Management's discussion and analysis

February 11, 2013

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 year ended December 31, 2012. Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles (as defined in Part V of the Canadian Institute of Chartered Accountants Handbook), have been adjusted as necessary to be compliant with our accounting policies under United States generally accepted accounting principles (U.S. GAAP), which we adopted effective January 1, 2012.

This MD&A should be read with our accompanying December 31, 2012 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

Contents

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 the document are defined in the glossary on page 94.

All information is as of February 11, 2013 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
- 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 outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future 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 debt issuances 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 U.S. pipelines business
- 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
- labour, equipment and material costs
- access to capital markets
- cybersecurity
- interest and foreign exchange rates
- weather
- 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 U.S. Securities and Exchange Commission (SEC).

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

See *Supplementary information* beginning on page 152 for other consolidated financial information on TCPL for the last three years.

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

About our business

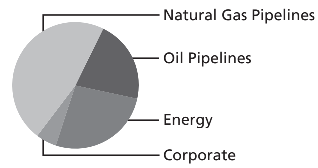
With over 60 years of experience, TCPL is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities. We are a wholly owned subsidiary of TransCanada Corporation (TransCanada).

THREE CORE BUSINESSES

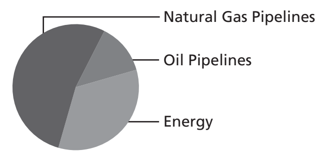
We operate our business in three segments – Natural Gas Pipelines, Oil Pipelines and Energy. We also have a non-operational corporate segment consisting of corporate and administrative functions that provide support and governance to our operational business segments.

Our $48 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 31 U.S. states, Mexico and three South American countries.

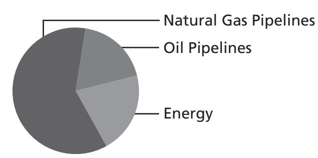
at December 31 (millions of $)	**2012**	**2011**	**% change**
Total assets			
Natural Gas Pipelines	**23,210**	23,161	-
Oil Pipelines	**10,485**	9,440	11%
Energy	**13,157**	13,269	(1%)
Corporate	**2,483**	2,196	13%
Total	**49,335**	48,066	3%



year ended December 31 (millions of $)	**2012**	**2011**	**% change**
Total revenue			
Natural Gas Pipelines	**4,264**	4,244	1%
Oil Pipelines	**1,039**	827	26%
Energy	**2,704**	2,768	(2%)
Corporate	**-**	-	-
Total	**8,007**	7,839	2%



year ended December 31 (millions of $)	**2012**	**2011**	**% change**
Comparable EBIT[1]			
Natural Gas Pipelines	**1,808**	1,952	(7%)
Oil Pipelines	**553**	457	21%
Energy	**620**	907	(32%)
Corporate	**(111)**	(100)	(11%)
Total	**2,870**	3,216	(11%)



1 Comparable EBIT is a non-GAAP measure – see page 12 for details.

Common shares outstanding – average

(millions)	
2012	738
2011	678
2010	662

as at February 6, 2013 **Common shares**	**Issued and outstanding**
	746 million

Preferred shares	**Issued and outstanding**
Series U	4 million
Series Y	4 million

A LONG-TERM STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

TCPL's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

Our strategy at a glance

- Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low-risk business model.
- Our pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings.
- In Energy, efficient, large-scale power generation facilities supply power markets through long-term power purchase and sale agreements and low-volatility shorter-term commercial arrangements. Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrate our commitment to clean, sustainable energy.

2 Commercially develop and build new asset investment programs

Our strategy at a glance

- We are developing quality projects under our current $12 billion capital program. These will contribute incremental earnings as our investments are placed in service.
- Our expertise in managing construction risks and maximizing capital productivity ensures a disciplined approach to quality, cost and schedule, resulting in superior service for our customers and quality returns to shareholders.
- As part of our growth strategy, we rely on this expertise and our regulatory, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.

3 Cultivate a focused portfolio of high quality development options

Our strategy at a glance

- We focus on pipelines and energy growth initiatives in core regions of North America.
- We are assessing opportunities to acquire energy infrastructure that complements our existing pipeline network and provides access to new supply and market regions.
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks are acceptable.

4 Maximize our competitive strengths

Our strategy at a glance

- We are continually developing competitive strengths in areas that directly drive long-term shareholder value.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give TCPL our competitive edge.

- Strong leadership: scale, presence, operating capabilities, strategy development; expertise in regulatory, legal and financing support.
- High quality portfolio: a low-risk business model that maximizes the full-life value of our long-life assets and commercial positions.
- Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.
- Financial expertise: excellent reputation for consistent financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizeable amounts of competitively priced capital to support our growth.
- Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors – both the upside and the risks – to build trust and support.

2012 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under U.S. GAAP because we believe they improve our ability to compare results between reporting periods, and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

See page 12 for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents.

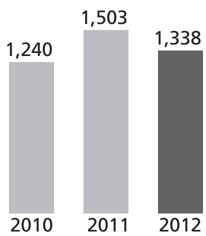
Highlights

Comparable EBITDA (earnings before interest, taxes, depreciation and amortization), comparable EBIT (earnings before interest and taxes), comparable earnings and funds generated from operations are all non-GAAP measures. See page 12 for more information.

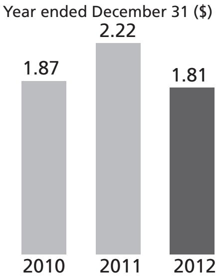
year ended December 31 (millions of $, except per share amounts)	**2012**	**2011**	**2010**
Income			
Revenue	**8,007**	7,839	6,852
Comparable EBITDA	**4,245**	4,544	3,686
Net income attributable to common shares	**1,338**	1,503	1,240
per common share – basic and diluted	**$1.81**	$2.22	$1.87
Comparable earnings	**1,369**	1,536	1,364
Operating cash flow			
Funds generated from operations	**3,259**	3,360	3,109
Decrease/(increase) in working capital	**287**	207	(292)
Net cash provided by operations	**3,546**	3,567	2,817
Investing activities			
Capital expenditures	**2,595**	2,513	4,376
Equity investments	**652**	633	597
Acquisitions, net of cash acquired	**214**	-	-
Balance sheet			
Total assets	**49,335**	48,066	46,595
Long-term debt	**18,913**	18,659	18,016
Junior subordinated notes	**994**	1,016	993
Preferred shares	**389**	389	389
Common shareholders' equity	**17,915**	17,543	14,988

Comparable earnings and net income

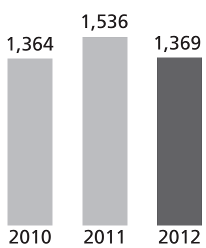
Net income attributable to common shares
Year ended December 31
(millions of $)



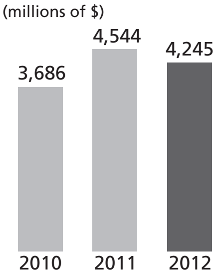
Net income per share – basic and diluted
Year ended December 31 ($)



Comparable earnings
Year ended December 31
(millions of $)



Comparable EBITDA
Year ended December 31
(millions of $)



Comparable earnings

Comparable earnings in 2012 were $167 million lower than 2011.

The decrease in comparable earnings was the result of:

- lower earnings from Western Power reflecting a full year of the Sundance A PPA force majeure
- lower equity income from Bruce Power because of increased outage days
- recording lower Canadian Mainline net income in 2012 which excluded incentive earnings and reflected a lower investment base
- lower earnings from Great Lakes which reflected lower revenues as a result of lower rates and uncontracted capacity
- lower earnings from ANR because of lower transportation and storage revenues, lower incidental commodity sales and higher operating costs
- lower earnings from U.S. Power due to lower realized prices, higher load serving costs and reduced water flows at the hydro facilities

These decreases were partially offset by:

- a full year of revenue from Guadalajara pipeline
- higher Keystone Pipeline System revenues primarily due to higher contracted volumes and a full year of earnings being recorded in 2012 compared to 11 months in 2011
- incremental earnings from Cartier Wind and Coolidge
- lower comparable interest expense mainly because of lower interest expense on amounts due to TransCanada, partially offset by new debt issuances in November 2011, March 2012 and August 2012
- higher comparable interest income and other, mainly because we realized higher gains on derivatives used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower comparable income taxes due to lower pre-tax earnings.

2011 comparable earnings were $172 million higher than 2010 and comparable EBIT was $690 million higher than 2010 resulting from:

- higher Natural Gas Pipelines comparable EBIT increased because we placed Bison in service in January and Guadalajara in service in June 2011, general, administrative and support costs were lower, and business development spending was lower. This was partly offset by lower revenues from certain U.S. pipelines and the negative impact of a weaker U.S. dollar.
- higher Oil Pipelines comparable EBIT as we began recording earnings from the Keystone Pipeline System in February 2011
- higher Energy comparable EBIT because realized power prices at Western Power were higher, combined with a full year of earnings from Halton Hills and the start up of Coolidge. This was partly offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power
- higher comparable interest expense, mainly because:
  - we placed the Keystone Pipeline System and other new assets in service, which reduced capitalized interest
  - we issued U.S. dollar-denominated debt in June and September 2010, which increased interest expense
  - partly offset by the realization of gains on derivatives used to manage our exposure to rising interest rates and a weaker U.S. dollar reduced our U.S. dollar-denominated interest expense
- lower comparable interest income and other, mainly due to reduced gains on the derivatives we used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher comparable income taxes, because pre-tax earnings were higher and higher positive income tax adjustments in 2010 compared to 2011.

Net income attributable to common shares

Net income attributable to common shares in 2012 was $1,338 million (2011 – $1,503 million; 2010 – $1,240 million).

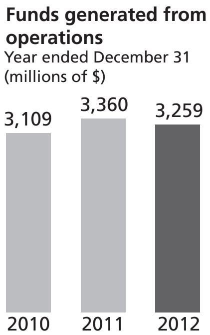
Net income includes comparable earnings discussed above as well as other specific items which are excluded from comparable earnings. The following specific items were recognized in net income in 2010 to 2012:

- a negative after-tax charge of $15 million ($20 million pre-tax) was included in net income following the Sundance A power purchase arrangement (PPA) arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011
- a negative after-tax charge of $127 million ($146 million pre-tax) was included in net income after we recorded a valuation provision against the loan to the Aboriginal Pipeline Group (APG) relating to the Mackenzie Gas Project (MGP). This charge was recorded in fourth quarter 2010.
- the impact of certain risk management activities each year. See page 12 for explanation of specific items in Non-GAAP measures.

Cash flow

Funds generated from operations

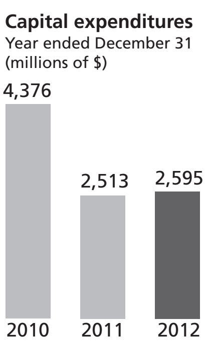
Funds generated from operations was three per cent lower this year primarily for the same reasons comparable earnings were lower, as described above.



Funds used in investing

Capital expenditures

We invested $2.6 billion in capital projects this year as part of our ongoing capital program. This program is a key part of our strategy to optimize the value of our existing assets and develop new, complementary assets in high demand areas.



Capital expenditures

year ended December 31, 2012 (millions of $)	
Natural Gas Pipelines	1,389
Oil Pipelines	1,145
Energy	24
Corporate	37

Equity investments and acquisitions

In 2012, we invested $0.7 billion into Bruce Power for capital projects which included the restart of Units 1 and 2 and the West Shift Plus life extension outage on Unit 3. We also spent $0.2 billion on the acquisition of the remaining 40 per cent interest in CrossAlta.

Balance sheet

We maintained a strong balance sheet while growing our total assets by over $3 billion since 2010. At December 31, 2012, common equity represented 45 per cent of our capital structure.

Dividends

Dividend reinvestment plan

Under our dividend reinvestment plan (DRP), eligible holders of TransCanada common or preferred shares and preferred shares of TCPL, can reinvest their dividends and make optional cash payments to buy TransCanada common shares.

Before April 28, 2011, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. Beginning with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market without discount. The increase in dividends paid on common shares (see below) is, in part, the result of this change combined with the impact of an annual five per cent increase in the dividend rate between 2010 and 2012.

Quarterly dividends on our common shares

The dividend declared for the quarter ending March 31, 2013 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 29, 2013.

Quarterly dividends on our preferred shares

Series U $0.70 (for the period ending April 30, 2013)

Series Y $0.70 (for the period ending May 1, 2013)

Cash dividends year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Common shares	**1,226**	1,163	1,088
Preferred shares	**22**	22	22

Refer to the Results section in each business segment and the Financial Condition section of this MD&A for further discussion of these highlights.

OUTLOOK

Earnings

We anticipate earnings in 2013 to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and fewer planned outage days at Bruce A
- higher New York capacity prices as a result of a September 2012 Federal Energy Regulatory Commission (FERC) order
- higher earnings from the Alberta System due to a higher investment base
- return to service of Sundance A in fall 2013
- acquisition of several Ontario Solar assets over the course of 2013 and 2014

A favourable decision by the National Energy Board (NEB) on the Canadian Mainline Business and Services Restructuring Proposal and 2012 and 2013 Mainline Final Tolls Application (Canadian Restructuring Proposal) would have a positive impact on 2013 earnings.

These increases in earnings will be partially offset by higher operating, maintenance and administration (OM&A), general and administrative and corporate and governance costs, lower EBIT from U.S. Pipelines and higher outage days at Bruce B.

EBIT

Natural Gas Pipelines

EBIT from the Natural Gas Pipelines segment in 2013 will be affected by regulatory decisions and the timing of those decisions, including decisions about the Canadian Restructuring Proposal. Earnings will also be affected by market conditions, which drive the level of demand and rates we are able to secure for our services. Today's North American natural gas market is characterized by strong natural gas production, low natural gas prices and low values for storage and transportation services, which we expect to have a negative impact on U.S. Pipelines revenue in 2013.

Until we receive the NEB's decision with respect to the Canadian Restructuring Proposal, earnings from the Canadian Mainline will continue to reflect the last approved rate of return on common equity (ROE) of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years. If the 2012 and 2013 tolls are approved as filed, earnings in 2013 will reflect a higher ROE equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent for 2012 and 2013. We also expect higher earnings from the Alberta System because of continued growth in the investment base.

Oil Pipelines

We expect 2013 EBIT from the Oil Pipelines segment to be consistent with 2012 as the Gulf Coast Project, currently under construction, is expected to be placed in service at the end of 2013.

Energy

We expect 2013 EBIT from the Energy segment to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and lower planned outage days at Bruce A
- a full year of operations from the Gros-Morne Wind farm, which was placed in service in fourth quarter 2012
- higher New York capacity prices as a result of the September 2012 FERC order affecting pricing rules for new entrants
- the return to service of Sundance A in fall 2013
- the acquisition of several Ontario Solar assets in 2013
- incremental earnings from acquiring the remaining 40 per cent interest in CrossAlta in late December 2012.

We expect these increases to be partially offset by higher outage days at Bruce B and higher Bruce A and B pension and staff costs.

Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be affected by fluctuations in commodity prices.

Consolidated capital expenditures, equity investments and acquisitions

We spent $3.5 billion on capital expenditures, equity investments and acquisitions in 2012 and expect to spend approximately $6.4 billion in 2013 primarily related to Keystone XL, Gulf Coast Project, Alberta System expansions, the Tamazunchale Extension project, the Topolobampo and Mazatlan pipelines in Mexico and maintenance projects on our natural gas pipelines.

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- comparable earnings
- comparable EBITDA
- comparable EBIT
- comparable interest expense
- comparable interest income and other
- comparable income taxes
- funds generated from operations.

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 interest and other financial charges, income taxes, 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 better measure of our performance and an effective tool for evaluating trends in each segment. 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 better measure of our consolidated operating cashflow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period. See page 6 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.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income taxes	income tax expense/(recovery)

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

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal and bankruptcy settlements, and
- 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.

Reconciliation of non-GAAP measures

year ended December 31 (millions of $, except per share amounts)	2012	2011	2010
Comparable EBITDA	**4,245**	4,544	3,686
Depreciation and amortization	**(1,375)**	(1,328)	(1,160)
Comparable EBIT	**2,870**	3,216	2,526
Other income statement items			
Comparable interest expense	**(997)**	(1,046)	(754)
Comparable interest income and other	**86**	60	94
Comparable income taxes	**(472)**	(565)	(387)
Net income attributable to non-controlling interests	**(96)**	(107)	(93)
Preferred share dividends	**(22)**	(22)	(22)
Comparable earnings	**1,369**	1,536	1,364
Specific items (net of tax)			
Sundance A PPA arbitration decision	**(15)**	-	-
Risk management activities[1]	**(16)**	(33)	3
Valuation provision for MGP	**-**	-	(127)
Net income attributable to common shares	**1,338**	1,503	1,240
Comparable interest expense	**(997)**	(1,046)	(754)
Specific item:			
Risk management activities[1]	**-**	2	-
Interest expense	**(997)**	(1,044)	(754)
Comparable interest income and other	**86**	60	94
Specific item:			
Risk management activities[1]	**(1)**	(5)	-
Interest income and other	**85**	55	94
Comparable income taxes	**(472)**	(565)	(387)
Specific item:			
Sundance A PPA arbitration decision	**5**	-	-
Risk management activities[1]	**6**	19	(4)
Valuation provision for MGP	**-**	-	19
Income taxes expense	**(461)**	(546)	(372)

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year ended December 31 (millions of $)	2012	2011	2010
Canadian Power	**4**	1	-
U.S. Power	**(1)**	(48)	2
Natural Gas Storage	**(24)**	(2)	5
Interest rate	**-**	2	-
Foreign exchange	**(1)**	(5)	-
Income taxes attributable to risk management activities	**6**	19	(4)
Total gains (losses) from risk management activities	**(16)**	(33)	3

EBITDA and EBIT by business segment

year ended December 31, 2012 (millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**2,741**	**698**	**903**	**(97)**	**4,245**
Depreciation and amortization	**(933)**	**(145)**	**(283)**	**(14)**	**(1,375)**
Comparable EBIT	**1,808**	**553**	**620**	**(111)**	**2,870**
year ended December 31, 2011 (millions of $)					
Comparable EBITDA	2,875	587	1,168	(86)	4,544
Depreciation and amortization	(923)	(130)	(261)	(14)	(1,328)
Comparable EBIT	1,952	457	907	(100)	3,216
year ended December 31, 2010 (millions of $)					
Comparable EBITDA	2,816	-	969	(99)	3,686
Depreciation and amortization	(913)	-	(247)	-	(1,160)
Comparable EBIT	1,903	-	722	(99)	2,526

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facitilities and other businesses across Canada, the U.S. and Mexico. We serve approximately 15 per cent of the U.S. demand and more than 80 per cent of the Canadian demand on a daily basis by connecting major natural gas supply basins and markets through:

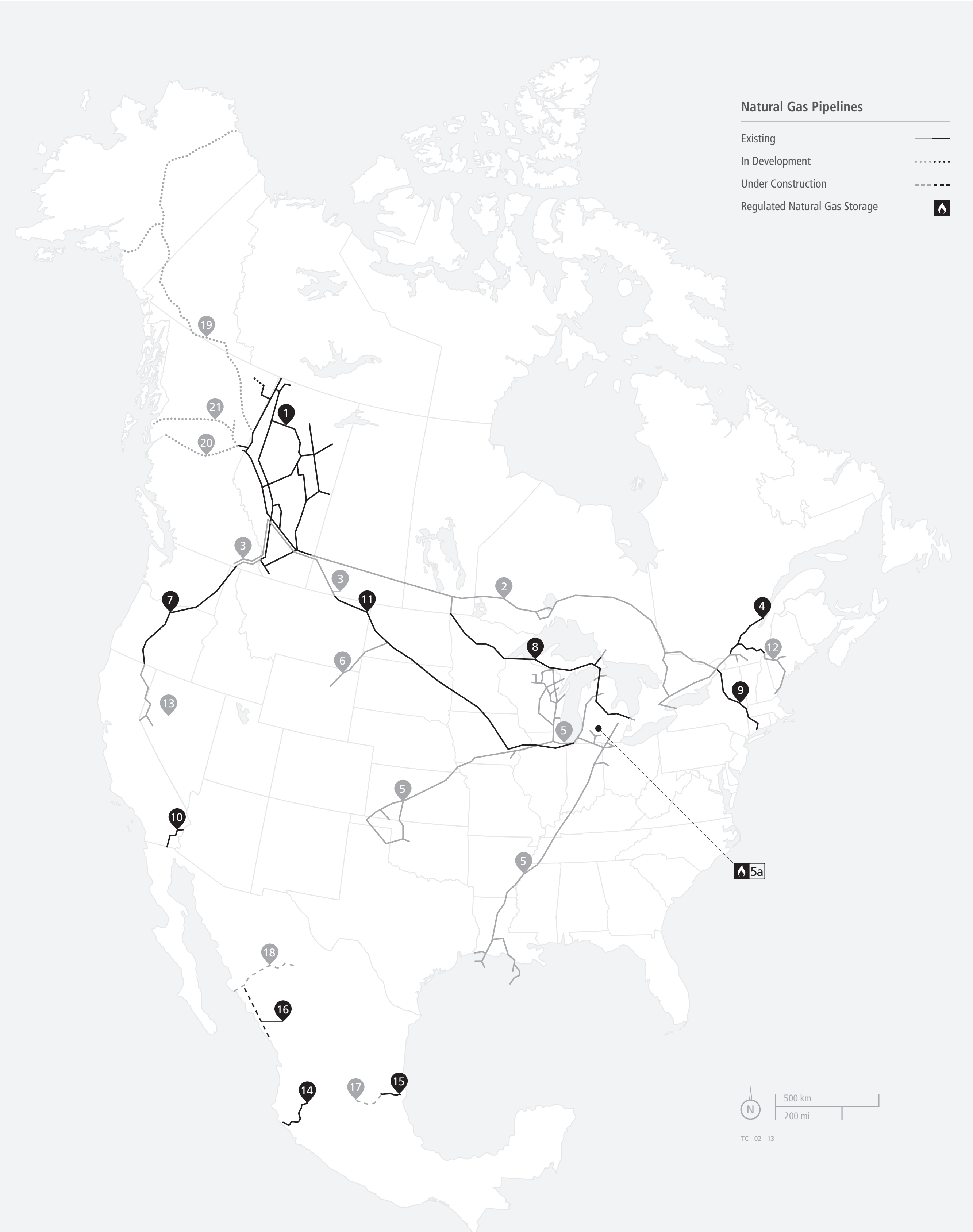
- wholly owned natural gas pipelines – 57,000 km (35,500 miles), and
- partially owned natural gas pipelines – 11,500 km (7,000 miles).

We have regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf, making us one of the largest providers of natural gas storage and related services in North America.

Strategy at a glance

Optimizing the value of our existing natural gas pipelines systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

We are also pursuing new pipeline projects to add incremental value to our business. Our key areas of focus include greenfield development opportunities, such as infrastructure for liquefied natural gas (LNG) exports and within Mexico, as well as other opportunities that connect natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies to market and play a critical role in meeting the increasing demand for natural gas in North America.


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
1
2
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5a
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500 km
200 mi
TC - 02 - 13

We are the operator of all of the following natural gas pipelines and storage assets except for Iroquois.

		length	description	effective ownership
	Canadian pipelines			
1	Alberta System	24,337 km (15,122 miles)	Gathers and transports natural gas within Alberta and Northeastern B.C., and connects with Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,101 km (8,762 miles)	Transports natural gas from the Alberta/Saskatchewan border to the Québec/Vermont border, and connects with other natural gas pipelines in Canada and the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. midwest, Pacific northwest, California and Nevada	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montreal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
	ANR			
5	Pipeline	16,656 km (10,350 miles)	Transports natural gas from producing fields in Texas and Oklahoma, from offshore and onshore regions of the Gulf of Mexico and from the U.S. midcontinent, for delivery mainly to Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	100%
5a	Storage	250 billion cubic feet	Provides regulated underground natural gas storage service from facilities located in Michigan	
6	Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
7	Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the Western Canada Sedimentary Basin (WCSB) and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
8	Great Lakes	3,404 km (2,115 miles)	Connects with ANR and the Canadian Mainline near Emerson, Manitoba, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 69.0 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	69%
9	Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%

		length	description	effective ownership
	U.S. pipelines			
10	North Baja	138 km (86 miles)	Transports natural gas between Ehrenberg, Arizona and Ogilby, California, and connects with a third-party natural gas system on the California/Mexico border. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	33.3%
11	Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 16.7 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	16.7%
12	Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	33.3%
	Mexican pipelines			
14	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo to Guadalajara in Mexico	100%
15	Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potos, Mexico	100%
	Under construction			
16	Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Mexico. Connects to the Topolobampo Pipeline Project	100%
17	Tamazunchale Pipeline Extension	235 km (146 miles)	Extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro, Mexico	100%
18	Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas from Chihuahua to Topolobampo, Mexico	100%
	In development			
19	Alaska Pipeline Project	2,737 km (1,700 miles)	To transport natural gas from Prudhoe Bay to Alberta, or from Prudhoe Bay to LNG facilities in south-central Alaska. We have an agreement with ExxonMobil to jointly advance the projects	
20	Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas-producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	
21	Prince Rupert Gas Transmission Project	750 km* (466 miles)	To deliver natural gas from North Montney gas producing region near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	

* Pipe lengths are estimates as final route is still under design

RESULTS

Natural Gas Pipelines results

Comparable EBITDA, comparable EBIT and EBIT are all non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Canadian Pipelines			
Canadian Mainline	**994**	1,058	1,054
Alberta System	**749**	742	742
Foothills	**120**	127	135
Other Canadian (TQM[1], Ventures LP)	**29**	34	33
Canadian Pipelines – comparable EBITDA	**1,892**	1,961	1,964
Depreciation and amortization[2]	**(715)**	(711)	(704)
Canadian Pipelines – comparable EBIT	**1,177**	1,250	1,260
U.S. and International (in US$)			
ANR	**254**	306	309
GTN[3]	**112**	131	171
Great Lakes[4]	**62**	101	109
TC PipeLines, LP[1,5]	**74**	85	81
Other U.S. pipelines (Iroquois[1], Bison[6], Portland[7])	**111**	111	61
International (Gas Pacifico/INNERGY[1], Guadalajara[8], Tamazunchale, TransGas[1])	**112**	77	42
General, administrative and support costs[9]	**(8)**	(9)	(31)
Non-controlling interests[10]	**161**	173	144
U.S. Pipelines and International – comparable EBITDA	**878**	975	886
Depreciation and amortization[2]	**(218)**	(214)	(203)
U.S. Pipelines and International – comparable EBIT	**660**	761	683
Foreign exchange	**-**	(7)	22
U.S. Pipelines and International – comparable EBIT (Cdn$)	**660**	754	705
Business Development comparable EBITDA and EBIT	**(29)**	(52)	(62)
Natural Gas Pipelines – comparable EBIT	**1,808**	1,952	1,903
Summary			
Natural Gas Pipelines – comparable EBITDA	**2,741**	2,875	2,816
Depreciation and amortization[2]	**(933)**	(923)	(913)
Natural Gas Pipelines – comparable EBIT	**1,808**	1,952	1,903
Specific items:			
Valuation provision for MGP[11]	**-**	-	(146)
Natural Gas Pipelines – EBIT	**1,808**	1,952	1,757

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.
2 Does not include depreciation and amortization from equity investments as these are already reflected in equity income.
3 Reflects our direct ownership interest of 75 per cent starting in May 2011 and 100 per cent prior to that date.
4 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 percent is held by TC PipeLines, LP.
5 Our ownership interest in TC PipeLines, LP went from 38.2 per cent to 33.3 per cent starting in May 2011. The TC PipeLines, LP results include our effective ownership since May 2011 of 8.3 per cent of both GTN and Bison.
6 Reflects our direct ownership of 75 per cent of Bison starting in May 2011 when 25 per cent was sold to TC PipeLines, LP, and 100 per cent since January 2011 when Bison was placed in service.
7 Represents our 61.7 per cent ownership interest.
8 Included as of June 2011.
9 General, administrative and support costs associated with some of our pipelines, including $17 million for the start up of Keystone in 2010.
10 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.
11 We recorded a valuation provision of $146 million in 2010 for our advances to the APG for MGP.

