston Lateral and Tank Terminals.

In April 2014, we closed the sale of Cancarb Limited for $187 million, net of transaction costs.

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Long-term debt issued, net of issue costs	**16**	10	**1,380**	744
Long-term debt repaid	**(205)**	(695)	**(982)**	(709)
Notes payable issued/(repaid), net	**225**	1,388	**(522)**	559
Dividends and distributions paid	**(387)**	(360)	**(757)**	(705)
Common shares issued, net of issue costs	**675**	—	**1,115**	499
Partnership units of subsidiary issued, net of issue costs	**—**	384	**—**	384
Preferred shares of redeemed	**—**	—	**(200)**	—
Advances (to)/from affiliates, net	**(683)**	36	**(683)**	111

LONG-TERM DEBT ISSUED

Amount (unaudited - millions of $)	Type	Maturity date	Interest rate	Date issued
US$1,250	Senior unsecured notes	March 1, 2034	4.625%	February 2014

LONG-TERM DEBT RETIRED

Amount (unaudited - millions of $)	Type	Retirement date	Interest rate
$450	Medium term notes	January 2014	5.65%
$300	Medium term notes	February 2014	5.05%
$125	Debenture	June 2014	11.10%
$53	Debenture	June 2014	11.20%

COMMON SHARE ISSUANCE

In January 2014, we issued 9.1 million common shares to TransCanada Corporation (TransCanada) resulting in proceeds of $440 million.

In April 2014, we issued 13.3 million common shares to TransCanada resulting in proceeds of $675 million.

PREFERRED SHARE REDEMPTION

In March 2014, we redeemed all four million Series Y preferred shares of TCPL at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y Shares was $200 million and carried an aggregate of $11 million in annualized dividends.

The net proceeds of the above debt and equity offerings were used for general corporate purposes and to reduce short-term indebtedness.

DIVIDENDS

On July 31, 2014, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
The dividend declared for the quarter ending September 30, 2014 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on September 30, 2014.

SHARE INFORMATION

July 28, 2014	
Common shares	**Issued and outstanding**
	779 million

CREDIT FACILITIES

We use committed revolving credit facilities to support our commercial paper programs along with additional demand facilities for general corporate purposes including issuing letters of credit and providing additional liquidity.

At June 30, 2014, we had $6.5 billion in unsecured credit facilities, including:

Amount	Unused capacity	Borrower	Description and Use	Matures
$3.0 billion	$3.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2018
US$1.0 billion	US$1.0 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes	November 2014
US$1.0 billion	US$1.0 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports the TAIL U.S. commercial paper program.	November 2014
$1.3 billion	$0.3 billion	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At June 30, 2014, we had $1.0 billion outstanding in letters of credit under these lines	Demand

See Financial risks and financial instruments for more information about liquidity, market and other risks.

RELATED PARTY DEBT FINANCING

Related party debt consists of amounts due to/from affiliates.

	Amount	For	Matures
Discount Notes	$2.7 billion	Discount notes issued to TransCanada; used for general corporate purposes.	2014
Credit Facility	$0.1 billion	Demand revolving credit facility arrangement with TransCanada.	n/a
Credit Facility	$0.8 billion	TransCanada Energy Investments Ltd. unsecured credit facility agreement; used to repay indebtedness, make partner contributions to Bruce A, and for working capital and general corporate purposes.	2014

CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by approximately $1 billion since December 31, 2013 primarily due to the completion or advancement of capital projects. Our other purchase obligations have decreased by approximately $400 million since December 31, 2013 primarily due to re-contracting for natural gas storage services in Alberta for a shorter period and a reduced average volume. There were no other material changes to our contractual obligations in second quarter 2014 or to payments due in the next five years or after. See the MD&A in our 2013 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to liquidity risk, counterparty credit risk and market risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value. These are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

See our 2013 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2013.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash requirements for a rolling twelve month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in the following areas:

- accounts receivable
- the fair value of derivative assets
- notes receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At June 30, 2014 we had not incurred any significant credit losses and had no significant amounts past due or impaired. We had a credit risk concentration of $211 million with one counterparty at June 30, 2014 (December 31, 2013 - $240 million). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

We have significant credit and performance exposure to financial institutions because 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.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, our exposure to changes in currency exchange rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

Average exchange rate - U.S. to Canadian dollars

second quarter 2014	1.09
second quarter 2013	1.03

The impact of changes in the value of the U.S. dollar on our U.S. dollar-denominated operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below.

Significant U.S. dollar-denominated amounts

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$)	**2014**	2013	**2014**	2013
U.S. and International Natural Gas Pipelines comparable EBIT	**140**	101	**351**	301
U.S. Liquids Pipelines comparable EBIT	**133**	95	**262**	189
U.S. Power comparable EBIT	**61**	57	**120**	96
Interest expense on U.S. dollar-denominated long-term debt	**(216)**	(185)	**(423)**	(373)
Capitalized interest on U.S. capital expenditures	**43**	49	**95**	93
U.S. non-controlling interests and other	**(53)**	(39)	**(132)**	(87)
	108	78	**273**	219

NET INVESTMENT IN FOREIGN OPERATIONS

We hedge our 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. The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

	June 30, 2014		December 31, 2013	
(unaudited - millions of $)	Fair value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency swaps				
(maturing 2014 to 2019)[2]	**(186)**	**US 3,250**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts				
(maturing 2014)	**(14)**	**US 300**	(11)	US 850
	(200)	**US 3,550**	(212)	US 4,650

1 Fair values equal carrying values.
2 Net income in the three and six months ended June 30, 2014 included net realized gains of $5 million and $11 million, respectively, (2013 - gains of $7 million and $14 million, respectively) related to the interest component of cross-currency swaps.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of $)	June 30, 2014	December 31, 2013
Carrying value	**15,600 (US 14,600)**	14,200 (US 13,400)
Fair value	**18,200 (US 17,100)**	16,000 (US 15,000)

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

(unaudited - millions of $)	June 30, 2014	December 31, 2013
Other current assets	**5**	5
Intangible and other assets	**1**	—
Accounts payable and other	**(57)**	(50)
Other long-term liabilities	**(149)**	(167)
	(200)	(212)

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 our normal purchase and 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.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data 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 financial instruments.