Canadian Pipelines

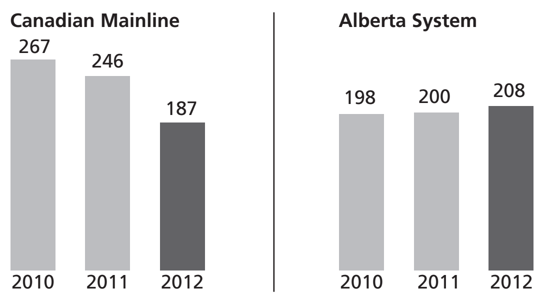
Comparable EBITDA and net income for our rate-regulated Canadian Pipelines are affected by our ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA but do not impact net income as they are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

Net income for the Canadian Mainline this year was $59 million lower than 2011 because there was no incentive earnings mechanism in place in 2012 and the average investment base was lower as annual depreciation outpaced our capital investment. Despite higher incentive earnings, 2011 net income was $21 million lower than 2010 because ROE was higher in 2010 (8.08 per cent in 2011 compared to 8.52 per cent in 2010), and the average investment base was also lower in 2011.

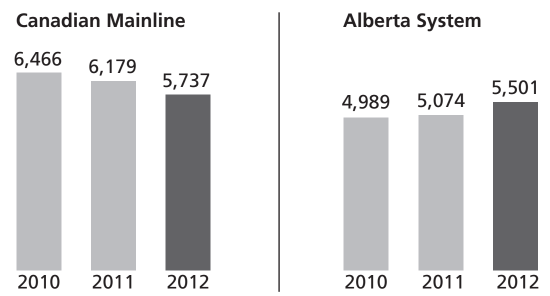
Net income for the Alberta System was $8 million higher than 2011 because of a growing investment base, as new natural gas supply in northeastern B.C. and western Alberta was developed and connected to the Alberta System. This was partially offset by lower incentive earnings. Net income in 2011 was $2 million higher than 2010, mainly due to a growing investment base.

Comparable EBITDA and EBIT for the Canadian pipelines reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis and, therefore, do not impact net income.

Net income
Year ended December 31 (millions of $)



Average investment base
Year ended December 31 (millions of $)



U.S. Pipelines and International

EBITDA for our U.S. operations is affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and other costs, and property taxes.

ANR is also affected by the contracting and pricing of its storage capacity and incidental commodity sales. ANR's pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of its business.

Comparable EBITDA for the U.S. and international pipelines was US$878 million in 2012, or US$97 million lower than 2011. This reflects the net effect of:

- lower revenue at Great Lakes because of lower rates and uncontracted capacity
- lower transportation and storage revenues at ANR, along with lower incidental commodity sales
- higher OM&A and other costs at ANR
- incremental earnings from the Guadalajara pipeline which started operations in June 2011.

Comparable EBITDA for U.S. and international pipelines was $975 million in 2011 which was $89 million higher than 2010. This was due to the net effect of:

- Bison starting operations in January 2011
- Guadalajara starting operations in June 2011
- lower general, administrative support costs in 2011
- lower revenues at Great Lakes and GTN in 2011.

Depreciation and amortization

Depreciation and amortization was $10 million higher in 2012 than in 2011, and was $10 million higher in 2011 than in 2010, mainly because Bison began operations in January 2011 and Guadalajara began operations in June 2011.

Business development

Business development expenses in 2012 were $23 million lower than last year because of lower expenses associated with the Alaska Pipeline Project. Expenses were $10 million lower in 2011 compared to 2010 mainly because the State of Alaska increased its business development reimbursement from 50 per cent to 90 per cent as of July 31, 2010.

OUTLOOK

Canadian Pipelines

Earnings

Earnings are affected most significantly by changes in investment base, ROE and capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

Until we receive the NEB's decision with respect to the Canadian Restructuring Proposal, earnings from the Canadian Mainline will continue to reflect the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent, and will exclude the opportunity for incentive earnings that have enhanced Canadian Mainline's earnings in recent years as no incentive arrangement is currently in place. If the 2012 and 2013 tolls are approved as filed, earnings in 2013 will reflect a higher ROE equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent for 2012 and 2013.

We expect the Alberta System's investment base to continue to grow as new natural gas supply in northeastern B.C. and western Alberta continues to be developed and is connected to it. We expect the growing investment base to have a positive impact on earnings in 2013.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

U.S. Pipelines

Earnings

Earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader macroeconomic conditions that might impact demand from certain customers or market segments. Currently, the North American natural gas market is characterized by low natural gas prices and low values for storage and transportation services, which we expect to have a negative impact on U.S. Pipelines revenue in 2013.

Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulators decisions.

Mexico Pipelines

2013 earnings are expected to be consistent with 2012 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital expenditures

We spent a total of $1.4 billion in 2012 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $1.9 billion in 2013 primarily on Alberta System expansion projects, the Tamazunchale Pipeline Extension, the Topolobampo and Mazatlan pipelines in Mexico, and maintenance projects on our natural gas pipelines. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines in North America that connects locations where gas is produced or interconnects with other pipelines connected to end customers such as local distribution companies, power generation facilities and other users. The network includes meter stations that record how much natural gas comes on the network and how much comes off at the delivery locations, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline, and the pipelines themselves that transport natural gas under high pressure.

Regulation, tolls and cost recovery

We are regulated in Canada by the NEB, in the U.S. by the FERC and in Mexico by the Comisión Reguladora de Energía or Energy Regulatory Commission (CRE). The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow recovery of costs to operate the network by collecting tolls, or payments, for services. These costs include OM&A costs, income and property taxes, interest on debt, depreciation expense to recover invested capital, and a return on the capital invested. The regulator reviews our costs to ensure they are prudent, and approves the tolls based on recovering these costs.

Within their respective jurisdictions, the FERC and CRE approve maximum transportation rates. These rates are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for investors. The pipeline may negotiate these rates with shippers.

Sometimes we and our shippers enter into agreements, or settlements, for tolls and cost recovery, which may include mutually beneficial performance incentives. The regulator must approve a settlement for it to be put into effect.

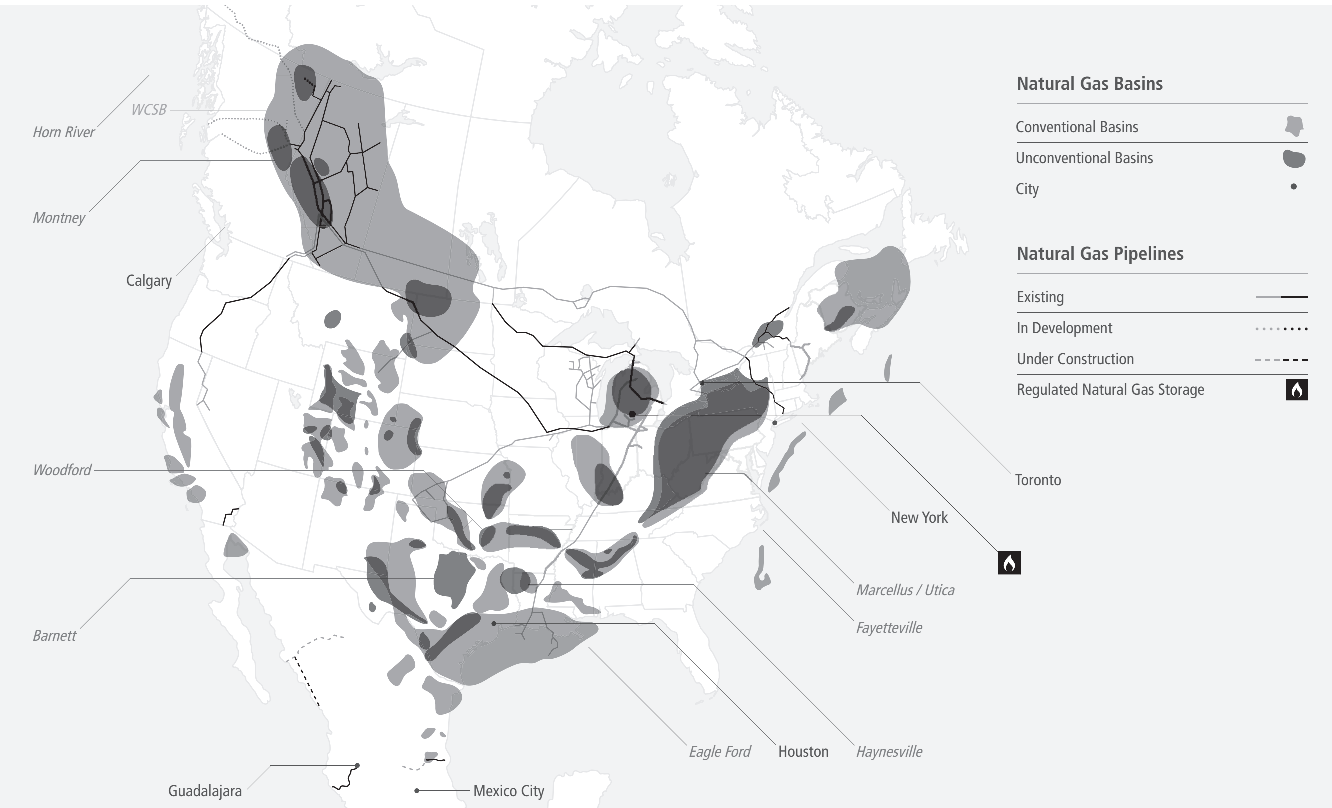
Generally, the Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover the variance between actual and expected revenues and costs in future years. The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower tolls if they consider returns to be too high. Our Mexico pipelines are also regulated and have approved tariffs, services and related rates. However, the contracts underpinning the facilities in Mexico are long-term negotiated rate contracts and not subject to further regulatory approval.

Business environment and strategic priorities

In this section, we discuss the environment in which we conduct our natural gas pipelines business, including our strategic priorities for our natural gas pipelines business.

The North American natural gas pipeline network has been developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies and changing demand.

We have a significant pipeline footprint in the WCSB and transport approximately 70 per cent of its production to markets within and outside of Alberta. Our pipelines also source natural gas, to a less significant degree, from the other major basins including the Appalachian, Rockies, Williston, Haynesville, Fayetteville, and Gulf of Mexico.



Increasing supply

The WCSB spans almost all of Alberta and extends into B.C., Saskatchewan, Yukon and Northwest Territories and is Canada's primary source of natural gas. The WCSB is currently estimated to have 125 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of almost 200 trillion cubic feet. The total WCSB resource base has more than doubled in the recent past with the advent of technology that can economically access unconventional gas plays in the basin. We expect production from the WCSB to decrease slightly in 2013 and then grow over the next decade.

The Montney and Horn River shale play formations in northeastern B.C. are also part of the WCSB and have recently become a significant source of natural gas. We expect production from these sources, currently 1.5 Bcf/d, to grow to approximately 5 Bcf/d by 2020, depending on natural gas prices and the economics of exploration and production.

The primary sources of natural gas in the U.S. are the U.S. shale plays, Gulf of Mexico and the Rockies. The U.S. shales are the biggest area of growth which we estimate will meet almost 50 per cent of the overall North American gas supply by 2020. Of the shale plays in the U.S, the Marcellus, Haynesville, Barnett, Eagle Ford and Fayetteville shale plays are the major supply sources.

The supply of natural gas in North America is forecast to increase significantly over the next decade (by approximately 15 Bcf/d by 2020), and is expected to continue to increase over the long term for several reasons:

- New technology, such as horizontal drilling in combination with multi-stage hydraulic fracturing or fracking, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing basins and opening up new producing regions, such as the Marcellus and Utica shale in the U.S. northeast, and the Montney and Horn River shale areas in northeastern B.C.
- These new technologies are also being applied to existing oil fields where further recovery of the resource is now possible. High oil prices, particularly compared to North American natural gas prices, has resulted in an increase in exploration and production of liquid-rich hydrocarbon basins. There is often associated gas in these plays (for example, the Bakken oil fields) which increases the overall gas supply for North America.

The development of shale gas basins that are located close to traditional existing markets, particularly in the U.S., has led to an increase in the number of supply choices and is changing traditional gas pipeline flow patterns. On some of our pipelines, such as the Canadian Mainline, ANR, and Great Lakes, there has been a reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, shorter-term contracts.

While the increase in supply, particularly in northeastern B.C., has created opportunities for us to build new pipeline infrastructure to move the natural gas to markets, the development of alternative supply sources in the U.S., and particularly in the U.S. northeast, has caused pipelines that have traditionally served markets in this area (including ours), to reconfigure their flow patterns from continental routes to more regional ones.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which have supported increasing demand and is expected to continue. Examples include:

- the use of natural gas in the development of the Alberta oil sands
- increased natural gas-fired power generation driven by conversion from coal
- industrial growth in both Canada and the U.S.
- increased exports to Mexico to fuel new power generation facilities
- increased use of natural gas used in petrochemical and industrial facilities in both Canada and the U.S.

Natural gas producers are also looking to sell natural gas to global markets, which would involve connecting natural gas supplies to new LNG export terminals proposed primarily along the west coast of B.C., and on the U.S. Gulf of Mexico coast. Assuming the receipt of all necessary regulatory and other approvals, these facilities are expected to become operational in the second half of this decade. The addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

More competition

Changes in supply and demand have resulted in growing pipeline infrastructure and increased competition for transportation services throughout North America. More pipeline capacity was added to the continental pipeline network between 2008 and 2011 than in any comparable time period in industry history, and gas supply areas that were once constrained, like the U.S. Rockies and east Texas, now have several paths to reach markets.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, as well as opportunities to connect new markets, while satisfying increasing demand for natural gas within existing markets.

We are also focused on adapting our existing assets to the changing gas flow dynamics.

The Canadian Mainline has traditionally sourced its natural gas primarily from the WCSB and delivered it to eastern markets. New supply located closer to the eastern markets has reduced demand for gas from the WCSB that, in turn, has reduced revenues from long haul transportation. As a result, overall tolls on the Mainline have increased and caused a reduction in the Canadian Mainline's competitive position. We are looking for opportunities to increase its market share in Canadian domestic markets, however, we expect to continue to face competition for both the eastern Canada and U.S. northeast markets. Our current application with the NEB seeks to restructure tolls on the Canadian Mainline to correspond with pipeline flow and usage patterns resulting from new supply and demand dynamics. The hearing on our application concluded in December 2012 and a decision is expected in late first quarter or early second quarter of 2013.

The Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in Western Canada to domestic and export markets. It faces competition for connection to supply, particularly in northeastern B.C., where the largest new source of natural gas has access to two existing competing pipelines. Connections to new supply and new or growing demand supports new capital expansions of the Alberta System. We expect supply in the WCSB to grow from its current level of approximately 14 Bcf/d to approximately 17 Bcf/d by 2020. The WCSB has an enormous remaining supply potential, but how much is produced, and how quickly, will be influenced by many factors, including transportation costs, the extent of the demand and local market price and basin-on-basin price differentials.

ANR has a very broad geographical footprint, with diverse market and supply access that includes 250 Bcf of natural gas storage, which is a major driver of ANR's revenues. ANR's supply of natural gas comes from many sources including the Gulf of Mexico, Mid-Continent, Rockies, Marcellus/ Utica and the WCSB. Demand served by this pipeline includes markets in Michigan, Wisconsin, Illinois, Indiana and Ohio. Many of ANR's supply and market regions are also served by competing interstate and intrastate natural gas pipelines.

ANR has demonstrated its adaptability to changing market dynamics by identifying opportunities and investing in its system to accommodate the market's demands for services that are counter to traditional flow patterns. This has resulted in increased bi-directional flows and shorter haul services in some of its supply and market areas.

Although the unseasonably warm winter weather and lack of storage demand negatively impacted ANR in 2012, we expect an increased demand for pipeline transportation broadly in the U.S. resulting in a positive impact to ANR because of the following factors:

- a return to average weather conditions
- the increase in gas-fired power generation due to coal switching to gas and coal plant retirements
- LNG exports from the Gulf of Mexico and growth in the industrial sector such as petrochemicals.

GTN is supplied with natural gas from the WCSB and the Rockies. It competes with other interstate pipelines providing natural gas transportation services to markets in the U.S. Pacific Northwest, California and Nevada. These markets also have access to supplies from natural gas basins in the Rocky Mountains and the U.S. Southwest. GTN has significant long term contracts and is currently operating under a rate settlement which started in January 2012 and expires at the end of December 2015. As a result, GTN's revenues are subject to variation primarily as a result of capacity sold above its current contracted amount.

Great Lakes competes for natural gas transportation customers with pipelines that transport gas from the WCSB and natural gas sourced in the U.S. Great Lakes has experienced significant non-renewals of its long haul capacity in the past few years and its contracts are for shorter terms than in the past. Great Lakes revenues were also negatively impacted in 2012 by a warm winter and historically high storage levels that decreased its throughput. Demand for Great Lakes capacity changes with seasonal market conditions and we expect a return to average winter weather will increase throughput due to storage demand. Great Lakes is required to file a rate case no later than November 1, 2013, and this provides the opportunity for rate and tariff changes in response to current market conditions.

We are continually assessing our existing natural gas pipelines assets, and have reviewed the possibility of converting existing infrastructure from gas service to crude oil. We received NEB approval in 2007 to convert one of our Canadian Mainline gas pipelines to crude oil service for the original Keystone project. We have determined that a further conversion of portions of the Canadian Mainline from natural gas to crude oil to serve eastern markets is both technically and economically feasible. The oil pipeline group is assessing the commercial interest in such a conversion.

We are also focused on capturing new opportunities resulting from the changing supply and demand dynamics. In 2012, we undertook the following new projects:

- we completed and placed in service approximately $650 million in pipeline projects to expand the Alberta System.
- we reached an agreement with Shell to build and operate the proposed $4 billion Coastal GasLink pipeline to move WCSB gas to Shell Canada Limited's proposed west coast LNG project near Kitimat, B.C.
- we were awarded $1.9 billion for new pipeline infrastructure projects to meet the growing demand for natural gas in Mexico
- we proposed a $1.0 billion to $1.5 billion expansion to the Alberta System in northeast B.C. to connect to both the Prince Rupert Gas Transmission Project and to additional North Montney supplies.

In January 2013, we were selected by Progress Energy Canada Ltd, to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission Project that will transport natural gas from northeastern B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C.

SIGNIFICANT EVENTS

Canadian Pipelines

Alberta System

This year we completed and placed in service approximately $650 million in pipeline projects to expand the Alberta System. This included completing the Horn River project in May, which extended the Alberta System into the Horn River shale play in B.C.

In 2012, the NEB approved approximately $640 million in additional expansions, including the Leismer-Kettle River Crossover project, a 30-inch, 77 km (46 mile) pipeline. This project will cost an estimated $160 million and is intended to increase capacity to meet demand in northeastern Alberta. As of December 31, approximately $330 million in additional projects were awaiting approval, including the $100 million Chinchaga Expansion and the $230 million Komie North project that would extend the Alberta System further into the Horn River area. On January 30, 2013, the NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of that project be approved, but denied the proposed Komie North Extension component. All applications awaiting approval as of the end of 2012 have now been addressed.

Canadian Mainline

An NEB hearing began in June 2012 to address our application to change the business structure and the terms and conditions of service for the Canadian Mainline, including tolls for 2012 and 2013. The hearing concluded in December 2012 and a decision is not expected until late first quarter or early second quarter 2013.

We received NEB approval in May to build new pipeline facilities to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. Supply began moving on November 1, 2012.

In response to requests to bring additional Marcellus shale gas into Canada, we held an additional open season for firm transportation service on the Canadian Mainline that ended in May 2012. We were able to accommodate an additional 50 MMcf/d from the Niagara meter station to Kirkwall effective November 1, 2012 with the potential for an additional 350 MMcf/d of incremental volumes for November 1, 2015 subject to finalizing precedent agreements with the interested parties.

Projects

Coastal GasLink

We were selected in June by Shell and its partners to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion pipeline will transport natural gas from the Montney gas-producing region near Dawson Creek, B.C. to LNG Canada's recently announced LNG export facility near Kitimat, B.C. The LNG Canada project is a joint venture led by Shell, with partners Korea Gas Corporation, Mitsubishi Corporation and PetroChina Company Limited. The approximate 650 km (404 mile) pipeline is expected to have an initial capacity of more than 1.7 Bcf/d and be placed in service toward the end of the decade, subject to a final investment decision to be made by LNG Canada subsequent to obtaining final regulatory approvals.

Prince Rupert Gas Transmission Project

We have been selected by Progress Energy Canada Ltd (Progress), to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission Project. This proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C., to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We expect to finalize definitive agreements with Progress in early 2013 leading to an in-service date in late 2018. A final investment decision to construct the project is expected to be made by Progress following final regulatory approvals.

Alberta System expansion projects

We continue to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. We have filed applications with the NEB to expand the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. In addition, we propose to further extend the Alberta System in northeast B.C. to connect both to the Prince Rupert Gas Transmission Project and to additional North Montney gas supplies. This new infrastructure will allow the Pacific Northwest LNG export facility, located on the west coast of B.C., to access both the North Montney supplies as well as other WCSB gas supply. Initial capital cost estimates are approximately $1 billion to $1.5 billion, with an initial in-service date targeted for the end of 2015. We have incremental firm commitments to transport approximately 3.4 Bcf/d from western Alberta and northeastern B.C. by 2015.

Tamazunchale Pipeline Extension Project

In February 2012, we signed a contract with Mexico's Comisión Federal de Electricidad (CFE) for the approximately $500 million Tamazunchale Pipeline Extension Project. The project, which is supported by a 25-year contract with CFE, is a 235 km (146 mile) 30 inch pipeline with a capacity of 630 MMcf/d. Engineering, procurement and construction contracts have all been signed and construction related activities have begun. We expect the pipeline to be in service in the first quarter of 2014.

Topolobampo Pipeline Project

In November, CFE also awarded us the Topolobampo pipeline, from Chihuahua to Topolobampo, Mexico. The project, which is supported by a 25 year contract with CFE, is a 530 km (329 mile) 30 inch pipeline with a capacity of 670 MMcf/d. We estimate total costs to be US$1 billion, and expect it to be in service in mid-2016.

Mazatlan Pipeline Project

In November, CFE also awarded us the Mazatlan pipeline, from El Oro to Mazatlan, Mexico. The project, which is also supported by a 25 year contract with CFE and interconnects with the Topolobampo project, is a 413 km (257 mile) 24 inch pipeline with a capacity of 200 MMcf/d. We estimate total costs to be US$400 million, and expect it to be in service in fourth quarter 2016.

Alaska Pipeline Project
We and the Alaska North Slope producers have agreed on a work plan to evaluate options to commercialize North Slope natural gas resources through an LNG option. We received approval in May from the State of Alaska to suspend and preserve our activities on the Alaska/Alberta route and focus on the LNG alternative, which allowed us to defer our obligation to file for a FERC certificate for the Alberta route beyond fall 2012 (our original deadline). In September 2012, we solicited interest in a natural gas pipeline as part of the LNG option and there were a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors in North America and Asia.

Regulatory filings

Canadian Pipelines
We filed a comprehensive restructuring proposal with the NEB in September 2011 for the Canadian Mainline. The proposal is intended to enhance the competitiveness of the Canadian Mainline and transportation from the WCSB, and includes a request for 2012 and 2013 tolls that align with the proposed changes to our business structure and the terms and conditions of service on the Canadian Mainline. The NEB established interim tolls for 2012 based on the approved 2011 final tolls. We do not expect a decision on the Canadian Restructuring Proposal until late first quarter or early second quarter 2013.

The current settlements for the Alberta and Foothills systems expired at the end of 2012. Final tolls for 2013 will be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Canadian Restructuring Proposal.

U.S. Pipelines
ANR Pipeline Company rates were established at the beginning of 1997. ANR can, but is not required to, file for new rates. The FERC issued orders in 2012 approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC, allowing TC Offshore LLC to operate these assets as a stand-alone interstate pipeline. TC Offshore LLC began commercial operations on November 1, 2012. ANR Storage Company secured a settlement with its shippers that the FERC approved on August 20, 2012. ANR Storage Company owns 56 Bcf of the total ANR storage capacity.

GTN has a FERC-approved settlement agreement for transportation rates that is effective from January 2012 to the end of December 2015. The GTN settlement includes a moratorium on the filing of future rate proceedings until December 2015. GTN is required to file for new rates to go into effect January 1, 2016.

Northern Border secured a final settlement agreement with its shippers that the FERC approved with an effective date of January 1, 2013. The settlement rates for long-haul transportation are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three-year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.

Great Lakes has a FERC-approved settlement agreement in place. It can file for new rates at any time, but must file no later than November 1, 2013.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 70 for information about general risks that affect the company as a whole.

WCSB supply for downstream connecting pipelines
Although we have diversified our sources of natural gas supply, many of our North American natural gas pipelines and transmission infrastructure assets depend on supply from the WCSB. There is competition for this supply from several downstream pipelines, demand within Alberta, and in the future, demand for proposed pipelines for LNG exports from the west coast of B.C. The WCSB has considerable reserves, but how much of it is actually produced will depend on many variables, including the price of gas, basin-on-basin

competition, downstream pipeline tolls, demand within Alberta and the overall value of the reserves, including liquids content.

Market access to other supply

We compete for market share with other natural gas pipelines. New supply areas being developed closer to traditional markets have reduced the competitiveness of our long haul pipelines, and may continue to do so. The long-term competitiveness of our pipeline systems will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition

We face competition from other pipeline companies seeking to connect similar supply and/or access to market. Most, if not all, long haul natural gas pipelines in North America are affected by the fundamental changes in flow dynamics resulting from new shale supply developments. The future success of new projects, such as connecting pipelines to LNG export facilities or development of Mexico gas pipeline infrastructure, is anticipated to be highly competitive.

Demand for pipeline capacity

Demand for a pipeline's capacity is ultimately the key driver that enables transportation services to be sold. Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Demand and supply in new locations often creates opportunities for new infrastructure, but it may also change flow patterns and potentially impact the utilization of existing assets. For example, the proposed LNG facilities on the west coast of B.C. have the potential to reduce demand for capacity on pipelines that transport WCSB supply to other markets. Our natural gas pipelines may be challenged to sell available transportation capacity as transportation contracts expire on our existing pipeline assets, as they have, for example, on the Great Lakes system. We expect our U.S. natural gas pipelines to become more exposed to the potential for revenue variability due to rapidly evolving supply dynamics, competition and trends toward shorter-term contracting by shippers.

Several factors influence demand for pipeline capacity:

- the price of natural gas is a key driver for development and exploration of the resource. The current low gas prices in North America may slow drilling activities which in turn diminishes production levels, particularly in dry gas fields where the extra revenue generated from the entrained liquids is not available.
- large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of the necessary pipeline infrastructure. Basin-on-basin competition impacts the extent and timing of a resource play's development, which in turn drives changes in demand for pipeline capacity.
- there is growing regulatory and public scrutiny over the environmental impacts of fracking. Changes in regulations that apply to fracking could impact the costs and pace of development of natural gas plays.
- growing pipeline infrastructure, changes in supply sources, and unutilized capacity on many pipelines have led to a contraction of regional basis differentials (the differences in market prices paid for natural gas between different gas receipt and delivery points), which has led to changes in the way many pipeline systems are being used. As a result, many pipeline companies are moving to restructure their business models, rate designs and services to adapt to the changing flow dynamics.

Regulatory risk

Decisions by regulators can have an impact on the approval, construction, operation and financial performance of our natural gas pipelines. We manage these risks through rate and facility applications and negotiated settlements, where possible. Public opinion about natural gas pipeline development can also have an impact on the regulatory approval process for new gas pipeline assets. We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business and work closely with our stakeholders in the development of the assets.

Operational

Keeping our pipelines operating is essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced revenue. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly, and repair or replace them whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Oil Pipelines

TCPL's Keystone Pipeline System connects Alberta crude oil supplies to significant U.S. refining markets in Illinois and Oklahoma. The system has a nominal design capacity of 591,000 Bbl/d and is 3,467 km (2,154 miles) long.

Our plan for Keystone XL creates an opportunity for us to transport growing North American crude oil supplies to market. Keystone XL will increase the total capacity of the Keystone Pipeline System to approximately 1.4 million Bbl/d and we have secured long-term, firm contracts in excess of 1.1 million Bbl/d.

The current construction of the Gulf Coast Project will connect the crude oil hub at Cushing, Oklahoma to the U.S. Gulf Coast with an initial capacity of up to 700,000 Bbl/d.

We recently announced the Grand Rapids Pipeline and Northern Courier Pipeline and our expansion of the Keystone Hardisty Terminal. These projects are giving us a competitive position in the growing intra-Alberta crude oil transportation market.

Strategy at a glance
With the increasing production of crude oil in Alberta, new crude oil discoveries in the U.S. and the growing demand for secure, reliable sources of energy, developing new crude oil pipeline capacity is essential.

We continue to focus on contracting and delivering growing North American crude oil supply to key U.S. markets, and are planning to expand our oil pipeline infrastructure by:

- building a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast (the Gulf Coast Project)
- adding batch accumulation and pipeline infrastructure at Hardisty, Alberta (Keystone Hardisty Terminal)
- building a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska (Keystone XL)
- building the Grand Rapids Pipeline to transport crude oil and diluent between the producing area in northern Alberta and the Edmonton/Heartland region and
- building the Northern Courier Pipeline to transport bitumen and diluent between the Fort Hills mine site and proposed Voyageur Upgrader, north of Fort McMurray, Alberta.

Our proposed conversion of a portion of the Canadian Mainline from natural gas to crude oil service would connect the eastern Canadian refining market to our oil pipeline infrastructure (Canadian Mainline conversion) and also gives us additional opportunities to expand our oil pipelines business.

Oil Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
Crude Oil Receipt Facility
29
27
25
26
28
22
23
24
N
500 km
200 mi
TC - 02 - 13

We are the operator of all of the following pipelines and properties.

		length	description	ownership
	Oil pipelines			
22	Keystone Pipeline System	3,467 km (2,154 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma	100%
	Under construction			
23	Cushing Marketlink	Crude oil receipt facilities	To transport crude oil from the Permian Basin producing region in western Texas to the U.S. Gulf Coast refining market on facilities that form part of the Gulf Coast Project	100%
24	Gulf Coast Project	780 km (485 miles)	To transport crude oil from the hub at Cushing, Oklahoma to the U.S. Gulf Coast refinery market. Includes the 76 km (47 mile) Houston Lateral pipeline	100%
25	Keystone Hardisty Terminal	Crude oil terminal	Crude oil terminal to be located at Hardisty, Alberta, providing Western Canadian producers with new crude oil batch accumulation tankage and pipeline infrastructure and access to the Keystone Pipeline System	100%
	In development			
26	Bakken Marketlink	Crude oil receipt facilities	To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
*	Canadian Mainline Conversion		Conversion of a portion of the Canadian Mainline natural gas pipeline system to crude oil service, which will transport crude oil between Hardisty, Alberta and markets in eastern Canada	100%
27	Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil between the producing area northwest of Fort McMurray and the Edmonton/Heartland market region. Project is a partnership with Phoenix Energy Holdings Limited (Phoenix)	50%
28	Keystone XL	1,897 km (1,179 miles)	Pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System to 1.4 million Bbl/d. Awaiting U.S. Presidential Permit decision	100%
29	Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader located north of Fort McMurray, Alberta.	100%

* Not shown on map

RESULTS

Comparable EBITDA, comparable EBIT and EBIT are all non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	2011[1]
Keystone Pipeline System	**712**	589
Oil Pipeline Business Development	**(14)**	(2)
Oil Pipelines – comparable EBITDA	**698**	587
Depreciation and amortization	**(145)**	(130)
Oil Pipelines – comparable EBIT	**553**	457
Comparable EBIT denominated as follows		
Canadian dollars	**191**	159
U.S. dollars	**363**	301
Foreign exchange	**(1)**	(3)
Oil Pipelines – comparable EBIT	**553**	457

1 Results in 2011 are for 11 months.

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $123 million higher this year than in 2011. This increase reflected higher revenues primarily resulting from:

- higher contracted volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Wood River and Patoka, in Illinois, which came into effect in May 2011
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012
- twelve months of earnings being recorded in 2012 compared to eleven months in 2011.

The Keystone Pipeline System began commercial operations in June 2010, when we began delivering crude oil to Wood River and Patoka in Illinois. We capitalized all cash flows except general, administrative and support costs until February 2011. The NEB initially restricted the operating pressure on the Canadian conversion segment of the pipeline. As a result, we could not operate it at design pressure and throughput capacity was much lower than the initial nominal capacity of 435,000 Bbl/d. The NEB removed the restriction in December 2010 and we made operational modifications in late January 2011 which allowed us to operate at higher pressure and increase throughput capacity.

We began recording EBITDA for the Keystone Pipeline System in February 2011, when we began delivering crude oil to Cushing, Oklahoma.

Business development

Business development expenses this year were $12 million higher than 2011 mainly because of increased business development activity on various development projects.

Depreciation and amortization

Depreciation and amortization was $15 million higher this year than in 2011 because 12 months of depreciation was recorded in 2012 compared to 11 months in 2011.

OUTLOOK

Earnings

We expect 2013 earnings to be consistent with 2012. Earnings are expected to increase over time as projects currently in development are placed in service.

Capital expenditures

We spent a total of $1.1 billion in 2012, and expect to spend $4.1 billion in 2013, mainly related to Keystone XL and the Gulf Coast Project. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

UNDERSTANDING THE OIL PIPELINES BUSINESS

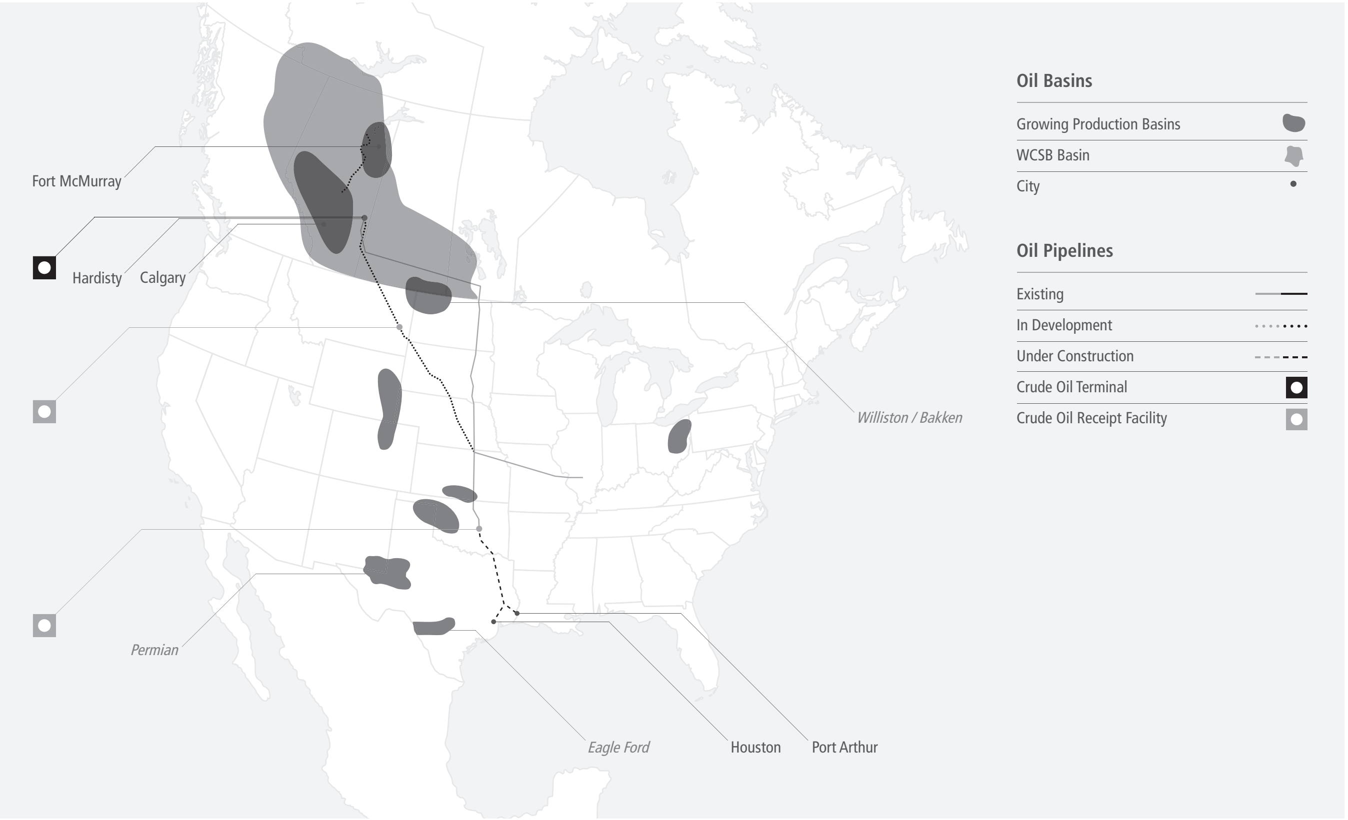
Oil pipelines move crude oil from major sources of supply to refinery markets so the crude oil can be refined into various petroleum products.

Our Keystone Pipeline System connects Alberta crude oil supplies to significant U.S. refining markets in Illinois and Oklahoma. It generates earnings mainly by providing pipeline capacity to shippers on a take-or-pay basis in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by long-term transportation service arrangements negotiated with shippers. These arrangements average 18 years, and provide for the recovery of costs we incur to operate the system.

Business environment

Increasing crude oil supply production in Canada and the U.S. has increased the demand for new crude oil pipeline infrastructure and, as a result, we are pursuing opportunities to connect growing North American crude oil supplies to key markets.



Alberta produces the majority of the crude oil in the WCSB which is the primary source of crude oil supply for the Keystone Pipeline System.

In 2011, the WCSB produced an estimated 1.1 million Bbl/d of conventional crude oil and condensate, and 1.6 million Bbl/d of Alberta oil sands crude oil – a total of approximately 2.7 million Bbl/d. The production of conventional crude oil in western Canada grew for the first time after years of decline.

In its 2012 report, the Alberta Energy Resources Conservation Board estimates there are approximately 170 billion barrels of remaining established conventional and oil sands reserves in Alberta. In June 2012, the Canadian Association of Petroleum Producers forecasted WCSB crude oil supply would increase to 3.6 million Bbl/d by 2015 and to 4.5 million Bbl/d by 2020. Its 2012 forecast for western Canadian production of conventional and unconventional crude oil in 2025 is 885,000 Bbl/d higher than its forecast in 2011.

Oil sands production

Despite increases in production from conventional sources, and new shale oil production (including the Bakken and Cardium formations), the oil sands will continue to make up most of the crude oil production from the WCSB. The Alberta Energy Resources Conservation Board's 2012 report estimates that oil sands capital expenditures increased $2.7 billion in 2011, to $19.9 billion, and predicts that investment will be $21.5 billion in 2012 and $24.7 billion in 2015.

Oil sands projects have very long lives: conservative estimates are 40 years for mining sites and 25 years for in-situ production, and some estimates are considerably higher. That means producers need to secure long-term connectivity to market. The Keystone Pipeline System, including Keystone XL, provides producers with needed pipeline capacity and is largely contracted for an average term of 18 years.

Demand for infrastructure within Alberta

Growth in oil sands production is also driving the need for new intra-Alberta pipelines, like our Grand Rapids Pipeline, that can move crude oil production from the source to market hubs at Edmonton/Heartland and Hardisty, where they can connect with the Keystone Pipeline System, and other pipelines that transport crude oil outside of Alberta, and move diluent from the Edmonton/Heartland region to the producing area in northern Alberta.

Growth in U.S. production

According to the International Energy Agency (IEA) World Energy Outlook report, the U.S. is set to overtake Saudi Arabia as the world's largest oil producer. The IEA projects approximately three million Bbl/d of U.S. shale oil production growth, peaking in approximately 2020 and starting to decline by around 2025.

The Williston Basin, located mainly in North Dakota and Montana, produced more than 600,000 Bbl/d in 2012, and production levels are expected to reach approximately one million Bbl/d by 2014 because of rapid growth in Bakken shale oil production. The Williston Basin is the primary source of crude oil supply for the Bakken Marketlink project.

According to BENTEK Energy, the Permian Basin, located mainly in western Texas, currently produces 1.3 million Bbl/d and will reach 1.8 million Bbl/d by the end of 2016. The Permian Basin is the primary source of crude oil for the Cushing Marketlink project. Growing U.S. production has contributed to increased crude oil supply at the Cushing, Oklahoma market hub and resulted in increased demand for additional pipeline capacity between Cushing and the U.S. Gulf Coast refining market. Our Gulf Coast Project will provide needed pipeline capacity to transport growing crude oil supply at Cushing to the U.S. Gulf Coast.

Even with growth in U.S. crude oil production, the IEA report predicts the U.S. will remain a net importer of crude oil, importing 3.4 million Bbl/d into 2035. Growing production in the west Texas Permian and south Texas Eagle Ford basins, which is primarily light crude oil, is expected to compete with Williston Basin light crude oil production volumes but generally will not compete with Canadian volumes. Gulf Coast refiners will continue to prefer Canadian heavy oil because their refineries are mainly set up to run heavy crude oil and cannot easily switch to running the new light shale oil in large quantities.

Refineries in eastern Canada currently import light crude oil from west Africa and the Middle East, so are better able to handle light shale oil. Many of these refineries have recently begun transporting domestic light crude oil in small quantities by rail, at a cost typically higher than the cost to ship by pipeline. This has created a significant demand for pipelines to connect eastern Canada with growing Bakken and WCSB light crude oil production. We are positioned to meet this need by potentially converting portions of our Canadian Mainline natural gas pipeline system between Alberta and eastern Canada.

SIGNIFICANT EVENTS

Tolls

We filed revised fixed tolls with the NEB and the FERC this year for committed pipeline capacity to Cushing, Oklahoma. The new tolls went into effect on July 1, 2012, and represent the final project costs of the Keystone Pipeline System.

Gulf Coast Project

We announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Pipeline has its own independent value to the marketplace, and that we plan to build it as the stand-alone Gulf Coast Project, which is not part of the Keystone XL Presidential Permit process.

The 36-inch pipeline will extend from Cushing, Oklahoma to the U.S. Gulf Coast. We expect it to have an initial capacity of up to 700,000 Bbl/d, and an ultimate capacity of 830,000 Bbl/d. We estimate the total cost of the project to be US$2.3 billion, and as of December 31, 2012, construction was approximately 35 per cent complete. US$300 million of the total cost is expected to be spent on the Houston Lateral pipeline, a 76 km (47 mile) pipeline that will transport crude oil to Houston refineries.

Construction began in August 2012 and we expect to place the pipeline in service at the end of 2013.

Keystone XL Pipeline
In May 2012, we filed a Presidential Permit application (cross-border permit) with the U.S. Department of State (DOS) for Keystone XL to transport crude oil from the U.S./Canada border in Montana to Steele City, Nebraska. We continued to work collaboratively with the Nebraska Department of Environmental Quality (NDEQ) and various other stakeholders throughout 2012 to determine an alternative route in Nebraska that would avoid the Nebraska Sandhills. We had proposed an alternative route to the NDEQ in April 2012, and then modified the route in response to comments from the NDEQ and other stakeholders.

In September 2012, we submitted a Supplemental Environmental Report to the NDEQ for the proposed re-route, and provided an environmental report to the DOS, required as part of the DOS review of our cross-border permit application.

In January 2013, the NDEQ issued its final evaluation report on our proposed re-route to the Governor of Nebraska. The report noted that the proposed re-route avoids the Nebraska Sandhills, and that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska. On January 22, 2013, the Governor of Nebraska approved our proposed re-route.

The DOS is now completing their environmental and National Interest Determination review process and we are awaiting their decision on our cross-border permit application.

The pipeline will extend from Hardisty, Alberta to Steele City, Nebraska. We estimate the total cost of the project to be US$5.3 billion and, as of December 31, 2012, had invested US$1.8 billion. We expect the pipeline to be in service in late 2014 or early 2015, subject to regulatory approvals.

Marketlink Projects
We have commenced construction on the Cushing Marketlink receipt facilities and expect to begin transporting crude oil supply from the Permian Basin producing region in western Texas to the U.S. Gulf Coast in late 2013 after our Gulf Coast Project is placed in service. Our Bakken Marketlink project will transport crude oil supply from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL which remains subject to regulatory approval.

Keystone Hardisty Terminal
We announced in May 2012 that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.

The terminal will provide new crude oil batch accumulation tankage and pipeline infrastructure for western Canadian producers, and access to the Keystone Pipeline System.

We expect the terminal to be operational in late 2014 and cost approximately $275 million.

Northern Courier Pipeline
We announced in August 2012 that we had been selected by Fort Hills Energy Limited Partnership to design, build, own and operate the proposed Northern Courier Pipeline.

The 90 km (54 mile) pipeline system will transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader, north of Fort McMurray, Alberta. We estimate total capital costs to be $660 million. The pipeline is fully subscribed under long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc, Total E&P Canada Ltd. and Teck Resources Limited.

The project is conditional on the Fort Hills project receiving sanctions by the owners of the Fort Hills mine and is subject to regulatory approval.

Grand Rapids Pipeline

We announced in October 2012 that we had entered into binding agreements with Phoenix to develop the Grand Rapids Pipeline in northern Alberta.

The project includes crude oil and diluent lines to transport volumes approximately 500 km (300 miles), between the producing area northwest of Fort McMurray and the Edmonton/Heartland region. It will have the capacity to move up to 900,000 Bbl/d of crude oil and 330,000 Bbl/d of diluent.

We and Phoenix will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Phoenix has entered into a long-term commitment to ship crude oil and diluent.

The Grand Rapids Pipeline system, subject to regulatory approvals, is expected to be placed in service in multiple stages, with initial crude oil service by mid-2015 and the complete system in service by the second half of 2017.

Canadian Mainline conversion

We have determined that it is technically and economically feasible to convert a portion of the Canadian Mainline natural gas pipeline system to crude oil service. The proposed pipeline will deliver crude oil between Hardisty, Alberta and markets in eastern Canada through a combination of converted natural gas pipelines and new construction. We are actively pursuing this project and have begun soliciting input from stakeholders and prospective shippers to determine market acceptance.

BUSINESS RISKS

The following are risks specific to our oil pipelines business. See page 70 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Operational

Optimizing and maintaining availability of our oil pipeline is essential to the success of our oil pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced capacity payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our oil pipelines. Public opinion about crude oil development and production also has an impact on the regulatory process. There are some individuals and interest groups that are expressing their opposition to crude oil production by opposing the construction of oil pipelines. We manage this risk by continuously monitoring regulatory developments and decisions to determine their possible impact on our oil pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

Investing in large infrastructure projects involves substantial capital commitments, based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays and potentially reduced investment returns.

Crude oil supply and demand for pipeline capacity

Demand for crude oil pipeline capacity is dependent on the level of crude oil supply and demand for refined crude oil products. New producing technologies such as steam assisted gravity drainage and horizontal drilling in combination with fracking are allowing producers to economically increase development of unconventional resources, such as oil sands and shale oil at current crude oil prices, and have resulted in increased demand for new crude oil pipeline infrastructure. A decrease in demand for refined crude oil products could adversely impact the price of oil producers receive for their product. Lower margins for crude oil could mean producers curtail their investment in the development of crude oil supplies. Depending on their severity, these factors would negatively impact the opportunities we have to expand our crude oil pipeline infrastructure and, in the longer term, contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American crude oil transportation market to transport growing WCSB, Williston Basin and Permian Basin crude oil supplies to key U.S. refining markets, we face competition from other pipeline companies and to a lesser extent, rail companies which also seek to transport these crude oil supplies to market. Our success is dependant on our ability to offer and contract transportation services on terms that are market competitive.

Energy

TCPL's Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing more than 11,800 MW of generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our U.S. power business is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are critically located, essential capacity.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

We own or control approximately 156 Bcf of unregulated natural gas storage capacity in Alberta, accounting for approximately one-third of all storage capacity in the province. When combined with the regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment), we provide approximately 407 Bcf of natural gas storage and related services.

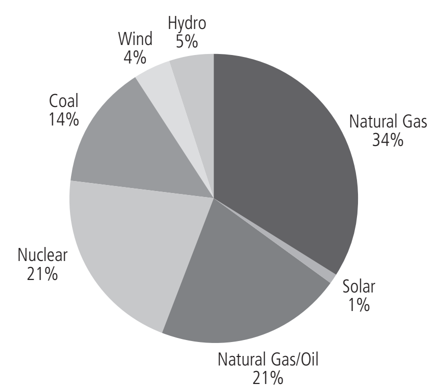
Strategy at a glance

We are focusing on low-cost, long-life electrical infrastructure and natural gas storage assets supported by strong market fundamentals, and the opportunity for long-term contracts with reputable and creditworthy counterparties. Our investment in natural gas, nuclear, wind, hydro-power and solar generating facilities demonstrates our commitment to clean, sustainable energy.

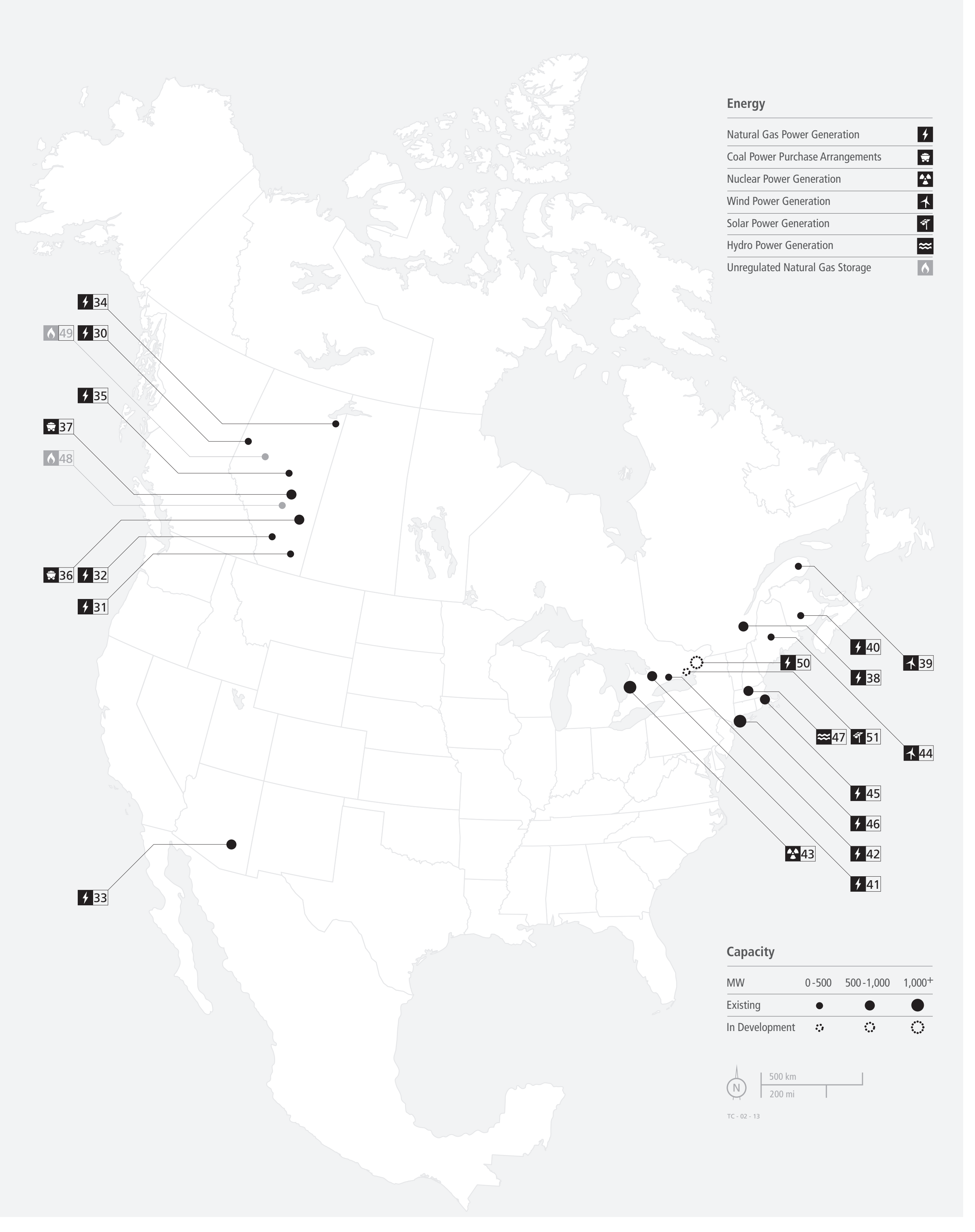
The growth in demand for power in North America is expected to provide the opportunity to participate in new generation and other power infrastructure projects. Current low natural gas prices make natural gas generation a very cost-competitive option to meet the growing demand in the markets we serve.

Natural gas storage will continue to serve market needs and will play an important role in balancing supply and demand as additional gas supplies are connected to North American and world markets.