Certain non-derivative financial instruments including 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 equal their fair value due to the nature of the item or the short time to maturity.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in OCI in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

Derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

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 us. 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.

Fair value of derivative instruments
The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses current market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives have 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.

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

(unaudited - millions of $)	June 30, 2014	December 31, 2013
Other current assets	**354**	395
Intangible and other assets	**127**	112
Accounts payable and other	**(404)**	(357)
Other long-term liabilities	**(236)**	(255)
	(159)	(105)

The effect of derivative instruments on the consolidated statement of income
The following summary does not include hedges of our net investment in foreign operations.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	2014	2013	2014	2013
Derivative instruments held for trading[1]				
Amount of unrealized gains/(losses) in the period				
Power	**6**	5	**15**	(3)
Natural gas	**(14)**	(21)	**(21)**	(12)
Foreign exchange	**25**	(10)	**23**	(16)
Amount of realized (losses)/gains in the period				
Power	**(3)**	(29)	**(31)**	(36)
Natural gas	**(4)**	(5)	**46**	(7)
Foreign exchange	**(1)**	(6)	**(18)**	(7)
Derivative instruments in hedging relationships[2,3]				
Amount of realized gains/(losses) in the period				
Power	**(4)**	(84)	**188**	(11)
Natural gas	**—**	(1)	**—**	(1)
Interest	**1**	2	**2**	4

1 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 held for trading derivative instruments are included net in interest expense and interest income and other, respectively.
2 At June 30, 2014, all hedging relationships were designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $5 million (2013 - $7 million) and a notional amount of US$300 million (2013 - US$200 million). For the three and six months ended June 30, 2014, net realized gains on fair value hedges were $2 million and $3 million, respectively (2013 - $2 million and $4 million, respectively) and were included in interest expense. For the three and six months ended June 30, 2014 and 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

3 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. For the three and six months ended June 30, 2014 and 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 components of the Condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2014**	**2013**	**2014**	**2013**
Change in fair value of derivative instruments recognized in OCI (effective portion)				
Power	**(7)**	(70)	**34**	(34)
Natural gas	**(1)**	—	**(1)**	—
Foreign exchange	**—**	2	**10**	4
Interest	**(1)**	—	**(1)**	—
	(9)	(68)	**42**	(30)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Power[2]	**(1)**	12	**(109)**	1
Natural gas	**2**	2	**2**	2
Interest	**3**	4	**8**	8
	4	18	**(99)**	11
Gains/(losses) on derivative instruments recognized in earnings (ineffective portion)				
Power	**3**	(2)	**(10)**	(7)
	3	(2)	**(10)**	(7)

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 condensed consolidated statement of income.

Credit risk related contingent features of derivative instruments
Derivatives contracts often contain financial assurance provisions that may require us to provide collateral if a credit risk related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade).

Based on contracts in place and market prices at June 30, 2014, the aggregate fair value of all derivative contracts with credit risk related contingent features that were in a net liability position was $17 million (December 31, 2013 - $16 million), with collateral provided in the normal course of business of nil (December 31, 2013 – nil). If the credit risk related contingent features in these agreements had been triggered on June 30, 2014, we would have been required to provide collateral of $17 million (December 31, 2013 - $16 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We feel we have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Other information

CONTROLS AND PROCEDURES
Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at June 30, 2014, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in second quarter 2014 that had or are likely to have a material impact on our internal control over financial reporting, other than noted below.

Effective January 1, 2014, management implemented an ERP system. As a result of the ERP system, certain processes supporting our internal control over financial reporting have changed. Management will continue to monitor the effectiveness of these processes going forward.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES
When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected

by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. You can find a summary of our critical accounting estimates in our 2013 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2013 other than described below. You can find a summary of our significant accounting policies in our 2013 Annual Report.

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. There was no material impact on our 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 effective prospectively from January 1, 2014 and will be applied for all applicable transactions after that date.

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 our 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. We do not expect the adoption of this new standard to have a material impact on our 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. We are currently evaluating the impact of the adoption of this ASU and have not yet determined the effect on our consolidated financial statements.

Reconciliation of non-GAAP measures

(unaudited - millions of $)	three months ended June 30 2014	three months ended June 30 2013	six months ended June 30 2014	six months ended June 30 2013
EBITDA	**1,279**	1,125	**2,664**	2,344
Cancarb gain on sale	**(108)**	—	**(108)**	—
Niska contract termination	**41**	—	**41**	—
NEB decision - 2012	**—**	—	**—**	(55)
Non-comparable risk management activities affecting EBITDA	**5**	18	**16**	22
Comparable EBITDA	**1,217**	1,143	**2,613**	2,311
Comparable depreciation and amortization	**(399)**	(356)	**(792)**	(710)
Comparable EBIT	**818**	787	**1,821**	1,601
Other income statement items				
Comparable interest expense	**(305)**	(268)	**(591)**	(539)
Comparable interest income and other	**39**	8	**41**	36
Comparable income tax expense	**(162)**	(131)	**(385)**	(289)
Net income attributable to non-controlling interests	**(31)**	(18)	**(83)**	(43)
Preferred share dividends	**—**	(5)	**(2)**	(11)
Comparable earnings	**359**	373	**801**	755
Specific items (net of tax):				
Cancarb gain on sale	**99**	—	**99**	—
Niska contract termination	**(31)**	—	**(31)**	—
NEB decision - 2012	**—**	—	**—**	84
Part VI.I income tax adjustment	**—**	25	**—**	25
Risk management activities[1]	**16**	(17)	**6**	(25)
Net income attributable to common shares	**443**	381	**875**	839
Comparable depreciation and amortization	**(399)**	(356)	**(792)**	(710)
Specific item:				
NEB decision - 2012	**—**	—	**—**	(13)
Depreciation and amortization	**(399)**	(356)	**(792)**	(723)
Comparable interest expense	**(305)**	(268)	**(591)**	(539)
Specific item:				
NEB decision - 2012	**—**	—	**—**	(1)
Interest expense	**(305)**	(268)	**(591)**	(540)
Comparable interest income and other	**39**	8	**41**	36
Specific items:				
NEB decision - 2012	**—**	—	**—**	1
Risk management activities[1]	**25**	(9)	**23**	(15)
Interest income and other	**64**	(1)	**64**	22
Comparable income tax expense	**(162)**	(131)	**(385)**	(289)
Specific items:				
Cancarb gain on sale	**(9)**	—	(9)	—
Niska contract termination	**10**	—	10	—
Canadian restructuring proposal - 2012	**—**	—	—	42
Part VI.I income tax adjustment	**—**	25	—	25
NEB decision - 2012	**—**	—	**—**	—
Risk management activities[1]	**(4)**	10	**(1)**	12
Income tax expense	**(165)**	(96)	**(385)**	(210)