Power by Fuel Source[1]



1 Includes facilities under development.



Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
34
49
30
35
37
48
36
32
31
33
40
39
50
38
47
51
44
45
46
42
43
41
Capacity
MW 0-500 500-1,000 1,000+
Existing
In Development
500 km
200 mi
TC - 02 - 13

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce A and B and Portlands Energy.

		generating capacity (MW)	type of fuel	description	location	ownership
	Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
	Western Power 2,636 MW of power supply in Alberta and the western U.S.					
30	Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
31	Cancarb	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TCPL facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
32	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
33	Coolidge[1]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
34	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
35	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
36	Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
37	Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
37	Sundance B PPA (Owned by ASTC Power Partnership[2])	353[3]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
	Eastern Power 2,950 MW of power generation capacity (including facilities in development)					
38	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
39	Cartier Wind	366[3]	wind	Five wind power projects	Gaspésie, Québec	62%
40	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
41	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
42	Portlands Energy	275[3]	natural gas	Combined-cycle plant	Toronto, Ontario	50%

		generating capacity (MW)	type of fuel	description	location	ownership
	Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
43	Bruce A	1,462[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
43	Bruce B	1,022[3]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
	U.S. Power 3,755 MW of power generation capacity					
44	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
45	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
46	Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
47	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
48	CrossAlta	68 Bcf[4]		Underground facility connected to Alberta System	Crossfield, Alberta	100%
49	Edson	50 Bcf		Underground facility connected to Alberta System	Edson, Alberta	100%
	In development					
50	Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
51	Ontario Solar	86	solar	Nine solar projects from Canadian Solar Solutions Inc. We expect to acquire the first two projects in the first half of 2013, and the remaining seven projects in 2013 to late 2014	Southern Ontario and New Liskeard, Ontario	100%

1 Located in Arizona, results reported in Canadian Power – Western Power.

2 We have a 50 per cent interest in ASTC Power Partnership, which has a PPA in place for 100 per cent of the production from the Sundance B power generating facilities.

3 Our share of power generation capacity.

4 Reflects the acquisition of an additional 27 Bcf of working gas storage capacity in December 2012.

RESULTS

Comparable EBITDA, and comparable EBIT are non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	2012	2011	2010
Canadian Power			
Western Power[1]	**335**	483	212
Eastern Power[2]	**345**	297	212
Bruce Power	**14**	110	173
General, administrative and support costs	**(48)**	(43)	(38)
Canadian Power – comparable EBITDA[3]	**646**	847	559
Depreciation and amortization[4]	**(152)**	(141)	(114)
Canadian Power – comparable EBIT[3]	**494**	706	445
U.S. Power (US$)			
Northeast Power[5]	**257**	314	335
General, administrative and support costs	**(48)**	(41)	(32)
U.S. Power – comparable EBITDA	**209**	273	303
Depreciation and amortization	**(121)**	(109)	(116)
U.S. Power – comparable EBIT	**88**	164	187
Foreign exchange	**-**	(4)	7
U.S. Power – comparable EBIT (Cdn$)	**88**	160	194
Natural Gas Storage			
Alberta Storage	**77**	84	136
General, administrative and support costs	**(10)**	(6)	(8)
Natural Gas Storage – comparable EBITDA[3]	**67**	78	128
Depreciation and amortization[4]	**(10)**	(12)	(13)
Natural Gas Storage – comparable EBIT[3]	**57**	66	115
Business development comparable EBITDA and EBIT	**(19)**	(25)	(32)
Energy – comparable EBIT[3]	**620**	907	722
Summary			
Energy – comparable EBITDA[3]	**903**	1,168	969
Depreciation and amortization[4]	**(283)**	(261)	(247)
Energy – comparable EBIT[3]	**620**	907	722

1 Includes Coolidge starting in May 2011.
2 Includes Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011 and Montagne-Sèche starting in November 2011; Halton Hills starting in September 2010.
3 Includes our share of equity income from our equity accounted for investments in ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta up to December 18, 2012. On December 18, 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent.
4 Does not include depreciation and amortization of equity investments.
5 Includes phase two of Kibby Wind starting in October 2010.

Comparable EBITDA for Energy was $903 million in 2012, or $265 million lower than 2011. This reflected the net effect of:

- decreased Western Power earnings due to the Sundance A PPA force majeure
- incremental earnings from Cartier Wind in Eastern Power and Coolidge in Western Power
- lower equity income from Bruce Power due to increased planned outage days
- decreased U.S. Power earnings because of lower realized power prices, higher load serving costs and reduced water flows at the TC Hydro facilities.

OUTLOOK

Earnings

We expect 2013 earnings from the Energy segment to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and fewer planned outage days at Bruce A
- a full year of operations from Gros-Morne which was placed in service in fourth quarter 2012
- higher New York capacity prices as a result of the September 2012 FERC order affecting pricing rules for new entrants
- the acquisition of several of the Ontario Solar assets beginning in early 2013
- we acquired the remaining 40 per cent interests in CrossAlta in December 2012
- the return to service of Sundance A in fall 2013
- offset by higher outage days at Bruce B and higher pension and staff costs at Bruce A and B.

Although a significant portion of Energy's output is sold under long-term contracts, power that is sold under shorter-term forward arrangements or at spot prices will continue to be affected by fluctuations in commodity prices. Fluctuations in Alberta, New England and New York power prices will affect Energy's earnings in 2013, and winter/summer natural gas price spreads will affect earnings in Gas Storage. Timing of the return of the Sundance A units may also have an impact on Western Power's earnings in late 2013.

Weather, unplanned outages, regulatory changes and the overall stability of the energy industry may also affect earnings in 2013.

Western Power

Alberta power market fundamentals are strong and new power capacity and transmission projects are being developed to meet the significant growth in demand. Consumption has been growing since 2009, mirroring economic growth since the recession. The outlook for forward oil prices supports ongoing investment in the oil sands and the associated development is expected to underpin continuing economic growth and increased power demand. Average Alberta power demand in 2012 was almost three per cent higher than 2011. The Alberta Electric System Operator is forecasting that demand will continue to grow at a similar rate over the next 10 years, and estimates that about 6,000 MW of new generation will be required. We expect to participate in new generation additions and other power infrastructure projects to meet Alberta's growing demand. Despite this rising demand, average power prices in Alberta in 2012 ($64/MWh) were lower than 2011 ($77/MWh). Spot market power prices are a function of many factors, including supply/demand conditions and natural gas prices. The supply of power is for the most part dictated by the performance of the coal fleet and wind availability, while power demand is highly influenced by the weather and seasonal factors. Natural gas prices, which at times were below $2/GJ, contributed to the low power prices, especially in offpeak and windy onpeak periods. The return of the Sundance A units in late 2013, the addition of a power transmission line to Montana in 2013 and a large combined cycle plant under construction for 2015 could have a negative effect on Alberta power prices in the near and medium term.

Eastern Power

Our existing energy assets in Ontario are largely insulated from changes in the market price of power through contracts with the Ontario Power Authority (OPA). The Ontario Independent Electricity System Operator forecasts growth in the demand for power will be flat in 2013 as conservation programs and time of use pricing temper demand. Ontario's remaining coal power stations will be retired by the end of 2013. Within the next decade, Ontario's aging nuclear units will require significant investments to extend their lives or will otherwise face retirement, which may provide development opportunities for us in the future.

U.S. Power

In New England, average power demand fell one per cent this year partly due to warm winter weather and there was a net increase of 240 MW of power supply (approximately 400 MW of new power supply was added and 160 MW retired). These supply/demand conditions, combined with low natural gas prices, resulted in a reduction in the average New England ISO power price to US$36/MWh in 2012 from US$47/MWh in

2011. The New England ISO forecasts growth in the demand for power of about one per cent per year in the coming years, based on modest economic growth.

Average power demand in New York fell one per cent in 2012 because of the economic situation, warm winter weather and the loss of demand associated with Superstorm Sandy. There was also a net reduction of 100 MW in power supply (approximately 500 MW of new power supply was added and 600 MW was retired). This supply/demand environment, combined with low natural gas prices, reduced the average New York ISO power price for New York City to US$39/MWh in 2012, from about US$51/MWh in 2011. The New York ISO forecasts power demand will grow one per cent per year over the next decade, based on modest growth in the population and the economy.

Capital expenditures

We spent a total of $24 million in 2012, and expect to spend $130 million on capital expenditures in Energy in 2013. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

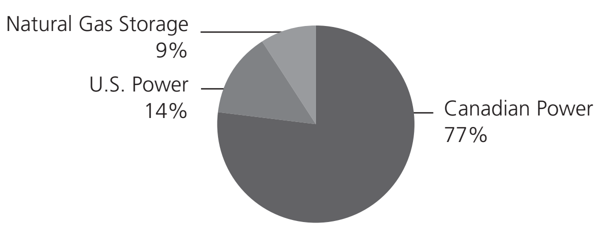
Equity investments and acquisitions

In 2012, we also invested $0.7 billion in Bruce Power for capital projects which included the restart of Units 1 and 2 and the West Shift Plus life extension outage on Unit 3 as well as $0.2 billion for the acquisition of the remaining 40 per cent interest in CrossAlta. We expect to spend approximately $0.3 billion on the acquisition of Ontario solar assets and Bruce Power investments in 2013.

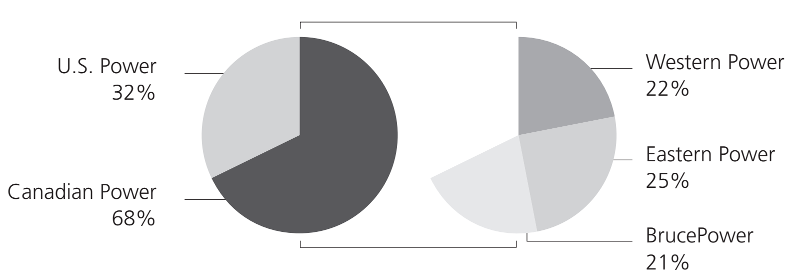
UNDERSTANDING THE ENERGY BUSINESS

Our Energy business is made up of three groups:
- Canadian Power
- U.S. Power
- Natural Gas Storage

Energy comparable EBIT – contribution by group, excluding business development expenses
Year ended December 31, 2012



Power generation capacity – contribution by group
Year ended December 31, 2012



Canadian Power

Western Power

We own or have the rights to approximately 2,600 MW of power supply in Alberta and Arizona, through three long-term PPAs, five natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50% through the ASTC Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

Earnings in the Western Power business are maximized by maintaining and optimizing the operations of our power plants, and through various marketing activities.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability, and is not a function of market price.

The marketing function is critical for optimizing returns and managing risk through direct sales to medium and large industrial and commercial companies and other market participants. Our marketing group sells power sourced through the PPAs, markets uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available.

A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

Eastern Power

We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under contract. Disciplined maintenance of plant operations is critical to the results of our eastern power assets, where earnings are based on plant availability and performance.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1]	20-year PPA Steam sold to an industrial customer.	Hydro-Québec	2026
Cartier Wind	20-year PPA	Hydro-Québec	2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2025
Halton Hills	20-year Clean Energy Supply contract	OPA	2030
Portlands Energy	20-year Clean Energy Supply contract	OPA	2029

1 Power generation has been suspended since 2008.

Assets currently in development are as follows:

	Type of contract	With	Expires
Ontario Solar	20-year Feed-in Tariff (FIT) contracts	OPA	20 years from in-service date
Napanee	20-year Clean Energy Supply contract	OPA	20 years from in-service date

Western and Eastern Power results[1,2]

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Revenue			
Western power[1]	**640**	822	598
Eastern power[2]	**415**	391	243
Other[3]	**91**	69	83
	1,146	1,282	924
Income from equity investments[4]	**68**	117	74
Commodity purchases resold			
Western power	**(281)**	(368)	(363)
Other[5]	**(5)**	(9)	(26)
	(286)	(377)	(389)
Plant operating costs and other	**(218)**	(242)	(185)
Sundance A PPA arbitration decision[6]	**(30)**	-	-
General, administrative and support costs	**(48)**	(43)	(38)
Comparable EBITDA	**632**	737	386
Depreciation and amortization[7]	**(152)**	(141)	(114)
Comparable EBIT	**480**	596	272

1 Includes Coolidge starting in May 2011.
2 Includes Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011, and Montagne-Sèche starting in November 2011; Halton Hills starting in September 2010.
3 Includes sale of excess natural gas purchased for generation and sales of thermal carbon black.
4 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
5 Includes the cost of excess natural gas not used in operations.
6 See *Significant events* for more information about the Sundance A PPA arbitration decision.
7 Does not include depreciation and amortization of equity investments.

Sales volumes and plant availability[1,2]

Includes our share of volumes from our equity investments.

year ended December 31	2012	2011	2010
Sales volumes (GWh)			
Supply			
Generation			
Western Power[1]	**2,691**	2,606	2,373
Eastern Power[2]	**4,384**	3,714	2,359
Purchased			
Sundance A & B and Sheerness PPAs[3]	**6,906**	7,909	10,785
Other purchases	**46**	248	314
	14,027	14,477	15,831
Sales			
Contracted			
Western Power[1]	**8,240**	8,381	10,096
Eastern Power[2]	**4,384**	3,714	2,375
Spot			
Western Power	**1,403**	2,382	3,360
	14,027	14,477	15,831
Plant availability[4]			
Western Power[1,5]	**96%**	97%	95%
Eastern Power[2,6]	**90%**	93%	94%

1 Includes Coolidge starting in May 2011.

2 Includes Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011, and Montagne-Sèche starting in November 2011; Halton Hills starting in September 2010. Also includes volumes related to our 50 per cent ownership interest in Portlands Energy.

3 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. No volumes were delivered under the Sundance A PPA in 2012 or 2011.

4 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.

5 Does not include facilities that provide power to TCPL under PPAs.

6 Does not include Bécancour because power generation has been suspended since 2008.

Western Power's comparable EBITDA was $335 million in 2012, or $148 million lower than 2011. This was primarily due to the net effect of:

- the Sundance A PPA force majeure
- lower purchased PPA volumes during periods of lower spot prices
- lower equity earnings from ASTC Power Partnership because of the Sundance B arbitration decision
- incremental earnings from Coolidge, which was placed in service in May 2011
- higher realized power prices and
- lower fuel costs.

In the first quarter of 2012, we recorded revenues and costs related to the Sundance A PPA as though the outages of Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA. In July 2012, we received the Sundance A PPA arbitration decision, and recorded a charge of $30 million; an amount equivalent to the pre-tax income we had recorded in first quarter. Because the plant is now in force majeure, we will not record further revenues and costs until the units are returned to service. See pages 57 and 58 for more information about the Sundance A and Sundance B PPA arbitration decisions.

In 2011, Western Power's comparable EBITDA was $483 million, or $271 million higher than 2010, and revenue was $822 million, or $224 million higher than 2010. These increases were mainly the result of higher overall realized power prices in Alberta, and incremental earnings from Coolidge, which went in service in May 2011.

Purchased volumes in 2012 were lower than 2011 mainly because of lower utilization of the Sundance B and Sheerness PPAs during periods of lower spot market power prices, and higher plant outage days. Average spot market power prices in Alberta were $64 per MWh in 2012, or 16 per cent lower than 2011. Despite the decrease in spot prices, Western Power earned a higher realized price per MWh in 2012 compared to 2011 as a result of contracting activities.

Western Power's revenue was $640 million in 2012, or $182 million lower than 2011. This was the net effect of:

- the Sundance A PPA force majeure
- lower purchased PPA volumes during periods of lower spot prices
- incremental earnings from Coolidge which was placed in service in May 2011 and
- higher realized power prices resulting from contracting activities.

Western Power's commodity purchases resold were $281 million in 2012, or $87 million lower than 2011 because of the Sundance A PPA force majeure and lower purchased volumes.

Eastern Power's comparable EBITDA was $345 million in 2012, or $48 million higher than 2011. Revenue also increased by $24 million in 2012, to $415 million. The increases were mainly due to:

- incremental earnings from Cartier (Montangne-Sèche and phase one of Gros-Morne, which were placed in service in November 2011, and phase two of Gros-Morne which was placed in service in November 2012), and
- higher contractual earnings at Bécancour.

In 2011, Eastern Power's comparable EBITDA was $297 million, or $85 million higher than 2010. Revenue also increased by $148 million in 2011, to $391 million. The increases were mainly because Halton Hills was placed in service in September 2010, giving us incremental earnings in 2011.

Income from equity investments was $68 million in 2012, or $49 million lower than 2011, mainly due to lower earnings from ASTC Power Partnership because of:

- lower Sundance B PPA volumes
- lower spot market power prices and
- the impact of the Sundance B PPA arbitration decision.

In 2011, income from equity investments was $117 million, or $43 million higher than 2010, mainly because higher spot market power prices increased earnings from the ASTC Power Partnership.

Plant operating costs and other, which includes natural gas fuel consumed in power generation, were $218 million in 2012, or $24 million lower than 2011, mainly because natural gas fuel prices were lower in 2012. In 2011, they were $242 million, or $57 million higher than 2010 mainly because of incremental fuel consumed at Halton Hills.

Depreciation and amortization was $152 million in 2012, or $11 million higher than 2011, mainly because of incremental depreciation from Cartier and Coolidge. In 2011, depreciation and amortization was $141 million, or $27 million higher than 2010 mainly because of incremental depreciation from Halton Hills and Coolidge being placed in service.

Approximately 85 per cent of Western Power sales volumes were sold under contract in 2012 compared to 78 per cent in 2011 and 75 per cent in 2010. To reduce its exposure to spot market prices in Alberta, Western Power has entered into fixed-price power sales contracts to sell approximately 6,700 GWh for 2013 and approximately 4,300 GWh for 2014.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and comprises Bruce A and Bruce B. Bruce A Units 1 to 4 have a combined capacity of approximately 3,000 MW and Bruce B Units 5 to 8 have a combined capacity of approximately 3,200 MW. Bruce B leases the eight nuclear reactors from Ontario Power Generation and subleases Units 1 to 4 to Bruce A.

Bruce Power's generating capacity is fully contracted with the OPA. Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

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

Bruce A fixed price	Per MWh
April 1, 2012 – March 31, 2013	$68.23
April 1, 2011 – March 31, 2012	$66.33
April 1, 2010 – March 31, 2011	$64.71

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

Bruce B floor price	Per MWh
April 1, 2012 – March 31, 2013	$51.62
April 1, 2011 – March 31, 2012	$50.18
April 1, 2010 – March 31, 2011	$48.96

Bruce B is required to repay payments it receives under the floor price mechanism within a calendar year when the monthly average spot price exceeds the floor price. It has not had to repay any amounts recorded in revenues in the past three years.

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

Bruce Power results

Our proportionate share

year ended December 31 (millions of $, unless otherwise indicated)	2012	2011	2010
Income/(loss) from equity investments[1]			
Bruce A	**(149)**	33	35
Bruce B	**163**	77	138
	14	110	173
Comprised of:			
Revenues	**763**	817	862
Operating expenses	**(567)**	(565)	(564)
Depreciation and other	**(182)**	(142)	(125)
	14	110	173
Bruce Power – other information			
Plant availability[2]			
Bruce A[3]	**54%**	90%	81%
Bruce B	**95%**	88%	91%
Combined Bruce Power	**81%**	89%	88%
Planned outage days			
Bruce A	**336**	60	60
Bruce B	**46**	135	70
Unplanned outage days			
Bruce A	**18**	16	64
Bruce B	**25**	24	34
Sales volumes (GWh)[1]			
Bruce A[3]	**4,194**	5,475	5,026
Bruce B	**8,475**	7,859	8,184
	12,669	13,334	13,210
Realized sales price per MWh			
Bruce A	**$68**	$66	$65
Bruce B[4]	**$55**	$54	$58
Combined Bruce Power	**$57**	$57	$60

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
2 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.
3 Plant availability and sales volumes for 2012 include the incremental impact of Unit 1 which was returned to service on October 22 and Unit 2, which was returned to service on October 31.
4 Includes revenues under the floor price mechanism, revenues from contract settlements and volumes and revenues associated with deemed generation.

Equity income from Bruce A decreased by $182 million in 2012, to a loss of $149 million, compared to income of $33 million in 2011. The decrease was mainly due to:

- lower volumes and higher operating costs resulting from the ongoing Unit 4 planned outage, which began on August 2, 2012 and
- the Unit 3 West Shift Plus planned outage, which began in November 2011 and was completed in June 2012.

These were partially offset by incremental earnings from Units 1 and 2, which were returned to service on October 22 and October 31, 2012, respectively.

Units 1 and 2 have operated at reduced output levels following their return to service and, in late November 2012, Bruce Power took Unit 1 offline for an approximate one month maintenance outage. Bruce Power expects the availability percentages for Units 1 and 2 to increase over time; however, these units have not operated for an extended period of time and may experience slightly higher forced outage rates and reduced availability percentages in 2013. Overall plant availability for Bruce A is expected to be approximately 90 per cent in 2013.

Equity income from Bruce B was $163 million in 2012, or $86 million higher than 2011. The increase was mainly due to higher volumes and lower operating costs resulting from fewer planned outage days, lower lease expense and higher realized prices.

In 2011, equity income from Bruce Power was $110 million, or $63 million lower than 2010. The decrease was mainly from lower equity income at Bruce B, due to lower realized prices resulting from expiration of fixed-price contracts at higher prices and higher operating costs and lower volumes due to increased outage days. Equity income from Bruce Power in 2010 also included the net positive impact of a payment Bruce B made to Bruce A in 2010, related to amendments made to the agreements with the OPA in 2009. The net impact was positive because we have a higher percentage ownership in Bruce A.

The overall plant availability percentage in 2013 is expected to be approximately 90 per cent for Bruce A and high 80s for Bruce B. The Unit 4 outage, which began on August 2, 2012, is expected to be completed in late first quarter 2013. Planned maintenance on Bruce B units is scheduled to occur during the first half of 2013.

U.S. Power

We own approximately 3,800 MW of power generation capacity in New York and New England, including plants powered by natural gas, oil, hydro and wind.

We earn revenues in both New York and New England in two ways – by providing capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. The energy markets compensate power providers for the actual energy they supply.

Providing capacity

Capacity revenues in New York and New England are a function of two factors – capacity prices and plant availability. It is important for us to keep our plant availability high to maximize the amount of capacity we get paid for.

Capacity prices paid to capacity suppliers in New York are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. The parameters are determined for each zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in the forecasted demand. Since 2011, we have been engaged in an ongoing regulatory process related to a number of capacity pricing issues in the New York Zone J market where our Ravenswood facility operates. See page 59 for more information.

The price paid for capacity in the New England Power Pool is determined by annual competitive auctions which are held three years in advance of the applicable capacity year. Auction results are impacted by actual and projected power demand, power supply, and other factors.

Selling energy

We focus on selling power under short- and long-term contracts to wholesale, commercial and industrial customers. In some cases, power sales are bundled with other energy services that we earn additional revenues for providing in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM), a regional transmission organization that coordinates the movement in wholesale electricity in all or parts of 13 states and the District of Columbia.

We meet our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices.

U.S. Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 12 for more information for more details.

year ended December 31 (millions of US$)	**2012**	**2011**	**2010**
Revenue			
Power[1,2]	**1,189**	1,139	1,319
Capacity	**234**	227	231
Other[3]	**51**	80	78
	1,474	1,446	1,628
Commodity purchases resold	**(765)**	(618)	(772)
Plant operating costs and other[2]	**(452)**	(514)	(521)
General, administrative and support costs	**(48)**	(41)	(32)
Comparable EBITDA[1]	**209**	273	303
Depreciation and amortization[1]	**(121)**	(109)	(116)
Comparable EBIT[1]	**88**	164	187

1 Includes phase two of Kibby Wind starting in October 2010.
2 The realized 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.
3 Includes revenues and costs related to a third party service agreement at Ravenswood, the activity level of which decreased in 2012.

Sales volumes and plant availability

year ended December 31	**2012**	**2011**	**2010**
Physical sales volumes (GWh)			
Supply			
Generation	**7,567**	6,880	6,755
Purchased	**9,408**	6,018	8,899
	16,975	12,898	15,654
Plant availability[1]	**85%**	87%	86%

1 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

U.S. Power's comparable EBITDA was US$209 million in 2012, or US$64 million lower than 2011. This reflected the net effect of:

- lower realized power prices
- higher load serving costs
- reduced water flows at the TC Hydro facilities
- increased generation at the Ravenswood facility and
- higher sales to wholesale, commercial and industrial customers.

In 2011, comparable EBITDA was US$273 million, or US$30 million lower than 2010. This was mainly the result of the negative impact of lower commodity and capacity prices and lower physical sales volumes, partially offset by new sales activity in PJM, an increase in the New York commercial customer base and incremental earnings from phase two of Kibby Wind, which was placed in service in October 2010.

Physical sales volumes in 2012 have increased compared to the same period in 2011, partly due to higher purchased volumes to serve increased sales to wholesale, commercial and industrial customers in the PJM and New England markets. Generation volumes were also higher, mainly because of higher volumes at Ravenswood in the last quarter of 2012 resulting from Superstorm Sandy. Ravenswood ran at higher than normal generation levels both during and following the storm when damage at several other power and transmission facilities reduced power supply in the area. This increase in generation volumes was partly offset by lower hydro volumes.

Power revenue was US$1,189 million in 2012, or US$50 million higher than 2011. This was mainly due to higher sales volumes, partly offset by the effect of lower realized power prices on revenues.

Capacity revenue was US$234 million in 2012, or US$7 million higher than 2011 because realized capacity prices in New York were higher, partially offset by lower capacity prices in New England.

Commodity purchases resold were US$765 million in 2012, or US$147 million higher than 2011 because volumes of physical power purchased for resale under power sales commitments to wholesale, commercial and industrial customers were higher, and load serving costs were higher. The impact of higher volumes was partially offset by lower realized prices on purchased power.

In 2011, power revenue was $1,139 million, or $180 million lower than 2010, and commodity purchases resold were $618 million, or $154 million lower than 2010, mainly because volumes of physical power purchased for resale under power sales commitments to wholesale, commercial and industrial customers were lower.

Plant operating costs and other, which includes fuel gas consumed in generation, was US$452 million in 2012, or US$62 million lower than 2011 mainly because natural gas fuel prices were lower, partly offset by higher gas consumption at Ravenswood resulting from increased generation.

As at December 31, 2012, approximately 2,600 GWh or 34 per cent of US Power's planned generation is contracted for 2013, and 1,000 GWh or 13 per cent for 2014. 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

We own or control 156 Bcf of non-regulated natural gas storage capacity in Alberta. This includes contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015. This business operates independently from our regulated natural gas transmission business and from ANR's regulated storage business, which are included in our Natural Gas Pipelines segment.

Storage capacity

year ended December 31	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta[1]	68	550
Third-party storage	38	630
	156	1,905

1 Reflects the acquisition of the 40 per cent interest held by BP resulting in an additional 27 Bcf of working gas storage capacity in December 2012.

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements.

The natural gas storage business is affected by the change in seasonal natural gas price spreads, which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. We manage this exposure by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. We sell a portfolio of short, medium and long-term storage products to participants in the Alberta and interconnected gas markets.

Proprietary natural gas storage transactions include a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to seasonal natural gas price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value through net income based on the forward market prices for the contracted month of delivery. We record changes in the fair value of these contracts in revenues. We do not include changes in the fair value of natural gas forward purchase and sales contracts when we calculate comparable earnings, because they do not represent the amounts that will be realized on settlement.