1 Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2014	2013	2014	2013
Canadian Power	**(2)**	(4)	**(2)**	(6)
U.S. Power	**(9)**	(18)	**(11)**	(17)
Natural Gas Storage	**6**	4	**(3)**	1
Foreign exchange	**25**	(9)	**23**	(15)
Income tax attributable to risk management activities	**(4)**	10	**(1)**	12
Total gains/(losses) from risk management activities	16	(17)	**6**	(25)

Comparable EBITDA and EBIT by business segment

three months ended June 30, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines[1]	Energy	Corporate	Total
EBITDA	**759**	**249**	**293**	**(22)**	**1,279**
Cancarb gain on sale	**—**	**—**	**(108)**	**—**	**(108)**
Niska contract termination	**—**	**—**	**41**	**—**	**41**
Non-comparable risk management activities affecting EBITDA	**—**	**—**	**5**	**—**	**5**
Comparable EBITDA	**759**	**249**	**231**	**(22)**	**1,217**
Comparable depreciation and amortization	**(263)**	**(54)**	**(77)**	**(5)**	**(399)**
Comparable EBIT	**496**	**195**	**154**	**(27)**	**818**

three months ended June 30, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines[1]	Energy	Corporate	Total
EBITDA	644	186	312	(17)	1,125
Non-comparable risk management activities affecting EBITDA	—	—	18	—	18
Comparable EBITDA	644	186	330	(17)	1,143
Comparable depreciation and amortization	(245)	(37)	(69)	(5)	(356)
Comparable EBIT	399	149	261	(22)	787

six months ended June 30, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines[1]	Energy	Corporate	Total
EBITDA	**1,607**	**490**	**627**	**(60)**	**2,664**
Cancarb gain on sale	**—**	**—**	**(108)**	**—**	**(108)**
Niska contract termination	**—**	**—**	**41**	**—**	**41**
Non-comparable risk management activities affecting EBITDA	**—**	**—**	**16**	**—**	**16**
Comparable EBITDA	**1,607**	**490**	**576**	**(60)**	**2,613**
Comparable depreciation and amortization	**(525)**	**(103)**	**(154)**	**(10)**	**(792)**
Comparable EBIT	**1,082**	**387**	**422**	**(70)**	**1,821**

six months ended June 30, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines[1]	Energy	Corporate	Total
EBITDA	1,445	365	585	(51)	2,344
NEB decision - 2012	(55)	—	—	—	(55)
Non-comparable risk management activities affecting EBITDA	—	—	22	—	22
Comparable EBITDA	1,390	365	607	(51)	2,311
Comparable depreciation and amortization	(485)	(74)	(143)	(8)	(710)
Comparable EBIT	905	291	464	(59)	1,601

1 Previously Oil Pipelines.

QUARTERLY RESULTS

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2014		2013				2012	
(unaudited - millions of $, except per share amounts)	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	2,234	2,884	2,332	2,204	2,009	2,252	2,089	2,126
Net income attributable to common shares	443	432	436	494	381	458	315	379
Comparable earnings	359	442	426	460	373	382	327	359
Share statistics								
Net income per common share - basic and diluted	$0.57	$0.57	$0.58	$0.66	$0.51	$0.62	$0.43	$0.51

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate. The causes of these fluctuations vary across our business segments.

In Natural Gas Pipelines, quarter-over-quarter revenues and net income from the Canadian regulated pipelines generally remain relatively stable during any fiscal year. Our U.S. natural gas pipelines are generally seasonal in nature with higher earnings in the winter months as a result of increased customer demands. Over the long term, however, results from both our Canadian and U.S. natural gas pipelines fluctuate because of:

- regulatory decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In second quarter 2014, comparable earnings excluded a $99 million after-tax gain on the sale of Cancarb Limited and a $31 million after-tax loss related to the termination of the Niska Gas Storage contract.

In second quarter 2013, comparable earnings excluded a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

In first quarter 2013, comparable earnings excluded $84 million of net income in 2013 related to 2012 from the NEB decision (RH-003-2011).

Condensed consolidated statement of income

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2014**	**2013**	**2014**	**2013**
Revenues				
Natural gas pipelines	**1,154**	1,031	**2,369**	2,188
Liquids pipelines	**366**	278	**725**	549
Energy	**714**	700	**2,024**	1,524
	2,234	2,009	**5,118**	4,261
Income from Equity Investments	**68**	153	**203**	246
Operating and Other Expenses				
Plant operating costs and other	**684**	648	**1,489**	1,289
Commodity purchases resold	**328**	283	**1,034**	659
Property taxes	**119**	106	**242**	215
Depreciation and amortization	**399**	356	**792**	723
Gain on sale of assets	**(108)**	—	**(108)**	—
	1,422	1,393	**3,449**	2,886
Financial Charges/(Income)				
Interest expense	**305**	268	**591**	540
Interest income and other	**(64)**	1	**(64)**	(22)
	241	269	**527**	518
Income before Income Taxes	**639**	500	**1,345**	1,103
Income Tax Expense				
Current	**23**	(36)	**82**	43
Deferred	**142**	132	**303**	167
	165	96	**385**	210
Net Income	**474**	404	**960**	893
Net income attributable to non-controlling interests	**31**	18	**83**	43
Net Income Attributable to Controlling Interests	**443**	386	**877**	850
Preferred share dividends	**—**	5	**2**	11
Net Income Attributable to Common Shares	**443**	381	**875**	839