Natural Gas Storage results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Alberta Storage[1]	**77**	84	136
General, administrative and support costs	**(10)**	(6)	(8)
Natural Gas Storage – comparable EBITDA	**67**	78	128
Depreciation and amortization	**(10)**	(12)	(13)
Natural Gas Storage – comparable EBIT	**57**	66	115

1 Includes our share of equity income from our investment in CrossAlta up to December 18, 2012. On December 18, 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent. See significant events on page 59.

Comparable EBITDA was $67 million in 2012, or $11 million lower than 2011, mainly due to the impact of lower realized natural gas storage price spreads, partially offset by lower operating costs throughout the year.

In 2011, comparable EBITDA was $78 million, or $50 million lower than 2010, mainly due to lower realized natural gas storage price spreads.

SIGNIFICANT EVENTS

Canadian Power

Western Power

Sundance A PPA

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and, in January 2011, were subject to a force majeure claim by TransAlta. In February 2011, TransAlta informed us that it was not economic to replace or repair Units 1 and 2, and that the Sundance A PPA should be terminated.

We disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA. In July 2012, an arbitration panel decided that the PPA should not be terminated and ordered TransAlta to rebuild Units 1 and 2. The panel also limited TransAlta's force majeure claim, from November 20, 2011 until the units can reasonably be returned to service. TransAlta announced that it expects the units to be returned to service in the fall of 2013.

Since we considered the outages to be an interruption of supply, we accrued $188 million in pre-tax income between December 2010 and March 2012. The outcome of the decision was that we received approximately $138 million of this amount. We recorded the $50 million difference as a charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011.

We will not record further revenue or costs from the PPA until the units are returned to service. The net book value of the Sundance A PPA recorded in Intangibles and Other Assets remains fully recoverable.

Sundance B PPA

In second quarter 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components and was subject to a force majeure claim by TransAlta. The ASTC Power Partnership, which holds the Sundance B PPA, disputed the claim under the binding dispute resolution process provided in the PPA because we did not believe TransAlta's claim met the test of force majeure. We therefore recorded equity earnings from our 50 per cent ownership interest in ASTC Power Partnership as though this event were a normal plant outage.

In November 2012, an arbitration decision was reached with the arbitration panel granting partial force majeure relief to TransAlta, and we reduced our equity earnings by $11 million from the ASTC Power Partnership to reflect the amount that will not be recovered as result of the decision.

Eastern Power

Napanee Generating Station

In December 2012, we signed a contract with the OPA, to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in Eastern Ontario in the town of Greater Napanee. The plant will replace the facility that was planned and subsequently cancelled in the community of Oakville and will operate under a 20-year Clean Energy Supply contract with the OPA. We were reimbursed for $250 million of costs, mainly related to natural gas turbines that were purchased for the Oakville project, which will now be used at Napanee. We plan to invest approximately $1.0 billion in the Napanee facility.

Cartier Wind

We placed the second phase of the Gros-Morne wind farm project (111 MW) in service in November 2012, completing the 590 MW, five-phase Cartier Wind Project in Québec. All of the power produced by Cartier Wind is sold to Hydro-Québec under 20-year PPAs.

Ontario Solar

In late 2011, we agreed to buy nine Ontario solar projects (combined capacity of 86 MW) from Canadian Solar Solutions Inc., for approximately $476 million. Under the terms of the agreement, Canadian Solar Solutions Inc. will develop and build each of the nine solar projects using photovoltaic panels. We will buy each project once construction and acceptance testing are complete and commercial operation begins. All power produced will be sold under 20-year PPAs with the OPA under the FIT program in Ontario.

We expect to close the acquisition of the first two projects (combined capacity of 20 MW) in the first half of 2013 for a total cost of approximately $125 million. We expect to acquire the other seven projects in 2013 to late 2014, subject to regulatory approvals.

Bécancour

In June 2012, Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013. Under the suspension agreement, Hydro-Québec has the option (subject to certain conditions) to extend the suspension every year until regional electricity demand levels recover. We continue to receive capacity payments while generation is suspended.

Bruce Power

This year, Bruce Power completed the refurbishment of Units 1 and 2. Unit 1 was returned to service on October 22, 2012, and Unit 2 on October 31, 2012. An incident in May 2012 within the Unit 2 electrical generator on the non-nuclear side of the plant had delayed returning the units to service. Bruce Power's force majeure claim to the OPA was accepted in August, and it continued to receive the contracted price for power generated during the force majeure period.

Units 1 and 2 have operated at reduced output levels following their return to service and, in late November 2012, Bruce Power took Unit 1 offline for an approximate one month maintenance outage. Bruce Power expects the availability percentages for Units 1 and 2 to increase over time; however, these units have not operated for an extended period of time and may experience slightly higher forced outage rates and reduced availability percentages in 2013. Overall plant availability for Bruce A is expected to be approximately 90 per cent in 2013.

Bruce Power also continued its strategy to maximize the operating life of its reactors. It returned Unit 3 to service in June after completing the $300 million West Shift Plus life extension outage, which began in 2011. Unit 4 is expected to return to service in late first quarter 2013 after the completion of an expanded outage investment program that began in August 2012. These investments should allow Units 3 and 4 to produce low cost electricity until at least 2021.

U.S. Power

Ravenswood

In 2011, we jointly filed two formal complaints with the FERC challenging how the New York ISO applied its buy-side mitigation rules affecting bidding criteria associated with two new power plants that began service in the New York Zone J markets during the summer of 2011.

In June 2012, the FERC addressed the first complaint, indicating it would take steps to increase transparency and accountability for future mitigation exemption tests (MET) and decisions. In September, 2012, the FERC granted an order on the second complaint, directing the New York ISO to retest the two new power plants as well as a transmission project currently under construction using an amended set of assumptions to more accurately perform the MET calculations, in accordance with existing rules and tariff provisions. The recalculation was completed in November 2012 and it was determined that one of the plants had been granted an exemption in error. That exemption was revoked and the plant is now required to offer its capacity at a floor price which has put upward pressure on capacity auction prices since December. The order was prospective only and has no impact on capacity prices for prior periods.

Natural Gas Storage

CrossAlta

In December 2012, we acquired the remaining 40 per cent interests in the Crossfield Gas Storage facility and CrossAlta Gas Storage & Services Ltd. marketing company from BP for approximately $220 million. We now own and operate 100 per cent of CrossAlta. The acquisition added an additional 27 Bcf of working gas storage capacity to our existing portfolio in Alberta.

BUSINESS RISKS

The following are risks specific to our energy business. See page 70 for information about general risks that affect the company as a whole.

Fluctuating power and natural gas market prices

Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta, and in our U.S. Power operations in New England and New York, are exposed to commodity price volatility. Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions and the price of natural gas, as power prices are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on earnings from these facilities. Our Coolidge Generating Station and our portfolio of assets in Eastern Canada are fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

To mitigate the impact of power price volatility in Alberta and the U.S. northeast, we sell a portion of our supply under medium to long-term sales contracts where contract terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if we have unexpected plant outages. This unsold supply is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

U.S. Power capacity payments

A portion of revenues earned by our power facilities in New England and a significant portion of revenues earned by Ravenswood are driven by capacity payments. Fluctuations in capacity prices can have a material impact on these businesses, particularly in New York. New York capacity prices are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to period review by the New York ISO and FERC. These parameters are determined for each capacity zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in forecasted demand. Capacity payments are also a function of plant availability which is discussed below.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

For facilities we do not operate, our purchase agreements include a financial remedy if a plant owner does not deliver as agreed. The Sundance and Sheerness PPAs, for example, require the producers to pay us market-based penalties if they cannot supply the amount of power we have agreed to buy.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability.

Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply.

Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets.

Hydrology

Our hydroelectric power generation facilities in the northeastern U.S. are subject to potential hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Execution, capital cost and permitting

Energy's construction programs are subject to execution, capital cost and permitting risks.

Corporate

OTHER INCOME STATEMENT ITEMS

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Comparable interest expense	**997**	1,046	754
Comparable interest income and other	**(86)**	(60)	(94)
Comparables income taxes	**472**	565	387
Net income attributable to non-controlling interests	**96**	107	93

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Comparable interest on long-term debt (including interest on junior subordinated notes)			
Canadian dollar-denominated	**513**	490	514
U.S. dollar-denominated	**740**	734	680
Foreign exchange	**–**	(7)	20
	1,253	1,217	1,214
Other interest and amortization expense	**44**	131	127
Capitalized interest	**(300)**	(302)	(587)
Comparable interest expense	**997**	1,046	754

Comparable interest expense this year was $49 million lower than 2011 primarily because of lower interest expense on amounts due to TransCanada and the impacts of debt repayments of $980 million and $1,272 million in 2012 and 2011. The decrease was partially offset by incremental interest on debt issues of US$1.0 billion in August 2012, US$500 million in March 2012 and $750 million in November 2011, a TC PipeLines, LP debt issue of US$350 million in June 2011 and the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest.

In 2011, comparable interest expense increased $292 million compared to 2010 because of a decrease in capitalized interest due to Keystone and Coolidge being placed in service in 2011 and Halton Hills being placed in service in late 2010. Comparable interest expense on U.S. dollar-denominated debt was higher in 2011 than 2010 due to new debt issues of US$1.0 billion in September 2010 and US$1.25 billion in June 2010. This was partially offset by the impact of a weaker U.S. dollar and the decrease in interest expense on Canadian dollar-denominated debt from debt maturities. In 2011, other interest and amortization expense was higher than 2010 because higher interest expense on amounts due to TransCanada, partially offset by gains instead of losses from changes in the fair value of derivatives used to manage our exposure to fluctuating interest rates.

Comparable interest income and other was $26 million higher in 2012 compared to 2011. This increase was mainly because of higher gains in 2012 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital balances. In 2011, comparable interest income and other was $34 million lower than 2010 because of lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations.

Comparable income taxes decreased $93 million in 2012 compared to 2011 mainly because of lower pre-tax earnings. In 2011, comparable income taxes increased $178 million from 2010 because of higher pre-tax earnings in 2011 and higher positive income tax adjustments in 2010 compared to 2011. In 2011 and 2010, we recorded a benefit in current income taxes with an offsetting provision in deferred income taxes due to bonus depreciation for U.S. income tax purposes on the Bison pipeline, which was placed in service in January 2011, and the Wood River/Patoka and Cushing Extension sections of Keystone which were placed in operational service in June 2010 and February 2011, respectively.

Net income attributable to non-controlling interests decreased this year primarily due to lower earnings from Great Lakes.

Financial condition

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

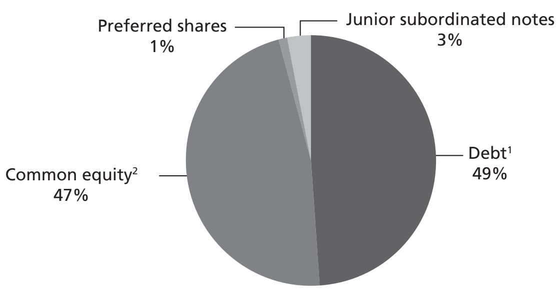
We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets, cash on hand and substantial committed credit facilities.

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

Capital structure

at December 31 (millions of $)	**2012**	**2011**
Notes payable	**2,275**	1,863
Due from TransCanada Corporation	**(985)**	(750)
Long-term debt	**18,913**	18,659
Junior subordinated notes	**994**	1,016
Cash and cash equivalents	**(537)**	(629)
Debt, net of cash and cash equivalents	**20,660**	20,159
Equity – controlling interests	**18,304**	17,932
Equity – non-controlling interests	**1,036**	1,076
Total equity	**19,340**	19,008
	40,000	39,167

Consolidated capital structure
at December 31, 2012



1 Net of cash and amounts due from TransCanada Corporation, and excluding junior subordinated notes.
2 Includes non-controlling interests in TC PipeLines, LP and Portland.

The following table shows how we have financed our business activities over the last three years. We continue to fund our extensive capital program through operations and, when needed, through capital markets securities issuances. Dividends paid on our common shares are included in financing activities.

at December 31 (millions of $)	**2012**	**2011**	**2010**
Cash flow from operating activities	**3,546**	3,567	2,817
Cash flow used in investing activities	**(3,256)**	(3,054)	(5,296)
Surplus (deficiency)	**290**	513	(2,479)
Cash flow (used in)/from financing activities	**(367)**	(536)	2,253
Net cash used	**(77)**	(23)	(226)

Our future liquidity will continue to be comprised of cash flow generated from our operations, committed credit facilities and our ability to access debt and equity markets. Our financial flexibility is further supported by opportunities for portfolio management including potential asset sales to TC PipeLines, LP.

Provisions of various trust indentures and credit arrangements that our subsidiaries are party to restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios. As at December 31, 2012, we were in compliance with all of our financial covenants.

Cash from operating activities

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Funds generated from operations	**3,259**	3,360	3,109
Decrease/(increase) in operating working capital	**287**	207	(292)
Net cash from operations	**3,546**	3,567	2,817

Funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations, excluding the timing effects of working capital changes. See page 12 for more information about non-GAAP measures.

At December 31, 2012, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $2.1 billion. This short-term deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to approximately $4.7 billion of unutilized, revolving bank lines, and
- our ongoing access to capital markets.

Cash used in investing activities

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Capital expenditures	**2,595**	2,513	4,376
Other investing activities	**661**	541	920

Our 2012 capital expenditures were primarily focused on expanding our Alberta System and construction of the Gulf Coast Project. Other investing activities in 2012 included our investment in Bruce Power capital projects.

We are developing quality projects under our current $12 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements resulting in very predictable future cash flows.

Cash (used in)/from financing activities

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Long-term debt issued, net of issue costs	**1,491**	1,622	2,371
Long-term debt repaid	**(980)**	(1,272)	(494)
Notes payable issued/(repaid), net	**449**	(224)	472
Dividends and distributions paid	**(1,361)**	(1,294)	(1,199)
Advance (to)/from parent, net	**(235)**	(2,090)	116
Equity financing activities	**269**	2,722	987

As at December 31, 2012, we had unused capacity of $1.25 billion and US$2.5 billion under our Canadian debt and U.S. debt shelf prospectuses to facilitate future access to the North American debt markets. In January 2013, we issued US$750 million of senior notes, reducing the capacity under our U.S. debt shelf prospectus to US$1.75 billion.

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 December 31, 2012, we had $5.3 billion in unsecured credit facilities, including:

Amount	Unused capacity	Borrower	For	Matures
$2.0 billion	$2.0 billion	TCPL	Committed, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	October 2017
US$1.0 billion	US$1.0 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, revolving credit facility that supports a TCPL USA U.S. dollar commercial paper program in the U.S.	October 2013
US$1.0 billion	US$1.0 billion	TransCanada Keystone Pipeline, LP	Committed, revolving, extendible credit facility that supports a U.S. dollar commercial paper program in Canada dedicated to funding a portion of Keystone	November 2013
US$300 million	US$300 million	TCPL USA	Committed, revolving credit facility that matures in first quarter 2013	February 2013
$1.0 billion	$373 million	TCPL	Demand lines for issuing letters of credit and as a source of additional liquidity. At December 31, 2012, we had outstanding $627 million in letters of credit under these lines	Demand

At December 31, 2012, our operated affiliates had $300 million of undrawn capacity on committed credit facilities.

Related Party Debt Financing

Related party debt consists of amounts due from TransCanada.

	Amount	For	Matures
Discount Notes	$2.9 billion	Discount notes issued by TransCanada; used for general corporate purposes.	2013
Credit Facility	$1.2 billion	Demand revolving credit facility arrangement with TransCanada; used for general corporate purposes.	n/a
Credit Facility	$0.7 billion	TransCanada's 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

Payments due (by period)

year ended December 31, 2012 (millions of $)	**Total**	**less than one year**	**1 - 3 years**	**3 - 5 years**	**more than 5 years**
Notes payable	2,275	2,275	–	–	–
Long-term debt (includes junior subordinated notes)	19,907	894	2,531	1,769	14,713
Operating leases (future annual payments for various premises, services and equipment, less sub-lease receipts)	747	74	145	155	373
Purchase obligations	8,126	3,012	2,261	1,131	1,722
Other long-term liabilities reflected on the balance sheet	381	9	19	21	332
	31,436	6,264	4,956	3,076	17,140

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Long-term debt

At the end of 2012, we had $18.9 billion of long-term debt and $1.0 billion of junior subordinated notes, compared to $18.7 billion of long-term debt and $1.0 billion of junior subordinated notes at December 31, 2011.

Total notes payable were $2.3 billion, compared to $1.9 billion at the end of 2011.

We attempt to spread out the maturity profile of our debt. The majority of our obligations mature beyond five years with an average term of 12 years.

At December 31, 2012, scheduled principal repayments and interest payments related to long-term debt were as follows:

Principal repayments

Payments due (by period)

year ended December 31, 2012 (millions of $)	**Total**	**less than one year**	**1 - 3 years**	**3 - 5 years**	**more than 5 years**
Notes payable	2,275	2,275	–	–	–
Long-term debt	18,913	894	2,531	1,769	13,719
Junior subordinated notes	994	–	–	–	994
	22,182	3,169	2,531	1,769	14,713

Interest payments

Payments due (by period)

year ended December 31, 2012 (millions of $)	**Total**	**less than one year**	**1 - 3 years**	**3 - 5 years**	**more than 5 years**
Long-term debt	15,377	1,154	2,125	1,908	10,190
Junior subordinated notes	3,443	63	126	126	3,128
	18,820	1,217	2,251	2,034	13,318

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 10 years.

Our commitments under the Alberta PPAs are considered operating leases. Future payments under these PPAs depend on plant availability, so we do not include them in our summary of future obligations. Our share of power purchased under the PPAs in 2012 was $303 million (2011 – $394 million; 2010 – $363 million).

We have subleased a part of the PPAs to third parties under terms and conditions similar to our own leases.

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements. At December 31, 2012, our operated affiliates had $0.3 billion of undrawn capacity on committed credit facilities.

Payments due (by period)

(not including pension plan contributions)

year ended December 31 (millions of $)	**Total**	**less than one year**	**1 - 3 years**	**3 - 5 years**	**more than 5 years**
Natural Gas Pipelines					
Transportation by others[1]	531	112	185	157	77
Capital expenditures[2,3]	1,322	797	439	86	-
Other	10	2	4	4	-
Oil Pipelines					
Capital expenditures[2,4]	1,732	1,271	461	-	-
Other	40	4	8	8	20
Energy					
Commodity purchases[5]	2,849	388	738	686	1,037
Capital expenditures[2,6]	62	41	11	10	-
Other[7]	1,539	377	395	180	587
Corporate					
Information technology and other	41	20	20	-	1
	8,126	3,012	2,261	1,131	1,722

1 Rates are primarily based on known 2012 levels. Demand rates may change after 2012. Purchase obligations are based on known or contracted demand volumes only and do not include commodity charges incurred when volumes flow.

2 Amounts are estimates and can vary depending on timing of construction and project enhancements. We expect to fund capital projects with cash from operations, by issuing senior debt and subordinated capital if required, and through portfolio management.

3 Primarily relate to the construction costs of the Alberta System expansion and other natural gas pipeline projects.

4 Primarily relate to Keystone XL and Gulf Coast.

5 Includes fixed and variable components but does not include derivatives. The variable components are estimates and can vary depending on plant production, market prices and regulatory tariffs.

6 Primarily relate to preliminary construction and development costs of Napanee.

7 Includes estimates of certain amounts that may change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation. This also includes the purchase obligation for Ontario Solar.

KEY PURCHASE COMMITMENTS

Ontario Solar

In December 2011, we announced an agreement to purchase nine Ontario solar projects with a combined capacity of 86 MW at a cost of approximately $476 million.

We will acquire each project under 20-year purchase plan agreements with the OPA (under Ontario's FIT program) once construction and acceptance testing are complete and operations have begun. We expect the projects to be acquired between first quarter 2013 and late 2014, subject to regulatory approvals.

GUARANTEES

Bruce Power

We and our partners, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of some of Bruce B's contingent financial obligations related to power sales agreements, a lease agreement and contractor services. The Bruce B guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it.

We and BPC have each severally guaranteed half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the OPA to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019.

At December 31, 2012, our share of the potential exposure under the Bruce A and B guarantees was estimated to be $897 million. The carrying amount of these guarantees was estimated to be $10 million. Our exposure under certain of these guarantees is unlimited.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities relating mainly to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging from 2013 to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2012 to range between $43 million to a maximum of $89 million. The carrying amount of these guarantees was estimated to be $7 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2013, we expect to make funding contributions of approximately $71 million to our defined benefit pension plans and other post-retirement benefit plans and approximately $33 million to our savings plan and defined contribution pension plans. We also expect to provide a $59 million letter of credit to a defined benefit plan in lieu of cash funding.

In 2012, we made funding contributions of approximately $90 million to our defined benefit pension plans and other post-retirement benefit plans and approximately $24 million to our savings plan and defined contribution pension plans. We also provided a $48 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2014. Based on current market conditions, we expect funding requirements for these plans to approximate 2012 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans increased to $99 million in 2012 from $68 million, mainly due to a lower discount rate used to measure the benefit obligation.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections, and
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, including making sure there are appropriate management systems in place to manage our risks, and adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Business interruption

Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events, could decrease revenues, increase costs or result in legal or other expenses, all of which could reduce our earnings. We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances. Losses that are not covered by insurance may have an adverse effect on our operations, earnings, cash flow and financial position.

Our reputation and relationships

Stakeholders, such as Aboriginal communities, communities, landowners, governments and government agencies, and environmental non-governmental organizations can have a significant impact on our operations, infrastructure developments and overall reputation. Our Stakeholder Engagement Framework – which we have implemented across the company – is our formal commitment to stakeholder engagement. Our four core values – integrity, collaboration, responsibility and innovation – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders.

Execution and capital costs

Investing in large infrastructure projects involves substantial capital commitments, based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers, in exchange for the potential benefit they will realize when the project is finished. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun risk which may decrease our return on these projects.

Cybersecurity

Security threats (including cybersecurity threats) and related disruptions can have a negative impact on our business. We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions that affect operations. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.

Pipeline abandonment costs
The NEB's Land Matters Consultation Initiative (LMCI) is an initiative that will require all Canadian pipeline companies regulated by the NEB to set aside funds to cover future abandonment costs.

The NEB provided several key guiding principles during the LMCI process, including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the individual pipeline systems. The first hearing addressing the basis and the approach to the determination of specific pipeline abandonment cost estimates was held in October 2012. Additional hearings and the Board's decisions are scheduled to be completed by June 2014, which implies that 2015 would be the earliest that the collection of funds could begin.

Health, safety and environment

Our approach to managing health and safety and protecting the environment is guided by our HSE commitment statement, which outlines guiding principles for a safe and healthy environment for our employees, contractors and the public, and expresses our commitment to protect the environment.

We are committed to continually improving our occupational health and safety performance, and to promoting safety on and off the job, in the belief that all occupational injuries and illnesses are preventable. We try to work with companies and contractors who share our commitment and approach. We also have environmental controls in place, including physical design, programs, procedures and processes, to help manage the environmental risk factors we are exposed to, including spill and release response.

Management monitors HSE performance and is kept informed about operational issues and initiatives through formal incident and issues management processes and regular reporting.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. We expect to spend approximately $402 million in 2013 for pipeline integrity on the pipelines we operate, an increase of $90 million over 2012 primarily due to increased levels of in-line pipeline inspection on all systems as well an increased amount of pipe replacement required due to population encroachment on the pipelines. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on our earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures also have no impact on our earnings. Our pipeline safety record in 2012 continued to be better than industry benchmarks. We experienced no pipeline breaks in 2012 on our operated pipelines.

Spending associated with public safety on the Energy assets is focused primarily on our hydro dams and associated equipment.

Our main environmental risks are:
- air and greenhouse gas (GHG) emissions
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals, hazardous materials, and
- compliance with corporate and regulatory policies and requirements.

Environmental compliance and liabilities
Our facilities are subject to stringent federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges

and waste management. Our facilities are required to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders for future operations.

We continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

It is not possible to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) can change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2012, we had accrued approximately $37 million related to these obligations ($49 million at the end of 2011). This represents the amount that we have estimated that we will need to manage our currently indentified environmental liabilities. We believe that the Company has considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts. We adjust this reserve quarterly to account for changes in liabilities.

Emissions regulation risk

We own assets in four regions where there are regulations to address industrial GHG emissions. We have procedures in place to comply with these regulations, including:

- under the Specified Gas Emitters Regulation in Alberta, industrial facilities with GHG emissions above a certain threshold have to reduce their emissions by 12 per cent below an average intensity baseline. Our Alberta System facilities and Sundance and Sheerness (the coal-fired power facilities we have PPAs with) are subject to this regulation. We recover compliance costs on the Alberta System through the tolls our customers pay. A portion of the compliance costs for Sundance and Sheerness are recovered through market pricing and contract flow through provisions. We recorded $15 million for the Alberta Specified Gas Emitters Regulation in 2012, after contracted cost recovery.
- B.C. has imposed a tax on carbon dioxide (CO_2) emissions from fossil fuel combustion since 2008. We recover the compliance costs for our compressor and meter stations through the tolls our customers pay. In 2012, we recorded $5 million for the B.C. carbon tax. The cost per tonne of CO_2 increased from $25 to $30 beginning in July 2012
- Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators beginning January 2009. This program applies to both the Ravenswood and Ocean State Power generation facilities. These costs are generally recovered through the power market, and do not have a significant net impact on our results. We recorded $3 million in 2012 to participate in quarterly auctions of allowances under RGGI

- the natural gas distributor in Québec collects a hydrocarbon royalty on behalf of the provincial government through a green fund charge. We recorded less than $1 million for the hydrocarbon royalty related to our Bécancour facility in 2012.

In September 2012, the Government of Canada finalized a GHG regulation for the coal-fired electricity sector. Starting in July 2015, companies will have to meet a new GHG emissions performance standard for new and existing units (equal to approximately the emissions of a combined cycle natural gas-fired electrical generation unit). We do not believe the regulation poses a significant risk or will have a significant financial impact, and it may present opportunities for new power generation investment.

There are also federal, regional, state and provincial initiatives in development. While economic events may significantly affect the scope and timing of new regulations, we anticipate that most of our facilities will be subject to future regulations to manage industrial GHG emissions.

As described in the Business interruption section, above, we have a set of procedures in place to manage our response to natural disasters like forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes, regardless of how they are caused. The procedures, which are included in the Operating Procedures in our Incident Management System, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the impact any operational issues caused by a natural disaster might have on the environment.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity 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. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in large infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold.

We use derivative contracts to assist in managing our exposure to market risk, including:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- options – agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

We assess contracts we use to manage market risk to determine whether a contract, or a portion of it, meets the definition of a derivative.

Commodity price risk

We are exposed to changes in commodity prices, especially electricity and natural gas, and use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

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. operations continue to grow, our exposure to changes in currency rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We use foreign exchange derivatives to manage other foreign exchange transactions, including foreign exchange exposures that arise on some of our regulated assets. We defer some of the realized gains and losses on these derivatives as regulatory assets and liabilities until we recover or pay them to shippers according to the terms of the shipping agreements.