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2014	2013	2014	2013
Net Income	**474**	404	**960**	893
Other Comprehensive Income, Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	**(190)**	225	**50**	336
Change in fair value of net investment hedges	**79**	(135)	**(48)**	(184)
Change in fair value of cash flow hedges	**(4)**	(44)	**27**	(23)
Reclassification to Net Income of gains and losses on cash flow hedges	**2**	11	**(60)**	7
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**5**	6	**9**	12
Other comprehensive income/(losses) on equity investments	**2**	(2)	**2**	(3)
Other comprehensive (loss)/income (Note 8)	**(106)**	61	**(20)**	145
Comprehensive Income	**368**	465	**940**	1,038
Comprehensive (loss)/income attributable to non-controlling interests	**(8)**	55	**88**	100
Comprehensive Income Attributable to Controlling Interests	**376**	410	**852**	938
Preferred share dividends	**—**	5	**2**	11
Comprehensive Income Attributable to Common Shares	**376**	405	**850**	927

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2014**	2013	**2014**	2013
Cash Generated from Operations				
Net income	**474**	404	**960**	893
Depreciation and amortization	**399**	356	**792**	723
Deferred income taxes	**142**	132	**303**	167
Income from equity investments	**(68)**	(153)	**(203)**	(246)
Distributed earnings received from equity investments	**84**	180	**254**	264
Employee post-retirement benefits funding lower than expense	**2**	11	**12**	26
Gain on sale of assets	**(108)**	—	**(108)**	—
Other	**(6)**	19	**7**	34
Decrease/(increase) in operating working capital	**208**	(127)	**82**	(335)
Net cash provided by operations	**1,127**	822	**2,099**	1,526
Investing Activities				
Capital expenditures	**(967)**	(1,109)	**(1,745)**	(2,038)
Equity investments	**(40)**	(39)	**(129)**	(71)
Acquisitions	**—**	(55)	**—**	(55)
Proceeds from sale of assets, net of transactions costs	**187**	—	**187**	—
Deferred amounts and other	**(94)**	(144)	**(117)**	(164)
Net cash used in investing activities	**(914)**	(1,347)	**(1,804)**	(2,328)
Financing Activities				
Dividends on common and preferred shares	**(340)**	(330)	**(669)**	(646)
Distributions paid to non-controlling interests	**(47)**	(30)	**(88)**	(59)
Advances (to)/from parent, net	**(683)**	36	**(683)**	111
Notes payable issued/(repaid), net	**225**	1,388	**(522)**	559
Long-term debt issued, net of issue costs	**16**	10	**1,380**	744
Repayment of long-term debt	**(205)**	(695)	**(982)**	(709)
Common shares issued, net of issue costs	**675**	—	**1,115**	499
Partnership units of subsidiary issued, net of issue costs	**—**	384	**—**	384
Preferred shares redeemed	**—**	—	**(200)**	—
Net cash (used in)/provided by financing activities	**(359)**	763	**(649)**	883
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(17)**	14	**16**	22
(Decrease)/increase in Cash and Cash Equivalents	**(163)**	252	**(338)**	103
Cash and Cash Equivalents				
Beginning of period	**720**	388	**895**	537
Cash and Cash Equivalents				
End of period	**557**	640	**557**	640

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2014	December 31, 2013
ASSETS			
Current Assets			
Cash and cash equivalents		**557**	895
Accounts receivable		**1,169**	1,165
Due from affiliates		**2,807**	2,721
Inventories		**252**	251
Other		**1,049**	845
		5,834	5,877
Plant, Property and Equipment,	net of accumulated depreciation of $18,551 and $17,851, respectively	**38,456**	37,606
Equity Investments		**5,719**	5,759
Regulatory Assets		**1,610**	1,735
Goodwill		**3,712**	3,696
Intangible and Other Assets		**2,216**	1,953
		57,547	56,626
LIABILITIES			
Current Liabilities			
Notes payable		**1,343**	1,842
Accounts payable and other		**2,335**	2,141
Due to affiliates		**842**	1,439
Accrued interest		**390**	389
Current portion of long-term debt		**1,518**	973
		6,428	6,784
Regulatory Liabilities		**233**	229
Other Long-Term Liabilities		**632**	656
Deferred Income Tax Liabilities		**4,890**	4,564
Long-Term Debt		**21,774**	21,892
Junior Subordinated Notes		**1,067**	1,063
		35,024	35,188
EQUITY			
Common shares, no par value		**16,320**	15,205
Issued and outstanding:	June 30, 2014 - 779 million shares		
	December 31, 2013 - 757 million shares		
Preferred shares		**—**	194
Additional paid-in capital		**429**	431
Retained earnings		**5,320**	5,125
Accumulated other comprehensive loss (Note 8)		**(959)**	(934)
Controlling Interests		**21,110**	20,021
Non-controlling interests		**1,413**	1,417
		22,523	21,438
		57,547	56,626

Contingencies and Guarantees (Note 11)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	six months ended June 30	
(unaudited - millions of Canadian $)	**2014**	**2013**
Common Shares		
Balance at beginning of period	**15,205**	14,306
Shares issued on exercise of stock options	**1,115**	499
Balance at end of period	**16,320**	14,805
Preferred Shares		
Balance at beginning of period	**194**	389
Redemption of preferred shares	**(194)**	—
Balance at end of period	**—**	389
Additional Paid-In Capital		
Balance at beginning of period	**431**	400
Dilution impact from TC PipeLines, LP units issued	**—**	29
Redemption of preferred shares	**(6)**	—
Other	**4**	3
Balance at end of period	**429**	432
Retained Earnings		
Balance at beginning of period	**5,125**	4,657
Net income attributable to controlling interests	**877**	850
Common share dividends	**(680)**	(650)
Preferred share dividends	**(2)**	(11)
Balance at end of period	**5,320**	4,846
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(934)**	(1,448)
Other comprehensive (loss)/income	**(25)**	88
Balance at end of period	**(959)**	(1,360)
Equity Attributable to Controlling Interests	**21,110**	19,112
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,417**	1,036
Net income attributable to non-controlling interests		
TC PipeLines, LP	**74**	36
Portland	**9**	7
Other comprehensive income attributable to non-controlling interests	**5**	57
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**—**	384
Decrease in TCPL's ownership	**—**	(47)
Distributions to non-controlling interests	**(90)**	(59)
Foreign exchange and other	**(2)**	9
Balance at end of period	**1,413**	1,423
Total Equity	**22,523**	20,535

See accompanying notes to the condensed consolidated financial statements.

Notes to condensed consolidated financial statements (unaudited)

1. Basis of presentation

These condensed consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TCPL's annual audited consolidated financial statements for the year ended December 31, 2013. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TCPL's 2013 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2013 audited consolidated financial statements included in TCPL's 2013 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's Natural Gas Pipelines segment due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

USE OF ESTIMATES AND JUDGEMENTS

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 judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the consolidated financial statements for the year ended December 31, 2013, except as described in Note 2, Changes in accounting policies.

2. Changes in accounting policies

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. 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 effective prospectively from January 1, 2014 and will be applied for all applicable transactions after that date.

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.

3. Segmented information

three months ended June 30	**Natural Gas Pipelines**		**Liquids Pipelines**[1]		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Revenues	**1,154**	1,031	**366**	278	**714**	700	**—**	—	**2,234**	2,009
Income from equity investments	**37**	29	**—**	—	**31**	124	**—**	—	**68**	153
Plant operating costs and other	**(348)**	(339)	**(100)**	(82)	**(214)**	(210)	**(22)**	(17)	**(684)**	(648)
Commodity purchases resold	**—**	—	**—**	—	**(328)**	(283)	**—**	—	**(328)**	(283)
Property taxes	**(84)**	(77)	**(17)**	(10)	**(18)**	(19)	**—**	—	**(119)**	(106)
Depreciation and amortization	**(263)**	(245)	**(54)**	(37)	**(77)**	(69)	**(5)**	(5)	**(399)**	(356)
Gain on sale of assets	**—**	—	**—**	—	**108**	—	**—**	—	**108**	—
Segmented earnings	**496**	399	**195**	149	**216**	243	**(27)**	(22)	**880**	769
Interest expense									**(305)**	(268)
Interest income and other									**64**	(1)
Income before income taxes									**639**	500
Income tax expense									**(165)**	(96)
Net income									**474**	404
Net income attributable to non-controlling interests									**(31)**	(18)
Net income attributable to controlling interests									**443**	386
Preferred share dividends									**—**	(5)
Net income attributable to common shares									**443**	381

1 Previously Oil Pipelines.

six months ended June 30	Natural Gas Pipelines		Liquids Pipelines[1]		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Revenues	**2,369**	2,188	**725**	549	**2,024**	1,524	**—**	—	**5,118**	4,261
Income from equity investments	**89**	69	**—**	—	**114**	177	**—**	—	**203**	246
Plant operating costs and other	**(681)**	(657)	**(201)**	(161)	**(547)**	(420)	**(60)**	(51)	**(1,489)**	(1,289)
Commodity purchases resold	**—**	—	**—**	—	**(1,034)**	(659)	**—**	—	**(1,034)**	(659)
Property taxes	**(170)**	(155)	**(34)**	(23)	**(38)**	(37)	**—**	—	**(242)**	(215)
Depreciation and amortization	**(525)**	(498)	**(103)**	(74)	**(154)**	(143)	**(10)**	(8)	**(792)**	(723)
Gain on sale of assets	**—**	—	**—**	—	**108**	—	**—**	—	**108**	—
Segmented earnings	**1,082**	947	**387**	291	**473**	442	**(70)**	(59)	**1,872**	1,621
Interest expense									**(591)**	(540)
Interest income and other									**64**	22
Income before income taxes									**1,345**	1,103
Income tax expense									**(385)**	(210)
Net income									**960**	893
Net income attributable to non-controlling interests									**(83)**	(43)
Net income attributable to controlling interests									**877**	850
Preferred share dividends									**(2)**	(11)
Net income attributable to common shares									**875**	839

1 Previously Oil Pipelines.

TOTAL ASSETS

(unaudited - millions of Canadian $)	June 30, 2014	December 31, 2013
Natural Gas Pipelines	**25,406**	25,165
Liquids Pipelines[1]	**14,189**	13,253
Energy	**13,580**	13,747
Corporate	**4,372**	4,461
	57,547	56,626

1 Previously Oil Pipelines.

4. Asset disposition

The sale of Cancarb Limited and its related power generation facility was completed on April 15, 2014 for aggregate gross proceeds of $190 million. TCPL recognized a gain on the sale of $108 million ($99 million after tax) for the three and six months ended June 30, 2014. This gain has been presented separately on the consolidated statement of income.

5. Income taxes

At June 30, 2014, the total unrecognized tax benefit of uncertain tax positions was approximately $15 million (December 31, 2013 - $19 million). TCPL recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three and six months ended June 30, 2014 is $1 million and nil, respectively, of income for the reversal of interest expense and nil for penalties (June 30, 2013 - nil and $1 million, respectively, of interest expense and nil for penalties). At June 30, 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 for penalties).

The effective tax rates for the six-month periods ended June 30, 2014 and 2013 were 29 per cent and 19 per cent, respectively. The higher effective tax rate in 2014 compared to 2013 was primarily the result of the impact of the 2013 NEB decision (RH-003-2011), changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines, partially offset by the disposition of Cancarb Limited in 2014.

6. Long-term debt

In the three and six months ended June 30, 2014, TCPL capitalized interest related to capital projects of $63 million and $142 million, respectively (2013 - $60 million and $115 million, respectively).

LONG-TERM DEBT ISSUED

Amount (unaudited - millions of $)	Type	Maturity date	Interest rate	Date issued
US$1,250	Senior unsecured notes	March 1, 2034	4.625%	February 2014

LONG-TERM DEBT RETIRED

Amount (unaudited - millions of Canadian $)	Type	Retirement date	Interest rate
$450	Medium term notes	January 2014	5.65%
$300	Medium term notes	February 2014	5.05%
$125	Debenture	June 2014	11.10%
$53	Debenture	June 2014	11.20%

7. Equity and share capital

COMMON SHARE ISSUANCE

In January 2014, we issued 9.1 million common shares to TransCanada Corporation (TransCanada) resulting in proceeds of $440 million.