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

2012	1.00
2011	0.99
2010	1.03

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 12 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2012**	**2011**	**2010**
U.S. and International Natural Gas Pipelines comparable EBIT	**660**	761	683
U.S. Oil Pipelines comparable EBIT	**363**	301	-
U.S. Power comparable EBIT	**88**	164	187
Interest on U.S. dollar-denominated long-term debt	**(740)**	(734)	(680)
Capitalized interest on U.S. capital expenditures	**124**	116	290
U.S. non-controlling interests and other	**(192)**	(192)	(164)
	303	416	316

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(liability)

	2012		2011	
December 31 (millions of $)	**Fair value**[1]	**Notional or principal amount**	**Fair value**[1]	**Notional or principal amount**
U.S. dollar cross-currency swaps (maturing 2013 to 2019)	**82**	**US$3,800**	93	US$3,850
U.S. dollar forward foreign exchange contracts (maturing 2013)	**-**	**US$250**	(4)	US$725
	82	**US$4,050**	89	US$4,575

1 Fair values equal carrying values.
2 Consolidated net income in 2012 included net realized gains of $30 million (2011 – gains of $27 million) related to the interest component of cross-currency swap settlements.

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

at December 31 (billions of $)	**2012**	**2011**
Carrying value	**$11.1 (US$11.2)**	$10 (US$9.8)
Fair value	**$14.3 (US$14.4)**	$12.7 (US$12.5)

Fair value of derivatives used to hedge our U.S. dollar investment in foreign operations

at December 31 (millions of $)	**2012**	**2011**
Other current assets	**71**	79
Intangibles and other	**47**	66
Accounts payable	**6**	15
Deferred amounts	**30**	41

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:
- accounts receivable
- portfolio investments
- the fair value of derivative assets
- notes receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:
- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances, like guarantees, letters of credit or cash, when it is available and we believe it is necessary.

There is no guarantee, however, these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2012 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $259 million with one counterparty ($274 million in 2011). 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.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 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.

See page 63 financial condition for more information about our liquidity.

Dealing with legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. The most significant this year were the TransAlta Sundance A claims, which were resolved through a binding arbitration process that resulted in a decision in July 2012. See page 57 for more information.

While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. We are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as at December 31, 2012, as required by the Canadian securities regulatory authorities and by the SEC.

They concluded that:

- our disclosure controls and procedures were effective in providing reasonable assurance that the information we are required to disclose in reports we file with or send to securities regulatory authorities is compiled and communicated to management (including the President and CEO and the CFO as required) so management can make timely decisions about our disclosure and information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.
- our internal control over financial reporting is effective as it is reliable and provides reasonable assurance that our financial reporting and the preparation of our consolidated financial statements for external reporting purposes is in accordance with U.S. GAAP. Management conducted this evaluation based on the framework in *Internal control – integrated framework*, a publication issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Internal control over financial reporting is a process designed by or supervised by management and involves our Board, Audit Committee, management and other employees.

There was no change in our internal control over financial reporting in 2012 that had or is likely to have a material impact. Note that no matter how well-designed, internal control over financial reporting has inherent limitations, and management can only provide reasonable assurance about the reliability of the preparation and presentation of financial statements for external reporting.

CEO AND CFO CERTIFICATIONS

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2012 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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 judgment. We also regularly assess the assets and liabilities themselves.

You can find a summary of our significant accounting policies in Note 2 to the consolidated financial statements for the year ended December 31, 2012.

The following accounting policies and estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements.

Rate-regulated accounting

Under U.S. GAAP, a company qualifies to use rate-regulated accounting when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products, and
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines we account for using rate-regulated accounting meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under U.S. GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	**2012**	**2011**
Regulatory assets		
Regulatory assets	**1,629**	1,684
Other current assets	**178**	178
Regulatory liabilities		
Regulatory liabilities	**268**	297
Accounts payable	**100**	139

Depreciation and amortization

Total depreciation and amortization expense in 2012 was $1,375 million (2011 – $1,328 million; 2010 – $1,160 million). Each segment has recorded their portion of this amount.

We depreciate our plant, property and equipment on a straight-line basis over their estimated useful lives once they are ready for their intended use. We estimate their useful lives based on third-party engineering studies, experience and industry practice. When changes to the estimated service lives occur, the change is applied prospectively over the remaining expected useful life, which would result in a change to the depreciation expense in future periods.

We use various rates to calculate the depreciation of different kinds of company assets:

Asset type	Annual rate of depreciation
Natural gas pipeline and compression equipment	1% – 6%
Oil pipeline and pumping equipment	Approximately 2% – 2.5%
Metering and other plant equipment	Various rates
Major power generation and natural gas storage plant, equipment and structures in the energy business	2% – 20%
Other energy equipment	Various rates
Corporate plant, property and equipment	3% – 20%

Natural Gas Pipelines

Regulators for our natural gas pipelines business approve our depreciation rates, which allows us to recover the expense of depreciation from our customers as a cost of providing services. As a result, changes in the estimate of the useful lives of plant, property and equipment have no material impact on net income but have a direct effect on funds generated from operations.

Energy

In addition to the depreciation of our energy assets, we deferred and amortize the initial payment for our PPAs on a straight-line basis over the terms of the contracts, which expire in 2017 and 2020. We included a PPA amortization expense of $52 million in Energy's depreciation and amortization expense for 2010 through 2012.

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value, and we calculate an impairment loss to recognize this.

Goodwill

As at December 31, 2012, we reported total goodwill of $3.5 billion (2011 – $3.5 billion).

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit, including its goodwill, to its book value. If fair value is less than book value, we consider our goodwill to be impaired.

2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting units from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

- discount rates
- commodity and capacity prices
- market supply and demand assumptions
- growth opportunities
- output levels
- competition from other companies, and
- regulatory changes.

If our assumptions change significantly, our requirement to record an impairment charge could also change. There is a risk that adverse changes in key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. These assumptions could be negatively impacted by factors including weather, levels of natural gas in storage, the outcome of the 2013 Natural Gas Act Section 4 general rate case and the outcome of the Canadian Restructuring Proposal. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$266 million at December 31, 2012 (2011 – US$266 million).

Employee post-retirement benefits

We sponsor defined benefit pension plans, defined contribution plans, a savings plan and other post-retirement benefit plans. We expense contributions we make to these plans, except for our defined benefit plans, in the period we make contributions. We estimate the cost of the defined benefit plans and other post-retirement benefits actuarially, based on service and management's best estimate of expected plan investment performance, salary increases, employee retirement age and expected health care costs. Changes in these estimates could result in a change in the expense and liability amounts.

We measure the assets in the defined benefit plans at fair value, and calculate our expected returns using market-related values based on a five-year moving average for all of the defined benefit plans' assets on a plan-by-plan basis. We amortize past service costs over the expected average remaining service life of the employees, and amortize adjustments arising from plan amendments on a straight-line basis over the average remaining service period of employees active at the date of amendment. Future pension expense and funding could be impacted by changes in plan asset returns, assumed discount rates and other factors dependent on the participants of our plans. We recognize the overfunded or underfunded status of the defined benefit plans as an asset or liability on the balance sheet, and recognize changes in this status through other comprehensive income (loss) (OCI) in the year the change occurs. When net actuarial gains or losses are higher than 10 per cent of the benefit obligation (or the market-related value of the plan's assets, whichever is higher), we amortize the difference in accumulated other comprehensive income (loss)/income (AOCI) over the average remaining service period of the active employees.

In some of our regulated operations, we can recover some post-retirement benefit amounts through tolls as benefits are funded.

We record unrecognized gains and losses, or changes in actuarial assumptions related to our post-retirement benefit plans, as either regulatory assets or liabilities, and amortize them on a straight-line basis over the average remaining service life of active employees.

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the asset retirement obligation in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

Canadian regulated pipelines

The NEB's LMCI is an initiative for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs.

As part of the guidance provided by the initiative, the NEB has stated that abandonment costs are a legitimate cost of providing pipeline service and should be recoverable (with NEB approval) from system users.

In May 2009, the NEB established several filing deadlines for pipeline companies, including deadlines for

- estimating their pipeline abandonment costs
- proposing how they will collect these funds (through tolls or another satisfactory method)
- proposing how they will set aside the funds they collect.

We filed estimates for our regulated Canadian oil and natural gas pipelines in November 2011 as required. Based on the NEB's direction in 2009, the soonest we could begin collecting funds through cost of service tolls would be 2015. The specific impacts on tolls will be the subject of an NEB filing expected in May 2013.

FINANCIAL INSTRUMENTS

All financial instruments, including both derivative and non-derivative financial 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 purchases and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

We apply hedge accounting to derivative instruments that qualify. We recognize three kinds of hedges including fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Changes in fair value are recorded according to the accounting rules that apply as outlined in the table below. Hedge accounting is discontinued prospectively if the hedging relationship is no longer effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

Type of hedge	How we record derivative instruments in hedging relationships
Fair value hedge	The carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. To the extent that the hedging relationship is effective, changes in the fair value of the hedged item are offset by changes in the fair value of the hedging derivative, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in interest income and other and interest expense. When fair value hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments are amortized to net income over the remaining term of the original hedging relationship.
Cash flow hedge	We recognize the effective portion of the change in the fair value of the hedging derivative initially in OCI, and any ineffective portion is recognized in net income in the same financial statement category as the underlying transaction. When cash flow hedge accounting is discontinued, the amounts previously in AOCI are reclassified to revenues, interest expense and interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or the original hedged item settles. When the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur, we immediately reclassify any gains and losses from AOCI to net income.
Hedge of foreign currency exposure for net investments in foreign operations	We recognize the effective portion of foreign exchange gains and losses on the hedging instruments in OCI and the ineffective portion in interest income and other.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment, and the changes in fair value are recorded in net income in the period of change. This may expose us to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period; however, we enter into the arrangements as they are considered to be effective economic hedges.

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

The recognition of gains and losses on the derivatives for the 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 rate regulated accounting, 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 values

Non-derivative Instruments

Certain financial instruments including cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. 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 based on quoted market prices for the same or similar debt instruments. The fair value of available for sale assets has been calculated using quoted market prices where available.

Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair values of power and natural gas derivatives 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 derivatives, notes receivable and long-term debt.

Non-derivative financial instruments summary

	2012		2011	
at December 31 (millions of $)	**Carrying amount**[1]	**Fair value**[2]	**Carrying amount**[1]	**Fair value**[2]
Financial assets				
Cash and cash equivalents	**537**	**537**	629	629
Accounts receivable and other[3]	**1,324**	**1,373**	1,378	1,422
Due from TransCanada Corporation	**985**	**985**	750	750
Available for sale assets[3]	**44**	**44**	23	23
	2,890	**2,939**	2,780	2,824
Financial liabilities[4]				
Notes payable	**2,275**	**2,275**	1,863	1,863
Accounts payable and deferred amounts[5]	**1,535**	**1,535**	1,330	1,330
Accrued interest	**370**	**370**	367	367
Long-term debt	**18,913**	**24,573**	18,659	23,757
Junior subordinated notes	**994**	**1,054**	1,016	1,027
	24,087	**29,807**	23,235	28,344

1 Recorded at amortized cost, except for US$350 million (2011 – US$350 million) of long-term debt that is attributed to hedged risk and recorded at fair value. This debt, which is recorded at fair value on a recurring basis, is classified in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

2 The fair value measurement of financial assets and liabilities recorded at amortized cost for which fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

3 At December 31, 2012, the consolidated balance sheet included financial assets of $1.1 billion (2011 – $1.1 billion) in accounts receivable, $40 million (2011 – $41 million) in other current assets and $240 million (2011 – $247 million) in intangible and other assets.

4 Consolidated net income in 2012 included losses of $10 million (2011 – losses of $13 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationship on US$350 million of debt at December 31, 2012 (2011 – US$350 million). There were no other unrealized gains or losses from fair value adjustments to non-derivative financial instruments.

5 At December 31, 2012, the consolidated balance sheet included financial liabilities of $1.5 billion (2011 – $1.2 billion) in accounts payable, and $38 million (2011 – $137 million) in other long-term liabilities.

Contractual repayments of non-derivative financial liabilities – Principal and interest payments due by period

at December 31, 2012 (millions of $)	Total	2013	2014 and 2015	2016 and 2017	2018 and thereafter
Notes payable	2,275	2,275	-	-	-
Long-term debt	18,913	894	2,531	1,769	13,719
Junior subordinated notes	994	-	-	-	994
	22,182	3,169	2,531	1,769	14,713

Interest payments on non-derivative financial liabilities – Principal and interest payments due by period

at December 31, 2012 (millions of $)	Total	2013	2014 and 2015	2016 and 2017	2018 and thereafter
Long-term debt	15,377	1,154	2,125	1,908	10,190
Junior subordinated notes	3,443	63	126	126	3,128
	18,820	1,217	2,251	2,034	13,318

2012 Derivative instruments summary

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

(millions of $, except where noted)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2]				
Assets	$139	$88	$1	$14
Liabilities	$(176)	$(104)	$(2)	$(14)
Notional values				
Volumes[3]				
Purchases	31,135	83	-	-
Sales	31,066	65	-	-
Canadian dollars	-	-	-	620
U.S. dollars	-	-	US1,408	US200
Cross-currency	-	-	-	-
Net unrealized (losses)/gains in the year[4]	$(30)	$2	$(1)	$-
Net realized gains/(losses) in the year[4]	$5	$(10)	$26	$-
Maturity dates	2013 – 2017	2013 – 2016	2013	2013 – 2016
Derivative instruments in hedging relationships[5,6]				
Fair values[2]				
Assets	$76	$–	$–	$10
Liabilities	$(97)	$(2)	$(38)	$–
Notional values				
Volumes[3]				
Purchases	15,184	1	-	-
Sales	7,200	-	-	-
U.S. dollars	-	-	US12	US350
Cross-currency	-	-	136/US100	-
Net realized (losses)/gains in the year[4]	$(130)	$(23)	$-	$7
Maturity dates	2013 – 2018	2013	2013 – 2014	2013 – 2015

1 All derivative instruments held for trading have been entered into for risk management purposes and are subject to our risk management strategies, policies and limits. This includes 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 our exposure to market risk.

2 Fair values equal carrying values.

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

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in 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.

5 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 $10 million and a notional amount of US$350 million. In 2012, net realized gains on fair value hedges were $7 million and were included in interest expense. In 2012, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 In 2012, 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.

The anticipated timing of settlement of the derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates at December 31, 2012. Settlements will vary based on the actual value of these factors at the date of settlement.

Anticipated timing of settlement – derivative instruments

at December 31, 2012 (millions of $)	Total	2013	2014 and 2015	2016 and 2017	2018 and thereafter
Anticipated timing of settlement – derivative contracts					
Derivative instruments held for trading					
Assets	242	141	99	2	-
Liabilities	(296)	(175)	(117)	(4)	-
Derivative instruments in hedging relationships					
Assets	204	117	85	2	-
Liabilities	(173)	(105)	(55)	(11)	(2)
	(23)	(22)	12	(11)	(2)

2011 Derivative instruments summary

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

(millions of $, except where noted)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional values				
Volumes[3]				
Purchases	21,905	103	-	-
Sales	21,334	82	-	-
Canadian dollars	-	-	-	684
U.S. dollars	-	-	US1,269	US250
Cross-currency	-	-	47/US37	-
Net unrealized (losses)/gains in the year[4]	$(2)	$(50)	$(4)	$1
Net realized gains/(losses) in the year[4]	$42	$(74)	$10	$1
Maturity dates	2012 – 2016	2012 – 2016	2012	2012 – 2016
Derivative instruments in hedging relationships[5,6]				
Fair values[2]				
Assets	$16	$3	$-	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional values				
Volumes[3]				
Purchases	17,188	8	-	-
Sales	8,061	-	-	-
U.S. dollars	-	-	US73	US600
Cross-currency	-	-	136/US100	-
Net realized losses in the year[4]	$(165)	$(17)	$-	$(16)
Maturity dates	2012 – 2017	2012 – 2013	2012 – 2014	2012 – 2015

1 All derivative instruments held for trading have been entered into for risk management purposes and are subject to our 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 our exposures to market risk.

2 Fair values equal carrying values.

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

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative 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.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in interest expense. In 2011, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 In 2011, 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.

Balance sheet presentation of derivative financial instruments

The fair value of the derivative financial instruments on the balance sheet.

at December 31 (millions of $)	**2012**	**2011**
Current		
Other current assets	**259**	361
Accounts payable and other	**(283)**	(485)
Long term		
Intangibles and other assets	**187**	202
Other long-term liabilities	**(186)**	(349)

Derivatives in cash flow hedging relationships

The components of OCI related to derivatives in cash flow hedging relationships.

Cash flow hedges[1]

year ended December 31 (millions of $, pre-tax)		**Power**		**Natural gas**		**Foreign exchange**		**Interest**
	2012	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Change in fair value of derivative instruments recognized in OCI (effective portion)	**83**	(263)	**(21)**	(59)	**(1)**	5	**-**	(1)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**147**	81	**54**	100	**-**	-	**18**	43
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**7**	-	**-**	-	**-**	-	**-**	-

1 No amounts have been excluded from the assessment of hedge effectiveness.

Credit risk related contingent features

Derivatives 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). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2012, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $37 million (2011 – $110 million), with collateral provided in the normal course of business of nil (2011 – $28 million).

If the credit-risk-related contingent features in these agreements were triggered on December 31, 2012, we would have been required to provide additional collateral of $37 million (2011 – $82 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair value hierarchy

Financial assets and liabilities that are recorded at fair value are required to be categorized into three levels based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that we have 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.
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. Inputs into the model 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 would result in a lower fair value measurement of contracts included in Level III.

Financial assets and liabilities measured on a recurring basis
Current and non-current portions

	Quoted prices in active markets (Level I)[1]		Significant other observable inputs (Level II)[1,2]		Significant unobservable inputs (Level III)[2]		Total	
at December 31 (millions of $, pre-tax)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Derivative instrument assets:								
Interest rate contracts	**-**	-	**24**	35	**-**	-	**24**	35
Foreign exchange contracts	**-**	-	**119**	142	**-**	-	**119**	142
Power commodity contracts	**-**	-	**213**	201	**2**	-	**215**	201
Gas commodity contracts	**75**	124	**13**	55	**-**	-	**88**	179
Derivative instrument liabilities:								
Interest rate contracts	**-**	-	**(14)**	(23)	**-**	-	**(14)**	(23)
Foreign exchange contracts	**-**	-	**(76)**	(102)	**-**	-	**(76)**	(102)
Power commodity contracts	**-**	-	**(269)**	(454)	**(4)**	(15)	**(273)**	(469)
Gas commodity contracts	**(95)**	(208)	**(11)**	(26)	**-**	-	**(106)**	(234)
Non-derivative financial instruments:								
Available-for-sale assets	**44**	23	**-**	-	**-**	-	**44**	23
	24	(61)	**(1)**	(172)	**(2)**	(15)	**21**	(248)

1 Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in 2012 and 2011.

2 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 become available, they are transferred out of Level III and into Level II. There were no transfers out of Level II and into Level III in 2012 and 2011.

Net change in the Level III fair value category

(millions of $, pre-tax)	**Derivatives[1,2]**
Balance at December 31, 2010	(8)
New contracts	1
Settlements	2
Transfers out of Level III	3
Total gains/(losses) included in OCI	(13)
Balance at December 31, 2011	(15)
Settlements	**(1)**
Transfers out of Level III	**(21)**
Total gains included in net income	**11**
Total gains/(losses) included in OCI	**24**
Balance at December 31, 2012	**(2)**

1 The fair value of derivative assets and liabilities is presented on a net basis.
2 At December 31, 2012, there were unrealized gains included in net income attributed to derivatives that were still held at the reporting date of $1 million (2011 – 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 at December 31, 2012.

ACCOUNTING CHANGES

Changes in accounting policies for 2012

Fair value measurement

We adopted the Financial Accounting Standards Board's (FASB) accounting standards update on fair value measurements, and increased our qualitative and quantitative disclosures about Level III measurements effective January 1, 2012.

Intangibles – goodwill

We adopted the FASB accounting standards update on testing goodwill for impairment, and changed our accounting policy related to testing goodwill for impairment effective January 1, 2012. We now assess qualitative factors affecting the fair value of a reporting unit compared to its carrying amount first, before deciding whether to proceed to the two-step quantitative impairment test. The adoption of this standard and our assessment of goodwill in 2012 did not result in any finding of impairment. For further information see impairment of long-lived assets and goodwill on page 78.

Future accounting changes

Balance sheet offsetting/netting

In December 2011, the FASB issued an amendment requiring companies to provide disclosure that will help readers understand the effect, or potential effect, of netting arrangements on the company's financial position. This guidance, which will be effective for annual periods beginning on or after January 1, 2013, will require us to include additional information about financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting arrangement, or other similar agreement.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2012	Fourth	Third	Second	First
Revenues	**2,089**	**2,126**	**1,847**	**1,945**
Net income attributable to common shares	**315**	**379**	**282**	**362**
Share statistics				
Net income per share – basic and diluted	**$0.43**	**$0.51**	**$0.38**	**$0.49**

2011	Fourth	Third	Second	First
Revenues	2,015	2,043	1,851	1,930
Net income attributable to common shares	372	379	348	404
Share statistics				
Net income per share – basic and diluted	$0.54	$0.56	$0.52	$0.60

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In Natural Gas Pipelines, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

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

In Oil 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 for natural gas and energy
- 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.

Factors affecting financial information by quarter

Fourth quarter 2012

- EBIT included net unrealized losses of $17 million pre-tax ($12 million after-tax) from certain risk management activities.

Third quarter 2012

- EBIT included net unrealized gains of $31 million pre-tax ($20 million after tax) from certain risk management activities.

Second quarter 2012

- EBIT included a $50 million pre-tax charge ($37 million after tax) from the Sundance A PPA arbitration decision, and net unrealized losses of $14 million pre-tax ($13 million after tax) from certain risk management activities.

First quarter 2012

- EBIT included net unrealized losses of $22 million pre-tax ($11 million after tax) from certain risk management activities.

Fourth quarter 2011

- EBIT included net unrealized after-tax gains of $11 million ($13 million pre-tax) resulting from certain risk management activities.

Third quarter 2011

- EBIT included net unrealized losses of $43 million pre-tax ($30 million after tax) resulting from certain risk management activities.

Second quarter 2011

- EBIT included net unrealized losses of $3 million pre-tax ($2 million after tax) resulting from certain risk management activities.

First quarter 2011

- EBIT included net unrealized losses of $19 million pre-tax ($12 million after tax) resulting from certain risk management activities.
- Natural Gas Pipelines EBIT included incremental earnings from Bison, which we placed in service in January 2011.
- Oil Pipelines began recording EBIT for the Keystone Pipeline System in February 2011.

FOURTH QUARTER 2012 HIGHLIGHTS

Reconciliation of non-GAAP measures

Three months ended December 31 (unaudited) (millions of $)	**2012**	**2011**
Comparable EBITDA	**1,052**	1,120
Depreciation and amortization	**(343)**	(341)
Comparable EBIT	**709**	779
Other income statement items		
Comparable interest expense	**(252)**	(276)
Comparable interest income and other	**20**	8
Comparable income taxes	**(122)**	(117)
Net income attributable to non-controlling interests	**(23)**	(28)
Preferred share dividends	**(5)**	(5)
Comparable earnings	**327**	361
Specific item (net of tax)		
Risk management activities[1]	**(12)**	11
Net income attributable to common shares	**315**	372
Comparable interest expense	**(252)**	(276)
Specific item:		
Risk management activities	**-**	-
Interest expense	(252)	(276)
Comparable interest income and other	**20**	8
Specific item		
Risk management activities[1]	**(5)**	35
Interest income and other	**15**	43
Comparable income taxes	**(122)**	(117)
Specific item		
Risk management activities[1]	**5**	(2)
Income taxes expense	**(117)**	(119)

1 Three months ended December 31

(unaudited) (millions of $)	**2012**	**2011**
Risk management activities gains/(losses):		
Canadian Power	**(6)**	-
U.S. Power	**(5)**	(33)
Natural Gas Storage	**(1)**	11
Interest rate	**-**	-
Foreign exchange	**(5)**	35
Income taxes attributable to risk management activities	**5**	(2)
Risk management activities	**(12)**	11

EBITDA and EBIT by Business Segment

Three months ended December 31, 2012 (unaudited) (millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**690**	**172**	**222**	**(32)**	**1,052**
Depreciation and amortization	**(236)**	**(36)**	**(68)**	**(3)**	**(343)**
Comparable EBIT	**454**	**136**	**154**	**(35)**	**709**

Three months ended December 31, 2011 (unaudited) (millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	716	179	254	(29)	1,120
Depreciation and amortization	(235)	(35)	(67)	(4)	(341)
Comparable EBIT	481	144	187	(33)	779

Highlights by line item

Comparable earnings

Comparable earnings in fourth quarter 2012 were $327 million compared to $361 million for the same period in 2011. Comparable earnings excluded net unrealized after-tax losses of $12 million ($17 million pre-tax) (2011 – $11 million after-tax gains; $13 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable earnings decreased $34 million in fourth quarter 2012 compared to the same period in 2011 and included the following:

- decreased Canadian Natural Gas Pipelines net income primarily due to lower earnings from the Canadian Mainline which excluded incentive earnings and reflected a lower investment base;
- decreased U.S. and International Natural Gas Pipelines comparable EBIT primarily due to lower revenues on Great Lakes due to uncontracted capacity and lower rates as well as lower revenues and higher costs on ANR;
- decreased Oil Pipelines comparable EBIT which reflected increased business development activity and related costs;
- decreased Energy comparable EBIT as a result of the Sundance A PPA force majeure as well as decreases and lower equity earnings from ASTC Power Partnership resulting from an unfavourable Sundance B PPA arbitration decision. These decreases were partially offset by higher contributions from Eastern Power due to incremental earnings from Cartier Wind as well as from U.S. Power due to higher generation volumes and realized power and capacity prices in New York; and
- increased comparable interest income and other due to higher realized gains in 2012 compared to losses in 2011 on derivatives used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Net income attributable to common shares

Our net income attributable to common shares was $315 million in fourth quarter 2012 compared to $372 million for the same period in 2011.

Highlights by business segment

Natural Gas Pipelines

Natural Gas Pipelines comparable EBIT was $454 million in fourth quarter 2012 compared to $481 million for the same period in 2011. This decrease was primarily due to lower earnings from the Canadian Mainline which excluded incentive earnings and reflected a lower investment base and lower contributions from Great Lakes and ANR partially offset by higher earnings from the Alberta System.

Natural Gas Pipelines business development comparable EBITDA was $4 million in fourth quarter 2012 compared to $15 million for the same period in 2011. This decrease was primarily related to reduced activity in 2012 for the Alaska Pipeline Project.

Canadian Pipelines

Canadian Mainline's net income of $47 million in fourth quarter 2012 decreased $13 million compared to the same period in 2011. Canadian Mainline's net income for fourth quarter 2011 included incentive earnings earned under an incentive arrangement in the five-year tolls settlement that expired December 31, 2011. In the absence of a NEB decision with respect to the 2012-2013 tolls application, Canadian Mainline's 2012 quarterly results reflected the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent and exclude incentive earnings. In addition, Canadian Mainline's fourth quarter 2012 net income decreased as a result of a lower average investment base compared to the prior year.