In April 2014, we issued 13.3 million common shares to TransCanada resulting in proceeds of $675 million.

PREFERRED SHARE REDEMPTION

On March 5, 2014, TCPL redeemed all of the four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series Y at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends to the redemption date.

8. Other comprehensive income/(loss) and accumulated other comprehensive loss

Components of other comprehensive income/(loss) including non-controlling interests and the related tax effects are as follows:

three months ended June 30, 2014 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	**(140)**	**(50)**	**(190)**
Change in fair value of net investment hedges	**107**	**(28)**	**79**
Change in fair value of cash flow hedges	**(9)**	**5**	**(4)**
Reclassification to net income of gains and losses on cash flow hedges	**4**	**(2)**	**2**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**7**	**(2)**	**5**
Other comprehensive income on equity investments	**1**	**1**	**2**
Other comprehensive loss	**(30)**	**(76)**	**(106)**

three months ended June 30, 2013 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	170	55	225
Change in fair value of net investment hedges	(182)	47	(135)
Change in fair value of cash flow hedges	(68)	24	(44)
Reclassification to net income of gains and losses on cash flow hedges	18	(7)	11
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	7	(1)	6
Other comprehensive loss on equity investments	(3)	1	(2)
Other comprehensive (loss)/income	(58)	119	61

six months ended June 30, 2014 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	**51**	**(1)**	**50**
Change in fair value of net investment hedges	**(64)**	**16**	**(48)**
Change in fair value of cash flow hedges	**42**	**(15)**	**27**
Reclassification to net income of gains and losses on cash flow hedges	**(99)**	**39**	**(60)**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**13**	**(4)**	**9**
Other comprehensive income on equity investments	**1**	**1**	**2**
Other comprehensive (loss)/income	**(56)**	**36**	**(20)**

six months ended June 30, 2013 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investment in foreign operations	247	89	336
Change in fair value of net investment hedges	(248)	64	(184)
Change in fair value of cash flow hedges	(30)	7	(23)
Reclassification to net income of gains and losses on cash flow hedges	11	(4)	7
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	17	(5)	12
Other comprehensive loss on equity investments	(4)	1	(3)
Other comprehensive (loss)/income	(7)	152	145

The changes in accumulated other comprehensive loss by component are as follows:

three months ended June 30, 2014 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and OPEB plan adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at April 1, 2014	**(560)**	**(35)**	**(193)**	**(104)**	**(892)**
Other comprehensive loss before reclassifications[2]	**(72)**	**(4)**	**—**	**—**	**(76)**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**2**	**5**	**2**	**9**
Net current period other comprehensive (loss)/income	**(72)**	**(2)**	**5**	**2**	**(67)**
AOCI balance at June 30, 2014	**(632)**	**(37)**	**(188)**	**(102)**	**(959)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest losses of $39 million.
3 Gains 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 $9 million ($4 million, net of tax) at June 30, 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.

six months ended June 30, 2014 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and OPEB plan adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2014	(629)	(4)	(197)	(104)	(934)
Other comprehensive (loss)/income before reclassifications[2]	(3)	27	—	—	24
Amounts reclassified from accumulated other comprehensive loss[3]	—	(60)	9	2	(49)
Net current period other comprehensive (loss)/income	(3)	(33)	9	2	(25)
AOCI balance at June 30, 2014	(632)	(37)	(188)	(102)	(959)

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive (loss)/income before reclassifications on currency translation adjustments is net of non-controlling interest gains of $5 million.
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 $9 million ($4 million, net of tax) at June 30, 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 accumulated other comprehensive loss are as follows:

(unaudited - millions of Canadian $)	**Amounts reclassified from accumulated other comprehensive loss**[1] **three months ended June 30, 2014**	**six months ended June 30, 2014**	**Affected line item in the condensed consolidated statement of income**
Cash flow hedges			
Power and natural gas	(1)	107	Revenue (Energy)
Interest	(3)	(8)	Interest expense
	(4)	99	Total before tax
	2	(39)	Income tax expense
	(2)	60	Net of tax
Pension and other post-retirement plan adjustments			
Amortization of actuarial loss and past service cost [2]	(7)	(13)	Total before tax
	2	4	Income tax expense
	(5)	(9)	Net of tax
Equity Investments			
Equity income	(1)	(1)	Income from Equity Investments
	(1)	(1)	Income tax expense
	(2)	(2)	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.
2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 9 for additional detail.

9. Employee post-retirement benefits

The net benefit cost recognized for the Company's defined benefit pension plans and other post-retirement benefit plans is as follows:

	three months ended June 30				six months ended June 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	2014	2013	2014	2013	2014	2013	2014	2013
Service cost	**21**	22	**—**	—	**43**	41	**1**	1
Interest cost	**28**	23	**3**	2	**56**	47	**5**	4
Expected return on plan assets	**(34)**	(29)	**(1)**	(1)	**(69)**	(58)	**(1)**	(1)
Amortization of actuarial loss	**6**	6	**—**	—	**11**	15	**1**	1
Amortization of past service cost	**1**	1	**—**	—	**1**	1	**—**	—
Amortization of regulatory asset	**4**	8	**—**	1	**9**	15	**—**	1
Amortization of transitional obligation related to regulated business	**—**	—	**1**	1	**—**	—	**1**	1
Net benefit cost recognized	**26**	31	**3**	3	**51**	61	**7**	7

10. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, and loans and advances receivable. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At June 30, 2014, there were no significant amounts past due or impaired, and there were no significant credit losses during the period.

At June 30, 2014, the Company had a credit risk concentration of $211 million (December 31, 2013 - $240 million) due from one counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

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

(unaudited - millions of Canadian $)	June 30, 2014	December 31, 2013
Carrying value	**15,600 (US 14,600)**	14,200 (US 13,400)
Fair value	**18,200 (US 17,100)**	16,000 (US 15,000)

Derivatives designated as a net investment hedge

(unaudited - millions of Canadian $)	June 30, 2014 Fair Value[1]	June 30, 2014 Notional or principal amount	December 31, 2013 Fair value[1]	December 31, 2013 Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps				
(maturing 2014 to 2019)[2]	**(186)**	**US 3,250**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts				
(maturing 2014)	**(14)**	**US 300**	(11)	US 850
	(200)	**US 3,550**	(212)	US 4,650

1 Fair values equal carrying values.
2 Net income in the three and six months ended June 30, 2014 included net realized gains of $5 million and $11 million, respectively, (2013 - gains of $7 million and $14 million, respectively) related to the interest component of cross-currency swaps which is included in interest expense.

Balance sheet presentation of net investment hedges

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

(unaudited - millions of Canadian $)	June 30, 2014	December 31, 2013
Other current assets	**5**	5
Intangible and other assets	**1**	—
Accounts payable and other	**(57)**	(50)
Other long-term liabilities	**(149)**	(167)
	(200)	(212)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of the Company's notes receivables 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, accrued interest, due to affiliates and other long-term liabilities have carrying amounts that equal 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:

(unaudited - millions of Canadian $)	June 30, 2014 Carrying amount[1]	June 30, 2014 Fair value	December 31, 2013 Carrying amount[1]	December 31, 2013 Fair value
Notes receivable and other[1]	**196**	**235**	226	269
Available for sale assets[2]	**46**	**46**	47	47
Current and long-term debt[3,4]	**(23,292)**	**(27,819)**	(22,865)	(26,134)
Junior subordinated notes	**(1,067)**	**(1,111)**	(1,063)	(1,093)
	(24,117)	**(28,649)**	(23,655)	(26,911)

1 Notes receivable are included in other current assets and intangible and other assets on the condensed consolidated balance sheet.
2 Available for sale assets are included in intangible and other assets on the condensed consolidated balance sheet.

3 Long-term debt is recorded at amortized cost, except for US$300 million (December 31, 2013 - US$200 million) that is attributed to hedged risk and recorded at fair value.
4 Consolidated net income for the three and six months ended June 30, 2014 included gains of $1 million and losses of $5 million, respectively, (2013 - gains of $3 million and losses of $7 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$300 million of long-term debt at June 30, 2014 (December 31, 2013 - US$200 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Derivative instruments

Fair value of derivative instruments
The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses current 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.

Where possible, derivative instruments are designated as hedges, but 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 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:

(unaudited - millions of Canadian $)	June 30, 2014	December 31, 2013
Other current assets	**354**	395
Intangible and other assets	**127**	112
Accounts payable and other	**(404)**	(357)
Other long-term liabilities	**(236)**	(255)
	(159)	(105)

2014 derivative instruments summary

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

(unaudited - millions of Canadian $, unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	**$314**	**$51**	**$14**	**$5**
Liabilities	**($320)**	**($70)**	**($2)**	**($5)**
Notional values[3]				
Volumes[4]				
Purchases	**41,098**	**99**	**—**	**—**
Sales	**39,010**	**50**	**—**	**—**
U.S. dollars	**—**	**—**	**US 1,516**	**US 100**
Net unrealized gains/(losses) in the period[5]				
three months ended June 30, 2014	**$6**	**($14)**	**$25**	**$—**
six months ended June 30, 2014	**$15**	**($21)**	**$23**	**$—**
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2014	**($3)**	**($4)**	**($1)**	**$—**
six months ended June 30, 2014	**($31)**	**$46**	**($18)**	**$—**
Maturity dates[3]	**2014-2017**	**2014-2020**	**2014**	**2016**
Derivative instruments in hedging relationships[6,7]				
Fair values[2,3]				
Assets	**$86**	**$—**	**$—**	**$5**
Liabilities	**($35)**	**$—**	**$—**	**($2)**
Notional values[3]				
Volumes[4]				
Purchases	**10,102**	**—**	**—**	**—**
Sales	**6,034**	**—**	**—**	**—**
U.S. dollars	**—**	**—**	**—**	**US 450**
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2014	**($4)**	**$—**	**$—**	**$1**
six months ended June 30, 2014	**$188**	**$—**	**$—**	**$2**
Maturity dates[3]	**2014-2018**	**—**	**—**	**2015-2018**

1 All derivative instruments held for trading have been entered into for risk management purposes and 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 values equal carrying values.

3 As at June 30, 2014.

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

5 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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included 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 revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.

6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $5 million and a notional amount of US$300 million as at June 30, 2014. For the three and six months ended June 30, 2014, net realized gains on fair value hedges were $2 million and $3 million, respectively, and were included in interest expense. For the three and six months ended June 30, 2014, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three and six months ended June 30, 2014, there were no gains or losses included in net income for 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 our net investment in foreign operations.

(unaudited - millions of Canadian $, unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	$265	$73	$—	$8
Liabilities	($280)	($72)	($12)	($7)
Notional values[3]				
Volumes[4]				
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 period[5]				
three months ended June 30, 2013	$5	($21)	($10)	$—
six months ended June 30, 2013	($3)	($12)	($16)	$—
Net realized losses in the period[5]				
three months ended June 30, 2013	($29)	($5)	($6)	$—
six months ended June 30, 2013	($36)	($7)	($7)	$—
Maturity dates[3]	2014-2017	2014-2016	2014	2014-2016
Derivative instruments in hedging relationships [6,7]				
Fair values[2,3]				
Assets	$150	$—	$—	$6
Liabilities	($22)	$—	($1)	($1)
Notional values[3]				
Volumes[4]				
Purchases	9,758	—	—	—
Sales	6,906	—	—	—
U.S. dollars	—	—	US 16	US 350
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2013	($84)	($1)	$—	$2
six months ended June 30, 2013	($11)	($1)	$—	$4
Maturity dates[3]	2014-2018	—	2014	2015-2018

1 All derivative instruments held for trading have been entered into for risk management purposes and 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 values equal carrying values.

3 As at December 31, 2013.

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

5 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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.