The Alberta System's net income of $55 million in fourth quarter 2012 increased by $4 million compared to the same period in 2011. The increase in 2012 net income was from a higher average investment base and was partially offset by lower incentive earnings.

Canadian Mainline's comparable EBITDA for fourth quarter 2012 of $250 million decreased $12 million compared to $262 million in the same period in 2011. The Alberta System's comparable EBITDA was $195 million for fourth quarter 2012 compared to $185 million in the same period in 2011. EBITDA from the Canadian Mainline and the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis and, therefore, do not impact net income.

U.S. Pipelines

ANR's comparable EBITDA in fourth quarter 2012 of US$63 million decreased US$10 million compared to the same period in 2011. The decrease was primarily due to lower transportation revenues and higher costs.

Great Lakes' comparable EBITDA for fourth quarter 2012 of US$11 million decreased US$9 million compared to the same period in 2011. The decrease was primarily the result of lower transportation revenue due to uncontracted capacity and lower rates compared to the same period in 2011.

Natural Gas Pipelines' business development comparable EBITDA loss from business development activities decreased $11 million for fourth quarter 2012 compared to the same period in 2011. The decrease in business development costs were primarily related to reduced activity in 2012 for the Alaska Pipeline Project.

Oil Pipelines

Oil Pipelines' comparable EBIT in fourth quarter 2012 was $136 million compared to $144 million for the same period in 2011. This decrease primarily reflected increased business development activity and related costs. The Keystone Pipeline System's comparable EBITDA of $180 million in fourth quarter 2012 is consistent with the same period in 2011.

Energy

Energy's comparable EBIT was $154 million in fourth quarter 2012 compared to $187 million in fourth quarter 2011. This decrease was a result of the Sundance A PPA force majeure as well as lower equity earnings from ASTC Power Partnership resulting from an unfavourable Sundance B PPA arbitration decision. These decreases were partially offset by higher contributions from Eastern Power due to incremental earnings from new assets being placed in service at Cartier Wind as well as from U.S. Power due to higher generation volumes and realized power and capacity prices in New York.

Western Power's comparable EBITDA of $84 million in fourth quarter 2012 decreased $58 million compared to the same period in 2011 primarily due to the Sundance A PPA force majeure and decreased equity earnings from the ASTC Power Partnership as a result of the Sundance B PPA arbitration decision.

Western Power's power revenues of $158 million in fourth quarter 2012 decreased $61 million compared to the same period in 2011 primarily due to the Sundance A PPA force majeure.

Eastern Power's comparable EBITDA of $94 million in fourth quarter 2012 increased $12 million compared to the same period in 2011. The increase was primarily due to incremental Cartier Wind earnings from phases one and two of Gros-Morne which were placed in service in November 2011 and November 2012, respectively, and Montagne-Sèche which was placed in service in November 2011, partially offset by lower Bécancour contractual earnings.

Our loss from Bruce A increased $39 million to a loss of $54 million in fourth quarter 2012 compared to the same period in 2011. This increase was primarily due to lower volumes and higher operating costs resulting from higher outage days. These increases were partially offset by incremental volumes and earnings from Units 1 and 2 which were returned to service on October 22 and October 31, respectively.

Our equity income from Bruce B increased $32 million to $46 million in fourth quarter 2012 compared to the same period in 2011. The increase was primarily due to higher volumes and lower operating costs resulting from fewer planned outage days and lower lease expense. Provisions in the Bruce B lease agreement with Ontario Power Generation provide for a reduction in the annual lease expense if the annual average Ontario spot price for electricity is less than $30 per MWh which was the case in 2012.

U.S. Power's comparable EBITDA in fourth quarter 2012 was US$48 million compared to US$32 million in fourth quarter 2011. The increase was primarily due to higher generation volumes and higher realized power and capacity prices in New York, partially offset by lower earnings from the U.S. hydro facilities due to reduced water flows, as well as lower capacity prices and higher load serving costs in New England.

Natural Gas Storage's comparable EBITDA in fourth quarter 2012 was $20 million and was comparable to the same period in 2011.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay.
Canadian Restructuring Proposal	Canadian Mainline business and services restructuring proposal and 2012 and 2013 Mainline final tolls application
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time.
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines.
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it.
fracking	Hydraulic fracturing. A method of extracting natural gas from shale rock.
GHG	Greenhouse gas
HSE	Health, safety and environment
LNG	Liquefied natural gas
MET	Mitigation exemption tests
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
ASU	Accounting Standards Updatepension
DRP	Dividend reinvestment plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
U.S. GAAP	U.S. generally accepted accounting principles

Government and regulatory bodies

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
ISO	Independent System Operator
LMCI	Land Matters Consultation Initiative (Canada)
NDEQ	Nebraska Department of Environmental Quality (U.S.)
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission

Report of management

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada PipeLines Limited (TCPL or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and include amounts that are based on estimates and judgements. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2012 to that in 2011, and highlights significant changes between 2011 and 2010. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

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

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting are effective as of December 31, 2012, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

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

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

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

Russell K. Girling President and Chief Executive Officer	**Donald R. Marchand** Executive Vice-President and Chief Financial Officer

February 11, 2013

Independent Auditors' Report of Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA PIPELINES LIMITED

We have audited the accompanying consolidated financial statements of TransCanada PipeLines Limited, which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of income, comprehensive income, accumulated other comprehensive loss, equity and cash flows for each of the years in the three-year period ended December 31, 2012, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

AUDITORS' RESPONSIBILITY

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

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

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

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada PipeLines Limited as at December 31, 2012 and December 31, 2011, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2012 in accordance with US generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 11, 2013

Consolidated statement of income

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Revenues			
Natural Gas Pipelines	**4,264**	4,244	4,122
Oil Pipelines	**1,039**	827	–
Energy	**2,704**	2,768	2,730
	8,007	7,839	6,852
Income from Equity Investments (Note 9)	**257**	415	453
Operating and Other Expenses			
Plant operating costs and other	**2,577**	2,358	2,069
Commodity purchases resold	**1,049**	991	1,178
Property taxes	**434**	410	365
Depreciation and amortization	**1,375**	1,328	1,160
Valuation provision for MGP (Note 10)	**–**	–	146
	5,435	5,087	4,918
Financial Charges/(Income)			
Interest expense (Note 14)	**997**	1,044	754
Interest income and other	**(85)**	(55)	(94)
	912	989	660
Income before Income Taxes	**1,917**	2,178	1,727
Income Tax Expense/(Recovery) (Note 15)			
Current	**185**	194	(140)
Deferred	**276**	352	512
	461	546	372
Net Income	**1,456**	1,632	1,355
Net Income Attributable to Non-Controlling Interests (Note 17)	**96**	107	93
Net Income Attributable to Controlling Interests	**1,360**	1,525	1,262
Preferred Share Dividends (Note 19)	**22**	22	22
Net Income Attributable to Common Shares	**1,338**	1,503	1,240

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

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Net Income	**1,456**	1,632	1,355
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on investments in foreign operations[1]	**(129)**	137	(223)
Change in fair value of net investment hedges[2]	**44**	(73)	89
Change in fair value of cash flow hedges[3]	**48**	(212)	(169)
Reclassification to Net Income of gains and losses on cash flow hedges[4]	**138**	147	53
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[5]	**(73)**	(89)	(12)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[6]	**22**	10	5
Other Comprehensive Loss on equity investments[7]	**(70)**	(91)	(151)
Other Comprehensive Loss	**(20)**	(171)	(408)
Comprehensive Income	**1,436**	1,461	947
Comprehensive Income Attributable to Non-Controlling Interests	**75**	142	56
Comprehensive Income Attributable to Controlling Interests	**1,361**	1,319	891
Preferred Share Dividends	**22**	22	22
Comprehensive Income Attributable to Common Shares	**1,339**	1,297	869

1 Net of income tax expense of $32 million in 2012 (2011 – $29 million recovery; 2010 – $65 million expense).

2 Net of income tax expense of $15 million in 2012 (2011 – $28 million recovery; 2010 – $37 million expense).

3 Net of income tax expense of $13 million in 2012 (2011 – $106 million recovery; 2010 – $82 million recovery).

4 Net of income tax expense of $81 million in 2012 (2011 – $77 million expense; 2010 – $28 million expense).

5 Net of income tax recovery of $31 million in 2012 (2011 – $30 million recovery; 2010 – $7 million recovery).

6 Net of income tax expense of nil in 2012 (2011 – $3 million expense; 2010 – $3 million expense).

7 Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on cash flow hedges, offset by change in gains and losses on cash flow hedges, net of income tax recovery of $23 million in 2012 (2011 – $3 million recovery; 2010 – $69 million recovery).

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

Consolidated statement of cash flows

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Cash Generated from Operations			
Net income	**1,456**	1,632	1,355
Depreciation and amortization	**1,375**	1,328	1,160
Deferred income taxes (Note 15)	**276**	352	512
Income from equity investments (Note 9)	**(257)**	(415)	(453)
Distributed earnings received from equity investments (Note 9)	**376**	393	446
Employee post-retirement benefits funding lower than/(in excess of) expense (Note 20)	**9**	(2)	(50)
Valuation provision for MGP (Note 10)	**–**	–	146
Other	**24**	72	(7)
Decrease/(increase) in operating working capital (Note 22)	**287**	207	(292)
Net cash provided by operations	**3,546**	3,567	2,817
Investing Activities			
Capital expenditures (Note 4)	**(2,595)**	(2,513)	(4,376)
Equity investments	**(652)**	(633)	(597)
Acquisitions, net of cash acquired (Note 23)	**(214)**	–	–
Deferred amounts and other	**205**	92	(323)
Net cash used in investing activities	**(3,256)**	(3,054)	(5,296)
Financing Activities			
Dividends on common and preferred shares (Notes 18 and 19)	**(1,248)**	(1,185)	(1,109)
Distributions paid to non-controlling interests	**(113)**	(109)	(90)
Advances (to)/from parent, net	**(235)**	(2,090)	116
Notes payable issued/(repaid), net	**449**	(224)	472
Long-term debt issued, net of issue costs	**1,491**	1,622	2,371
Repayment of long-term debt	**(980)**	(1,272)	(494)
Common shares issued, net of issue costs	**269**	2,401	987
Partnership units issued, net of issue costs (Note 23)	**–**	321	–
Net cash (used in)/provided by financing activities	**(367)**	(536)	2,253
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(15)**	4	(7)
Decrease in Cash and Cash Equivalents	**(92)**	(19)	(233)
Cash and Cash Equivalents			
Beginning of year	**629**	648	881
Cash and Cash Equivalents			
End of year	**537**	629	648

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

Consolidated balance sheet

at December 31 (millions of Canadian dollars)	2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	**537**	629
Accounts receivable	**1,089**	1,113
Due from TransCanada Corporation (Note 25)	**985**	750
Inventories	**224**	248
Other (Note 5)	**992**	1,104
	3,827	3,844
Plant, Property and Equipment (Note 6)	**33,713**	32,467
Equity Investments (Note 9)	**5,366**	5,077
Goodwill (Note 7)	**3,458**	3,534
Regulatory Assets (Note 8)	**1,629**	1,684
Intangible and Other Assets (Note 10)	**1,342**	1,460
	49,335	48,066
LIABILITIES		
Current Liabilities		
Notes payable (Note 11)	**2,275**	1,863
Accounts payable and other (Note 12)	**2,340**	2,336
Accrued interest	**370**	367
Current portion of long-term debt (Note 14)	**894**	935
	5,879	5,501
Regulatory Liabilities (Note 8)	**268**	297
Other Long-Term Liabilities (Note 13)	**882**	929
Deferred Income Tax Liabilities (Note 15)	**3,953**	3,591
Long-Term Debt (Note 14)	**18,019**	17,724
Junior Subordinated Notes (Note 16)	**994**	1,016
	29,995	29,058
EQUITY		
Common shares, no par value (Note 18)	**14,306**	14,037
Issued and outstanding: December 31, 2012 – 738 million shares		
December 31, 2011 – 732 million shares		
Preferred shares (Note 19)	**389**	389
Additional paid-in capital	**400**	394
Retained earnings	**4,657**	4,561
Accumulated other comprehensive loss	**(1,448)**	(1,449)
Controlling interests	**18,304**	17,932
Non-controlling interests (Note 17)	**1,036**	1,076
	19,340	19,008
	49,335	48,066

Commitments, Contingencies and Guarantees (Note 24)

Subsequent Event (Note 26)

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

On behalf of the Board:

Russell K. Girling
Director

Kevin E. Benson
Director

Consolidated statement of accumulated other comprehensive loss

(millions of Canadian dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Pension and Other Post-retirement Plan Adjustments	Total
Balance at January 1, 2010	(592)	(40)	(240)	(872)
Foreign currency translation gains and losses on investments in foreign operations[1]	(180)	–	–	(180)
Change in fair value of net investment hedges[2]	89	–	–	89
Change in fair value of cash flow hedges[3]	–	(165)	–	(165)
Reclassification to Net Income of gains and losses on cash flow hedges[4, 5]	–	43	–	43
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[6]	–	–	(12)	(12)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[7]	–	–	5	5
Other Comprehensive Loss on equity investments[8]	–	(32)	(119)	(151)
Balance at December 31, 2010	(683)	(194)	(366)	(1,243)
Foreign currency translation gains and losses on investments in foreign operations[1]	113	–	–	113
Change in fair value of net investment hedges[2]	(73)	–	–	(73)
Change in fair value of cash flow hedges[3]	–	(213)	–	(213)
Reclassification to Net Income of gains and losses on cash flow hedges[4, 5]	–	137	–	137
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[6]	–	–	(89)	(89)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[7]	–	–	10	10
Other Comprehensive Loss on equity investments[8]	–	(11)	(80)	(91)
Balance at December 31, 2011	**(643)**	**(281)**	**(525)**	**(1,449)**
Foreign currency translation gains and losses on investments in foreign operations[1]	**(108)**	**–**	**–**	**(108)**
Change in fair value of net investment hedges[2]	**44**	**–**	**–**	**44**
Change in fair value of cash flow hedges[3]	**–**	**48**	**–**	**48**
Reclassification to Net Income of gains and losses on cash flow hedges[4, 5]	**–**	**138**	**–**	**138**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[6]	**–**	**–**	**(73)**	**(73)**
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[7]	**–**	**–**	**22**	**22**
Other Comprehensive Loss on equity investments[8]	**–**	**(15)**	**(55)**	**(70)**
Balance at December 31, 2012	**(707)**	**(110)**	**(631)**	**(1,448)**

1 Net of income tax expense of $32 million and non-controlling interest losses of $21 million in 2012 (2011 – $29 million recovery, $24 million gain; 2010 – $65 million expense, $43 million loss).

2 Net of income tax expense of $15 million in 2012 (2011 – $28 million recovery; 2010 – $37 million expense).

3 Net of income tax expense of $13 million and non-controlling interest gains of nil in 2012 (2011 – $106 million recovery, $1 million gain; 2010 – $82 million recovery, $4 million loss).

4 Net of income tax expense of $81 million and non-controlling interest gains of nil in 2012 (2011 – $77 million expense, $10 million gain; 2010 – $28 million expense, $10 million gain).

5 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 $41 million ($24 million, net of tax). 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.

6 Net of income tax recovery of $31 million in 2012 (2011 – $30 million recovery; 2010 – $7 million recovery).

7 Net of income tax expense of nil in 2012 (2011 – $3 million expense; 2010 – $3 million expense).

8 Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on cash flow hedges, offset by change in gains and losses on cash flow hedges, net of income tax recovery of $23 million in 2012 (2011 – $3 million recovery; 2010 – $69 million recovery).

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

Consolidated statement of equity

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Common Shares			
Balance at beginning of year	**14,037**	11,636	10,649
Proceeds from shares issued (Note 18)	**269**	2,401	987
Balance at end of year	**14,306**	14,037	11,636
Preferred Shares			
Balance at beginning and end of year	**389**	389	389
Additional Paid-In Capital			
Balance at beginning of year	**394**	359	353
Other	**6**	5	6
Dilution gain from TC PipeLines, LP units issued (Note 23)	**–**	30	–
Balance at end of year	**400**	394	359
Retained Earnings			
Balance at beginning of year	**4,561**	4,236	4,103
Net income attributable to controlling interests	**1,360**	1,525	1,262
Common share dividends	**(1,242)**	(1,178)	(1,107)
Preferred share dividends	**(22)**	(22)	(22)
Balance at end of year	**4,657**	4,561	4,236
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,449)**	(1,243)	(872)
Other comprehensive income/(loss)	**1**	(206)	(371)
Balance at end of year	**(1,448)**	(1,449)	(1,243)
Equity Attributable to Controlling Interests	**18,304**	17,932	15,377
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,076**	768	785
Net income attributable to non-controlling interests			
TC PipeLines, LP	**91**	101	87
Portland	**5**	6	6
Other comprehensive (loss)/income attributable to non-controlling interests	**(21)**	35	(37)
Sale of TC PipeLines, LP units			
Proceeds, net of issue costs	**–**	321	–
Decrease in TCPL's ownership	**–**	(50)	–
Distributions declared to non-controlling interests	**(113)**	(109)	(90)
Foreign exchange and other	**(2)**	4	17
Balance at end of year	**1,036**	1,076	768
Total Equity	**19,340**	19,008	16,145

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

Notes to consolidated financial statements

1. DESCRIPTION OF TCPL'S BUSINESS

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

Natural Gas Pipelines

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

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta and northeastern British Columbia (B.C.) (Alberta System);
- a natural gas transmission system extending from producing fields primarily located in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets primarily located in Wisconsin, Michigan, Illinois, Ohio and Indiana, and includes regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale); and
- a natural gas transmission system in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco (Guadalajara).

Through its Natural Gas Pipelines segment, TCPL operates and has ownership interests in natural gas pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border (GTN);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the Powder River Basin in Wyoming to Northern Border in North Dakota (Bison);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec, to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec and to the Portland system (TQM); and
- a 33.3 per cent controlling interest in TC PipeLines, LP, which has the following ownership interests in pipelines operated by TCPL:
  - a 46.4 per cent interest in Great Lakes, in which TCPL has a combined 69 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TCPL has a 16.7 per cent effective ownership interest through TC PipeLines, LP;
  - a 25 per cent interest in GTN, in which TCPL has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;

- a 25 per cent interest in Bison, in which TCPL has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
- a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California at the Mexico/California border (North Baja), in which TCPL has a 33.3 per cent effective ownership interest through TC PipeLines, LP; and
- a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon, to Wadsworth, Nevada (Tuscarora), in which TCPL has a 33.3 per cent effective ownership interest through TC PipeLines, LP.

TCPL does not operate but has ownership interests in natural gas pipelines and natural gas marketing activities as follows:

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

TCPL is currently constructing natural gas pipeline systems as follows:

- an extension to the Tamazunchale pipeline, extending the natural gas transmission system from Tamazunchale, San Luis Potosi to El Sauz, Queretaro;
- a natural gas transmission system that will transport natural gas from Chihuahua to Topolobampo, Mexico (Topolobampo); and
- a natural gas transmission system that will transport natural gas from El Oro to Mazatlan, Mexico (Mazatlan).

TCPL is currently developing the following natural gas pipeline systems:

- the proposed Coastal GasLink project consists of a natural gas transmission system that will transport natural gas from the Montney gas-producing region near Dawson Creek, B.C. to a liquefied natural gas export facility near Kitimat, B.C.; and
- the proposed Prince Rupert Gas Transmission Project consists of a pipeline to deliver natural gas from the Fort St. John area of B.C. to the proposed Pacific Northwest LNG facility at Port Edward near Prince Rupert, B.C.

Oil Pipelines

The Oil Pipelines segment consists of a wholly owned and operated crude oil pipeline system which connects Alberta crude oil supplies to U.S. refining markets in Illinois and Oklahoma (Keystone Pipeline System).

TCPL is currently constructing oil pipeline infrastructure as follows:

- a crude oil pipeline to connect the crude oil hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market (Gulf Coast Project);
- the Cushing Marketlink receipt facilities that will transport crude oil supply from the Permian Basin in western Texas to the U.S. Gulf Coast on facilities that form part of the Gulf Coast Project; and
- a crude oil terminal to be located at Hardisty, Alberta (Keystone Hardisty Terminal) that will provide Western Canadian producers with new batch accumulation tankage and pipeline infrastructure and access to the Keystone Pipeline System.

TCPL is currently developing oil pipeline infrastructure as follows:

- a new 1,897 km (1,179 mile) crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska (Keystone XL), subject to regulatory approval;
- the Bakken Marketlink project that will transport crude oil supply from the Williston Basin in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL;

- the proposed Northern Courier Pipeline, a 90 km (54 mile) pipeline system to service the Fort Hills mine site and transport bitumen and diluent between the Fort Hills mine site and the proposed Voyageur Upgrader, north of Fort McMurray, Alberta. The Company has been selected by the Fort Hills Energy Limited Partnership to design, build, own and operate the proposed pipeline; and
- the Grand Rapids Pipeline in northern Alberta, which includes both crude oil and diluent lines to transport volumes approximately 500 km (300 mile) between the producing area northwest of Fort McMurray and the Edmonton/Heartland region. The Company has entered into a joint venture agreement with Phoenix Energy Holdings Limited to develop the pipeline.

Energy

The Energy segment primarily consists of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- a natural gas-fired, combined-cycle power plant in Halton Hills, Ontario (Halton Hills);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired peaking facility located near Phoenix, Arizona (Coolidge);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine (Kibby Wind);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a waste-heat fuelled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas storage facility near Edson, Alberta (Edson); and
- an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TCPL does not operate but has ownership interests in power generation plants as follows:

- a 48.9 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau, Carleton, Montagne-Sèche and Gros-Morne wind farms in Gaspé, Québec (Cartier Wind); and
- a 50 per cent interest in a natural gas-fired, combined-cycle plant in Toronto, Ontario (Portlands Energy).

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

- a 100 per cent interest in the Sheerness power facility near Hanna, Alberta, which has 756 megawatts (MW) of generating capacity;
- a 100 per cent interest in the Sundance A power facilities near Wabamun, Alberta, which has 560 MW of generating capacity; and
- a 50 per cent interest in ASTC Power Partnership, which has a PPA in place for 706 MW of generating capacity from the Sundance B power facilities near Wabamun, Alberta.

TCPL is currently constructing a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in Greater Napanee, Ontario.

TCPL also has agreed to purchase nine Ontario solar projects in 2013 and 2014 with a combined capacity of 86 MW.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise indicated. Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook, have been adjusted as necessary to be compliant with the Company's policies under U.S. GAAP. The amounts adjusted at December 31, 2011 and December 31, 2010 in these consolidated financial statements are the same as those reported in Note 25 of TCPL's 2011 audited Consolidated Financial Statements included in TCPL's 2011 Annual Report.

Basis of Presentation

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

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 consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Regulation

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

Revenue Recognition

Natural Gas and Oil Pipelines

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

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

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

Energy

Power

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

Natural Gas Storage

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

Cash and Cash Equivalents

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

Inventories

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

Plant, Property and Equipment

Natural Gas Pipelines

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

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

Oil Pipelines

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

Energy

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

Corporate

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

Impairment of Long-Lived Assets

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

Acquisitions and Goodwill

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

Power Purchase Arrangements

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

Income Taxes

The Company uses the liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

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

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

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

Environmental Liabilities

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

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

Other Compensation Programs

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

Employee Post-Retirement Benefits

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

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Balance Sheet and recognizes changes in that funded status through Other Comprehensive Income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive Loss (AOCI) over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

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

Foreign Currency Transactions and Translation

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

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

Derivative Instruments and Hedging Activities

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

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

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

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

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

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

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

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

Long-Term Debt Transaction Costs

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

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Other Long-Term Liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2012

Fair Value Measurement

Effective January 1, 2012, the Company adopted the Accounting Standards Update (ASU) on fair value measurements as issued by the Financial Accounting Standards Board (FASB). Adoption of this ASU has resulted in an increase in the qualitative and quantitative disclosures regarding Level III measurements which have been included in Note 21.

Intangibles – Goodwill

Effective January 1, 2012, the Company adopted the ASU on testing goodwill for impairment as issued by the FASB. Adoption of this ASU has resulted in a change in the accounting policy related to testing goodwill for impairment, as the Company is now permitted to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount as a basis for determining whether it is required to proceed to the two-step quantitative impairment test. The adoption of this standard had no impact on reported values of goodwill.

Future Accounting Changes

Balance Sheet Offsetting/Netting

In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are offset in accordance with current U.S. GAAP. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosure regarding financial instruments which are subject to offsetting as described in this amendment.