6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $5 million and a notional amount of US$200 million as at December 31, 2013. Net realized gains on fair value hedges for the three and six months ended June 30, 2013 were $2 million and $4 million, respectively, and were included in interest expense. For the three and six months ended June 30, 2013, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three and six months ended June 30, 2013, there were no gains or losses included in net income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 8) related to derivatives in cash flow hedging relationships are as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, pre-tax)	2014	2013	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)				
Power	**(7)**	(70)	**34**	(34)
Natural gas	**(1)**	—	**(1)**	—
Foreign exchange	**—**	2	**10**	4
Interest	**(1)**	—	**(1)**	—
	(9)	(68)	**42**	(30)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Power[2]	**(1)**	12	**(109)**	1
Natural gas	**2**	2	**2**	2
Interest	**3**	4	**8**	8
	4	18	**(99)**	11
Gains/(losses) on derivative instruments recognized in earnings (ineffective portion)				
Power	**3**	(2)	**(10)**	(7)
	3	(2)	**(10)**	(7)

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 condensed 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 to 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 June 30, 2014 (unaudited - millions of Canadian $)	Gross derivative instruments presented on the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Power	**400**	**(317)**	**83**
Natural gas	**51**	**(50)**	**1**
Foreign exchange	**20**	**(20)**	**—**
Interest	**10**	**(1)**	**9**
Total	**481**	**(388)**	**93**
Derivative - Liability			
Power	**(355)**	**317**	**(38)**
Natural gas	**(70)**	**50**	**(20)**
Foreign exchange	**(208)**	**20**	**(188)**
Interest	**(7)**	**1**	**(6)**
Total	**(640)**	**388**	**(252)**

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 June 30, 2014, the Company had provided cash collateral of $164 million and letters of credit of $18 million to its counterparties. The Company held $1 million in letters of credit on asset exposures at June 30, 2014.

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 (unaudited - millions of Canadian $)	**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
Total	507	(345)	162
Derivative - Liability			
Power	(302)	277	(25)
Natural gas	(72)	61	(11)
Foreign exchange	(230)	5	(225)
Interest	(8)	2	(6)
Total	(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, 2013, the Company had provided cash collateral of $67 million and letters of credit of $85 million to its counterparties. The Company held $11 million in cash collateral and $32 million in letters of credit on asset exposures at December 31, 2013.

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 June 30, 2014, the aggregate fair value of all derivative instruments with credit risk related contingent features that were in a net liability position was $17 million (December 31, 2013 - $16 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2013 - nil). If the credit risk related contingent features in these agreements were triggered on June 30, 2014, the Company would have been required to provide collateral of $17 million (December 31, 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 feels it 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 assets and liabilities recorded at fair value have been classified into three categories based on the 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 measured on a recurring basis using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long-term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate. 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 are based 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 is 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 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, are categorized as follows:

at June 30, 2014 (unaudited - millions of Canadian $, 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	**—**	**396**	**4**	**400**
Natural gas commodity contracts	**33**	**18**	**—**	**51**
Foreign exchange contracts	**—**	**20**	**—**	**20**
Interest rate contracts	**—**	**10**	**—**	**10**
Derivative instrument liabilities:				
Power commodity contracts	**—**	**(352)**	**(3)**	**(355)**
Natural gas commodity contracts	**(32)**	**(36)**	**(2)**	**(70)**
Foreign exchange contracts	**—**	**(208)**	**—**	**(208)**
Interest rate contracts	**—**	**(7)**	**—**	**(7)**
Non-derivative financial instruments:				
Available for sale assets	**—**	**46**	**—**	**46**
	1	**(113)**	**(1)**	**(113)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the six months ended June 30, 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 (unaudited - millions of Canadian $, 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:

	Derivatives[1]			
	three months ended June 30		**six months ended June 30**	
(unaudited - millions of Canadian $, pre-tax)	**2014**	**2013**	**2014**	**2013**
Balance at beginning of period	**1**	1	**1**	(2)
Settlements	**—**	1	**—**	1
Transfers out of Level III	**—**	(1)	**—**	(1)
Total losses included in net income	**(2)**	—	**(2)**	—
Total (losses)/gains included in OCI	**—**	(1)	**—**	2
Balance at end of period	**(1)**	—	**(1)**	—

1 For the three and six months ended June 30, 2014, energy revenues include unrealized losses attributed to derivatives in the Level III category that were still held at the reporting date of $2 million (2013 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $4 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at June 30, 2014.

11. Contingencies and guarantees

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 delivery 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:

		at June 30, 2014		at December 31, 2013	
(unaudited - millions of Canadian $)	Term	Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Bruce Power	ranging to 2019[2]	**674**	**7**	740	8
Other jointly owned entities	ranging to 2040	**64**	**10**	51	10
		738	**17**	791	18

1 TCPL's share of the potential estimated current or contingent exposure.
2 Except for one guarantee with no termination date.

12. Related Party Transactions

The following amounts are included in due from affiliates:

		2014		2013	
(unaudited - millions of Canadian $)	Maturity Date	Outstanding June 30	Effective Interest Rate	Outstanding December 31	Effective Interest Rate
Discount Notes[1]	2014	**2,682**	**1.3%**	2,721	1.3%
Credit Facility[2]		**125**	**3.0%**	—	—
		2,807		2,721	

1 Interest on the discount notes is equivalent to current commercial paper rates.
2 This facility bears interest at the Royal Bank of Canada prime rate per annum.

In the three and six months ended June 30, 2014, interest income included $9 million and $17 million, respectively (June 30, 2013 - $10 million and $20 million, respectively) as a result of inter-corporate borrowing.

At June 30, 2014, accounts receivables included $45 million due from various affiliates of TCPL (December 31, 2013 - $43 million).

The following amounts are included in due to affiliates:

		2014		2013	
(unaudited - millions of Canadian $)	Maturity Date	Outstanding June 30	Effective Interest Rate	Outstanding December 31	Effective Interest Rate
Credit Facility[1]	2014	**842**	**3.8%**	865	3.8%
Credit Facility[2]		**—**	**3.0%**	574	3.0%
		842		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 the three and six months ended June 30, 2014, interest expense included $9 million and $21 million, respectively of interest (June 30, 2013 - $17 million and $32 million, respectively) charges as a result of inter-corporate borrowing.

At June 30, 2014, accounts payable included $8 million of interest payable to TransCanada (December 31, 2013 - $1 million).

The company made interest payments of $1 million and $14 million to TransCanada in the three and six months ended June 30, 2014, respectively (June 30, 2013 - $30 million and $38 million, respectively).