4. SEGMENTED INFORMATION

year ended December 31, 2012 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,264**	**1,039**	**2,704**	**–**	**8,007**
Income from equity investments	**157**	**–**	**100**	**–**	**257**
Plant operating costs and other	**(1,365)**	**(296)**	**(819)**	**(97)**	**(2,577)**
Commodity purchases resold	**–**	**–**	**(1,049)**	**–**	**(1,049)**
Property taxes	**(315)**	**(45)**	**(74)**	**–**	**(434)**
Depreciation and amortization	**(933)**	**(145)**	**(283)**	**(14)**	**(1,375)**
	1,808	**553**	**579**	**(111)**	**2,829**
Interest expense					**(997)**
Interest income and other					**85**
Income before income taxes					**1,917**
Income tax expense					**(461)**
Net Income					**1,456**
Net Income Attributable to Non-Controlling Interests					**(96)**
Net Income Attributable to Controlling Interests					**1,360**
Preferred Share Dividends					**(22)**
Net Income Attributable to Common Shares					**1,338**

year ended December 31, 2011 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines[1]**	**Energy**	**Corporate**	**Total**
Revenues	4,244	827	2,768	–	7,839
Income from equity investments	159	–	256	–	415
Plant operating costs and other	(1,221)	(209)	(842)	(86)	(2,358)
Commodity purchases resold	–	–	(991)	–	(991)
Property taxes	(307)	(31)	(72)	–	(410)
Depreciation and amortization	(923)	(130)	(261)	(14)	(1,328)
	1,952	457	858	(100)	3,167
Interest expense					(1,044)
Interest income and other					55
Income before income taxes					2,178
Income tax expense					(546)
Net Income					1,632
Net Income Attributable to Non-Controlling Interests					(107)
Net Income Attributable to Controlling Interests					1,525
Preferred Share Dividends					(22)
Net Income Attributable to Common Shares					1,503

1 Commencing in February 2011, TCPL began recording earnings for the Keystone Pipeline System.

year ended December 31, 2010 (millions of Canadian dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,122	–	2,730	–	6,852
Income from equity investments	153	–	300	–	453
Plant operating costs and other	(1,165)	–	(805)	(99)	(2,069)
Commodity purchases resold	–	–	(1,178)	–	(1,178)
Property taxes	(294)	–	(71)	–	(365)
Depreciation and amortization	(913)	–	(247)	–	(1,160)
Valuation provision	(146)	–	–	–	(146)
	1,757	–	729	(99)	2,387
Interest expense					(754)
Interest income and other					94
Income before income taxes					1,727
Income tax expense					(372)
Net Income					1,355
Net Income Attributable to Non-Controlling Interests					(93)
Net Income Attributable to Controlling Interests					1,262
Preferred Share Dividends					(22)
Net Income Attributable to Common Shares					1,240

Total Assets

at December 31 (millions of Canadian dollars)	2012	2011
Natural Gas Pipelines	**23,210**	23,161
Oil Pipelines	**10,485**	9,440
Energy	**13,157**	13,269
Corporate	**2,483**	2,196
	49,335	48,066

Geographic Information

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Revenues[1]			
Canada – domestic	**3,527**	3,929	3,178
Canada – export	**1,121**	1,087	838
United States	**3,252**	2,752	2,796
Mexico	**107**	71	40
	8,007	7,839	6,852

1 Revenues are attributed based on the country in which the product or service originated.

at December 31 (millions of Canadian dollars)	2012	2011
Plant, Property and Equipment		
Canada	**18,054**	17,552
United States	**14,904**	14,388
Mexico	**755**	527
	33,713	32,467

Capital Expenditures

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Natural Gas Pipelines	**1,389**	917	1,192
Oil Pipelines	**1,145**	1,204	2,696
Energy	**24**	384	473
Corporate	**37**	8	15
	2,595	2,513	4,376

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian dollars)	2012	2011
Fair value of derivative contracts (Note 21)	**259**	361
Deferred income tax assets (Note 15)	**285**	239
Regulatory assets (Note 8)	**178**	178
Other	**270**	326
	992	1,104

6. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian dollars)	2012 Cost	2012 Accumulated Depreciation	2012 Net Book Value	2011 Cost	2011 Accumulated Depreciation	2011 Net Book Value
Natural Gas Pipelines[1]						
Canadian Mainline						
Pipeline	**8,801**	**5,192**	**3,609**	8,785	4,958	3,827
Compression	**3,370**	**1,880**	**1,490**	3,362	1,765	1,597
Metering and other	**391**	**182**	**209**	383	175	208
	12,562	**7,254**	**5,308**	12,530	6,898	5,632
Under construction	**163**	**–**	**163**	28	–	28
	12,725	**7,254**	**5,471**	12,558	6,898	5,660
Alberta System						
Pipeline	**7,214**	**3,221**	**3,993**	6,701	3,062	3,639
Compression	**1,885**	**1,177**	**708**	1,778	1,109	669
Metering and other	**958**	**420**	**538**	931	409	522
	10,057	**4,818**	**5,239**	9,410	4,580	4,830
Under construction	**463**	**–**	**463**	368	–	368
	10,520	**4,818**	**5,702**	9,778	4,580	5,198
ANR						
Pipeline	**864**	**49**	**815**	858	47	811
Compression	**514**	**72**	**442**	510	72	438
Metering and other	**520**	**81**	**439**	524	59	465
	1,898	**202**	**1,696**	1,892	178	1,714
Under construction	**63**	**–**	**63**	20	–	20
	1,961	**202**	**1,759**	1,912	178	1,734
Other Natural Gas Pipelines						
GTN	**1,565**	**411**	**1,154**	1,589	370	1,219
Great Lakes	**1,544**	**750**	**794**	1,577	741	836
Foothills	**1,634**	**1,062**	**572**	1,630	1,005	625
Mexico	**536**	**59**	**477**	547	39	508
Other[2]	**1,548**	**226**	**1,322**	1,576	187	1,389
	6,827	**2,508**	**4,319**	6,919	2,342	4,577
Under construction	**297**	**–**	**297**	33	–	33
	7,124	**2,508**	**4,616**	6,952	2,342	4,610
	32,330	**14,782**	**17,548**	31,200	13,998	17,202
Oil Pipelines						
Keystone						
Pipeline	**4,897**	**177**	**4,720**	4,904	80	4,824
Pumping equipment	**1,560**	**75**	**1,485**	1,502	38	1,464
Tanks and other	**372**	**23**	**349**	548	15	533
	6,829	**275**	**6,554**	6,954	133	6,821
Under construction[3]	**3,678**	**–**	**3,678**	2,433	–	2,433
	10,507	**275**	**10,232**	9,387	133	9,254
Energy						
Natural Gas – Ravenswood	**1,799**	**290**	**1,509**	1,799	220	1,579
Natural Gas – Other[4]	**2,975**	**746**	**2,229**	3,002	665	2,337
Hydro	**634**	**106**	**528**	620	90	530
Wind[5]	**907**	**118**	**789**	843	88	755
Natural Gas Storage[6]	**677**	**83**	**594**	454	78	376
Other	**134**	**86**	**48**	131	83	48
	7,126	**1,429**	**5,697**	6,849	1,224	5,625
Under construction – Other	**136**	**–**	**136**	308	–	308
	7,262	**1,429**	**5,833**	7,157	1,224	5,933
Corporate	**154**	**54**	**100**	129	51	78
	50,253	**16,540**	**33,713**	47,873	15,406	32,467

1 In 2012, the Company capitalized $32 million (2011 – $23 million) relating to the equity portion of AFUDC for natural gas pipelines with a corresponding amount recorded in Interest Income and Other.

2 Includes in service assets of Bison, Portland, North Baja, Tuscarora and Ventures LP. Bison went in service in January 2011.

3 Includes $2.0 billion and $1.5 billion for Keystone XL and the Gulf Coast Project, respectively, at December 31, 2012 (2011 – $1.5 billion and $0.9 billion, respectively). Keystone XL remains subject to regulatory approvals.

4 Includes facilities with long-term PPAs that are accounted for as operating leases, including Coolidge which went in service in May 2011. The cost and accumulated depreciation of these facilities were $601 million and $55 million, respectively, at December 31, 2012 (2011 – $605 million and $34 million, respectively). Revenues of $73 million were recognized in 2012 (2011 – $53 million; 2010 – $15 million) through the sale of electricity under the related PPAs.

5 Includes Cartier phase two of Gros-Morne effective November 2012, phase one of Gros-Morne effective November 2011, and Montagne-Sèche effective November 2011.

6 Includes acquisition in December 2012 of BP's 40 per cent interest in the assets of the Crossfield Gas Storage facility and BP's interest in CrossAlta Gas Storage & Services Ltd.

7. GOODWILL

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

(millions of Canadian dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2011	2,634	823	3,457
Foreign exchange rate changes	59	18	77
Balance at December 31, 2011	2,693	841	3,534
Foreign exchange rate changes	**(58)**	**(18)**	**(76)**
Balance at December 31, 2012	**2,635**	**823**	**3,458**

8. RATE-REGULATED BUSINESSES

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

Canadian Regulated Operations

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

TCPL's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

In 2011, TCPL filed a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline, including addressing tolls for 2012 and 2013. The application included a 7.0 per cent after-tax weighted average cost of capital (ATWACC) fair return which is equivalent to an ROE of 12 per cent on a deemed common equity of 40 per cent. This application is currently under review by the

NEB with a decision not expected before late first quarter 2013 and, accordingly, any adjustments relating to 2012 results will be recorded when the decision is received. In the absence of a decision by the NEB, Canadian Mainline's 2012 results reflect the last approved ROE of 8.08 per cent on a deemed common equity of 40 per cent and exclude incentive earnings.

The Canadian Mainline operated under a five-year settlement, effective from January 1, 2007 to December 31, 2011. The Canadian Mainline's cost of capital for establishing tolls under the settlement reflected an ROE as determined by the NEB's RH-2-94 ROE formula on a deemed common equity of 40 per cent. The allowed ROE in 2011 for the Canadian Mainline was 8.08 per cent. The balance of the capital structure was comprised of short and long-term debt.

The settlement also established the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. Variances in OM&A costs were shared equally between TCPL and its customers in 2011. All other cost elements of the revenue requirement were treated on a flow-through basis. The settlement also allowed for performance-based incentive arrangements.

In September 2011, the NEB approved the Canadian Mainline's interim tolls as final for 2011, including TCPL's proposal to carry forward any revenue variances into the determination of 2012 tolls. However, the NEB determined that TCPL's inclusion of certain elements in the proposed 2011 revenue requirement, which were derived in accordance with the 2007 - 2011 Settlement, would be examined with TCPL's 2012-2013 Tolls Application before a final decision was rendered on the 2011 revenue requirement. Any adjustments relating to the 2011 revenue requirement will be recorded when the NEB decision is received.

Alberta System

In September 2010, the NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application. The settlement provided for a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixed certain annual OM&A costs during the term. Any variances between actual costs and those agreed to in the settlement accrued to TCPL. All other costs were treated on a flow-through basis.

Foothills

In June 2010, TCPL reached an agreement to establish a cost of capital for Foothills that reflected a 9.70 per cent ROE on a deemed common equity of 40 per cent for 2010 to 2012. A component of OM&A was fixed, subject to the terms of the B.C. System/Foothills Integration Settlement, and variances between actual and fixed amounts were shared with customers up to and including June 2011 when the OM&A savings cap was reached.

TQM

In November 2010, the NEB approved TQM's multi-year settlement with its interested parties regarding its annual revenue requirements for 2010 to 2012. As part of the settlement, the annual revenue requirement was comprised of fixed and flow-through components. The fixed component included certain OM&A costs, return on rate base, depreciation and municipal taxes. Any variances between actual costs and those included in the fixed component accrued to TQM.

U.S. Regulated Operations

TCPL's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is another FERC regulated entity that owns and operates storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC in August 2012. ANR Storage Company is required to file a NGA Section 4 general rate case no later than July 1, 2016.

In 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under FERC regulation. The requests were granted and TC Offshore LLC began operating under FERC approved tariff rates on November 1, 2012. TC Offshore LLC is required to file a cost and revenue study to justify its existing approved cost-based rates after its first three years of operation.

GTN

GTN is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. That settlement provided for a four year moratorium during which GTN and the settling parties are prohibited from taking certain actions under the NGA, including filings to adjust rates. GTN is required to file for new rates to be effective January 1, 2016.

Great Lakes

Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes rates were established pursuant to a settlement approved by the FERC in July 2010. Great Lakes is required to file a NGA Section 4 general rate case no later than November 1, 2013.

Bison

Bison is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. Bison is permitted to discount or negotiate these rates on a non-discriminatory basis. Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian dollars)	**2012**	**2011**	**Remaining Recovery/ Settlement Period (years)**
Regulatory Assets			
Deferred income taxes[1]	**1,122**	1,178	n/a
Operating and debt-service regulatory assets[2]	**171**	172	1
Adjustment account[3]	**80**	82	30
Other[4]	**434**	430	n/a
	1,807	1,862	
Less: Current portion included in Other Current Assets	**178**	178	
	1,629	1,684	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**150**	184	1- 17
Operating and debt-service regulatory liabilities[2]	**84**	135	1
Other[4]	**134**	117	n/a
	368	436	
Less: Current portion included in Accounts Payable	**100**	139	
	268	297	

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

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2012 would have been $50 million lower (2011 – $102 million higher) had these amounts not been recorded as regulatory assets and liabilities.

3 A regulatory adjustment account of $85 million was established and agreed upon by Canadian Mainline stakeholders to reduce tolls in 2010. Amortization of the adjustment account commenced in 2011 at the composite depreciation rate.

4 Pre-tax operating results in 2012 would have been $97 million higher (2011 – $106 million lower) had these amounts not been recorded as regulatory assets and liabilities.

5 Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, U.S. GAAP would have required the inclusion of these unrealized gains or losses in Net Income.

9. EQUITY INVESTMENTS

(millions of Canadian dollars)	Ownership Interest as at December 31, 2012	Income/(Loss) from Equity Investments year ended December 31 2012	2011	2010	Equity Investments at December 31 2012	2011
Natural Gas Pipelines						
Northern Border[1]		**72**	75	69	**511**	545
Iroquois	44.5%	**41**	40	40	**174**	181
TQM	50.0%	**16**	17	16	**80**	82
Other	Various	**28**	27	28	**60**	72
Energy						
Bruce A	48.9%	**(149)**	33	35	**4,033**	3,561
Bruce B	31.6%	**163**	77	138	**69**	115
ASTC Power Partnership	50.0%	**40**	84	41	**42**	58
Portlands Energy	50.0%	**28**	33	33	**341**	313
CrossAlta[2]		**10**	23	45	**n/a**	18
Other	Various	**8**	6	8	**56**	132
		257	415	453	**5,366**	5,077

1 The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2012, TCPL had an ownership interest in TC PipeLines, LP of 33.3 per cent (2011 – 33.3 per cent; 2010 – 38.2 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 16.7 per cent (2011 – 16.7 per cent; 2010 – 19.1 per cent).

2 In 2011, Property, Plant and Equipment included $63 million of assets owned directly by TCPL through an undivided interest in the Crossfield joint venture which were utilized in the operations of the CrossAlta joint venture. In December 2012, TCPL acquired the remaining 40 per cent interest in CrossAlta to bring the Company's ownership interest to 100 per cent. The results reflect the Company's 60 per cent share of equity income up to December 18, 2012. Refer to Note 23, Acquisitions and Dispositions, for additional information.

Distributions received from equity investments for the year ended December 31, 2012 were $436 million (2011 – $494 million; 2010 – $486 million) of which $60 million (2011 – $101 million; 2010 – $40 million) were returns of capital and are included in Deferred amounts and other in the Consolidated Statement of Cash Flows. The undistributed earnings from equity investments as at December 31, 2012 were $883 million (2011 – $1,062 million; 2010 – $1,141 million). At December 31, 2012, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company and Bruce Power is US$119 million (2011 – US$120 million) and $918 million (2011 – $820 million), respectively. This difference is primarily due to the fair value assessment of assets at the time of the acquisitions of Northern Border and Bruce Power, and interest capitalized related to the refurbishment of Units 1 and 2 at Bruce Power.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Income			
Revenues	**3,860**	4,042	3,920
Operating and other expenses	**(3,090)**	(2,989)	(2,773)
Net income	**717**	929	1,009
Net income attributable to TCPL	**257**	415	453

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Balance Sheet		
Current assets	**1,593**	1,430
Non current assets	**12,154**	11,550
Current liabilities	**(1,187)**	(1,172)
Non current liabilities	**(3,787)**	(3,232)

10. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian dollars)	**2012**	**2011**
PPAs[1]	**376**	428
Loans and advances[2]	**196**	224
Fair value of derivative contracts (Note 21)	**187**	202
Deferred income tax assets (Note 15)	**104**	126
Employee post-retirement benefits (Note 20)	**11**	–
Other	**468**	480
	1,342	1,460

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

	2012			**2011**		
at December 31 (millions of Canadian dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	**Cost**	**Accumulated Amortization**	**Net Book Value**
Sheerness	**585**	**273**	**312**	585	234	351
Sundance A	**225**	**161**	**64**	225	148	77
	810	**434**	**376**	810	382	428

Amortization expense for these PPAs was $52 million for the year ended December 31, 2012 (2011 and 2010 – $52 million). The expected annual amortization expense in each of the next five years is $52 million.

2 As at December 31, 2012, TCPL held a $236 million (2011 – $265 million) note receivable from the seller of Ravenswood which bears interest at 6.75 per cent and matures in 2040. The current portion of the note receivable of $40 million (2011 – $41 million) is included in Other Current Assets.

Sundance A

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by the PPA owner in January 2011. In July 2012, TCPL received the binding arbitration decision regarding the Sundance A PPA force majeure and economic destruction claims. The arbitration panel determined that the PPA should not be terminated and ordered TransAlta Corporation (TransAlta) to return Units 1 and 2 to service. The panel also limited TransAlta's force majeure claim from November 20, 2011 until the units can reasonably be returned to service. TransAlta announced that it expects the units to be returned to service in fall 2013.

Between December 2010 and March 2012, TCPL recorded revenues and costs related to the Sundance A PPA as though the outages of Units 1 and 2 were interruptions of supply. As a result of the decision, TCPL recorded a $50 million pre-tax charge in second quarter of 2012, comprised of $20 million previously accrued in 2011 and $30 million previously accrued through first quarter of 2012, as these amounts are no longer recoverable. Other than the $20 million charge related to 2011 and the amortization of the original PPA cost, there are no pre-tax earnings recognized in 2012 for the Sundance A PPA.

Advances to Aboriginal Pipeline Group

The Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TCPL have an agreement governing TCPL's role in the Mackenzie Gas Project (MGP). Under the agreement, TCPL agreed to finance the APG for its one-third share of project pre-development costs. Amounts advanced to the APG for the MGP in 2012 and 2011 have been expensed. In 2010, a valuation provision of $146 million was recorded on the loan to the APG due to uncertainty with the project's ultimate commercial structure, fiscal framework, timeframes under which the project would proceed and when the advances to the APG will be repaid.

11. NOTES PAYABLE

	2012		2011	
(millions of Canadian dollars)	**Outstanding December 31**	**Weighted Average Interest Rate per Annum at December 31**	**Outstanding December 31**	**Weighted Average Interest Rate per Annum at December 31**
Canadian dollars	**803**	**1.2%**	466	1.2%
U.S. dollars (2012 – US$1,480; 2011 – US$1,373)	**1,472**	**0.4%**	1,397	0.5%
	2,275		1,863	

Notes payable consists of commercial paper issued by TCPL and wholly owned subsidiaries, and drawings on line-of-credit and demand facilities.

At December 31, 2012, total committed revolving and demand credit facilities of $5.3 billion were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving, extendible TCPL credit facility, maturing October 2017. The facility was fully available at December 31, 2012. The cost to maintain the credit facility was $4 million in 2012 (2011 – $2 million; 2010 – $2 million);
- a US$300 million committed, syndicated, revolving TCPL USA credit facility, guaranteed by TransCanada and maturing February 2013. At December 31, 2012, this facility was fully available. This facility is part of the initial US$1.0 billion credit facility discussed in Note 14. The cost to maintain the credit facility was nil in 2012 (2011 – $1 million; 2010 – $1 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TC Keystone credit facility, guaranteed by TCPL and TCPL USA and maturing November 2013. The facility was fully available at December 31, 2012. The cost to maintain the credit facility was $1 million in 2012 (2011 – $4 million; 2010 – $5 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL and maturing October 2013. At December 31, 2012, this facility was fully available. The cost to maintain the credit facility was $1 million in 2012 (2011 – $4 million; 2010 – $4 million); and
- demand lines totalling $1 billion, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2012, the Company had used approximately $627 million of these demand lines for letters of credit.

12. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Trade payables	**923**	696
Fair value of derivative contracts (Note 21)	**283**	485
Dividends payable	**316**	301
Regulatory liabilities (Note 8)	**100**	139
Deferred income tax liabilities (Note 15)	**–**	81
Other	**718**	634
	2,340	2,336

13. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Employee post-retirement benefit (Note 20)	**482**	321
Fair value of derivative contracts (Note 21)	**186**	349
Guarantees (Note 24)	**17**	118
Asset retirement obligations	**72**	65
Other	**125**	76
	882	929

14. LONG-TERM DEBT

Outstanding loan amounts (millions of Canadian dollars)	Maturity Dates	2012 Outstanding December 31	2012 Interest Rate[1]	2011 Outstanding December 31	2011 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2014 to 2020	**874**	**10.9%**	874	10.9%
U.S. dollars (2012 – US$400; 2011 – US$600)	2021	**398**	**9.9%**	610	9.5%
Medium-Term Notes					
Canadian dollars	2013 to 2041	**4,549**	**5.9%**	4,549	5.9%
Senior Unsecured Notes					
U.S. dollars (2012 – US$10,126; 2011 – US$8,626)[2]	2013 to 2040	**10,057**	**5.6%**	8,759	6.2%
		15,878		14,792	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2014 to 2024	**382**	**11.5%**	387	11.5%
U.S. dollars (2012 – US$200; 2011 – US$375)	2023	**199**	**7.9%**	381	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. dollars (2012 and 2011 – US$33)	2026	**32**	**7.5%**	33	7.5%
		1,117		1,305	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2012 – nil; 2011 – US$500)		**–**	**–**	509	0.6%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2012 and 2011 – US$432)	2021 to 2025	**430**	**8.9%**	438	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2012 and 2011 – US$325)	2015 to 2035	**323**	**5.5%**	331	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2012 – US$312; 2011 – US$363)	2017	**310**	**1.5%**	369	1.6%
Senior Unsecured Notes					
U.S. dollars (2012 and 2011 – US$350)	2021	**348**	**4.7%**	356	4.7%
		658		725	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2012 – US$354; 2011 – US$373)	2018 to 2030	**352**	**7.8%**	379	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2012 – US$27; 2011 – US$30)	2017	**27**	**4.0%**	31	4.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2012 – US$129; 2011 – US$147)	2018	**128**	**6.1%**	149	6.1%
		18,913		18,659	
Less: Current Portion of Long-Term Debt		**894**		935	
		18,019		17,724	

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

[2] Includes fair value adjustments of $10 million (2011 – $13 million) attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$350 million of debt at December 31, 2012 (2011 – US$350 million).

[3] Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2013 – $894 million; 2014 – $970 million; 2015 – $1,561 million; 2016 – $1,214 million; and 2017 – $555 million.

TransCanada PipeLines Limited

In August 2012, TCPL issued US$1.0 billion of Senior Notes maturing August 1, 2022 and bearing interest at 2.5 per cent.

In May 2012, TCPL retired US$200 million of 8.625 per cent Senior Notes.

In March 2012, TCPL issued US$500 million of Senior Notes maturing March 2, 2015, and bearing interest at 0.875 per cent.

In November 2011, TCPL issued $500 million and $250 million of Medium-Term Notes maturing November 15, 2021 and November 15, 2041, respectively, and bearing interest at 3.65 per cent and 4.55 per cent, respectively.

In May 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes.

In January 2011, TCPL retired $300 million of 4.3 per cent Medium-Term Notes.

In September 2010, TCPL issued US$1.0 billion of Senior Notes maturing October 1, 2020, and bearing interest at 3.80 per cent.

In June 2010, TCPL issued US$500 million and US$750 million of Senior Notes maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.4 per cent and 6.1 per cent, respectively.

In February 2010, TCPL retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, TCPL retired $130 million of 10.50 per cent debentures.

NOVA Gas Transmission Ltd.

In December 2012, NOVA Gas Transmission Ltd. (NGTL) retired US$175 million of 8.5 per cent Debentures.

Debentures issued by NGTL in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2012.

TransCanada PipeLine USA Ltd.

TCPL USA has an initial US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada which was reduced to a US$300 million credit facility through term loan repayments of US$500 million and US$200 million in January 2012 and August 2011, respectively. The facility consists of a US$300 million revolving facility maturing in February 2013, described further in Note 11. The term loan's outstanding balance of US$500 million at December 31, 2011 was fully repaid in January 2012.

TC PipeLines, LP

In July 2011, TC PipeLines, LP increased its senior syndicated revolving credit facility to US$500 million and extended the maturity date to July 2016. In November 2012, the Senior Credit facility was further amended, extending the maturity date to November 2017.

In December 2011, TC PipeLines, LP repaid a maturing US$300 million term loan with a draw under this facility, and at December 31, 2012, US$312 million (2011 – US$363 million) was outstanding on the facility.

In June 2011, TC PipeLines, LP issued US$350 million of 4.65 per cent Senior Notes due 2021. The proceeds from the issuance were used to partially repay TC PipeLines, LP's term loan and borrowings under its senior revolving credit facility, and repay its bridge loan facility described below.

In May 2011, TC PipeLines, LP made draws of US$61 million on a bridge loan facility and US$125 million on its senior revolving credit facility to partially fund the acquisition of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) as further described in Note 23.

Interest Expense

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Interest on long-term debt	**1,190**	1,154	1,149
Interest on junior subordinated notes	**63**	63	65
Interest on short-term debt	**37**	123	68
Capitalized interest	**(300)**	(302)	(587)
Amortization and other financial charges[1]	**7**	6	59
	997	1,044	754

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

The Company made interest payments of $1,027 million in 2012 (2011 – $1,069 million; 2010 – $718 million) on long-term debt and junior subordinated notes, net of interest capitalized on construction projects.

15. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Current			
Canada	**171**	196	29
Foreign	**14**	(2)	(169)
	185	194	(140)
Deferred			
Canada	**60**	126	161
Foreign	**216**	226	351
	276	352	512
Income Tax Expense	**461**	546	372

Geographic Components of Income

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Canada	**821**	1,069	758
Foreign	**1,096**	1,109	969
Income before Income Taxes	**1,917**	2,178	1,727

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Income before Income Taxes	**1,917**	2,178	1,727
Federal and provincial statutory tax rate	**25.0%**	26.5%	28.0%
Expected income tax expense	**479**	577	484
Income tax differential related to regulated operations	**41**	42	8
Higher/(lower) effective foreign tax rates	**1**	(5)	(36)
Income from equity investments and non-controlling interests	**(40)**	(45)	(40)
Other	**(20)**	(23)	(44)
Actual Income Tax Expense	**461**	546	372

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian dollars)	2012	2011
Deferred Income Tax Assets		
Operating loss carryforwards	**1,024**	900
Financial instruments	**88**	166
Pension and other post-employment benefits	**83**	42
Deferred amounts	**49**	49
Other	**86**	117
	1,330	1,274
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**3,804**	3,609
Equity investments	**578**	457
Taxes on future revenue requirement	**283**	295
Unrealized foreign exchange gains on long-term debt	**159**	133
Other	**70**	87
	4,894	4,581
Net Deferred Income Tax Liabilities	**3,564**	3,307

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

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Deferred Income Tax Assets		
Other current assets (Note 5)	**285**	239
Intangible and other assets (Note 10)	**104**	126
	389	365
Deferred Income Tax Liabilities		
Accounts payable and other (Note 12)	**–**	81
Deferred income taxes	**3,953**	3,591
	3,953	3,672
Net Deferred Income Tax Liabilities	**3,564**	3,307

At December 31, 2012, the Company has recognized the benefit of unused non-capital loss carryforwards of $865 million (2011 – $450 million) for federal and provincial purposes in Canada, which expire from 2014 to 2032.

At December 31, 2012, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,174 million (2011 – US$2,119 million) for federal purposes in the U.S., which expire from 2028 to 2032.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2012 by approximately $144 million (2011 – $136 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $175 million, net of refunds, were made in 2012 (2011 – refunds, net of payments made, of $85 million; 2010 – payments, net of refunds, of $57 million).

Reconciliation of Unrecognized Tax Benefit

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

at December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Unrecognized tax benefits at beginning of year	**48**	58	52
Gross increases – tax positions in prior years	**2**	9	7
Gross decreases – tax positions in prior years	**(6)**	(7)	(1)
Gross increases – tax positions in current year	**9**	11	8
Settlements	**–**	–	(7)
Lapses of statute of limitations	**(8)**	(23)	(1)
Unrecognized tax benefits at end of year	**45**	48	58

TCPL expects the enactment of certain Canadian federal tax legislation in the next 12 months which is expected to result in a favourable income tax adjustment of approximately $25 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TCPL does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

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

TCPL's practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Net tax expense for the year ended December 31, 2012 reflects a reversal of $2 million of interest expense and nil for penalties (2011 – $12 million reversal of interest expense and nil for penalties; 2010 – $3 million for interest expense and nil for penalties). At December 31, 2012, the Company had $5 million accrued for interest expense and nil accrued for penalties (December 31, 2011 – $7 million accrued for interest expense and nil accrued for penalties).

16. JUNIOR SUBORDINATED NOTES

		2012		2011	
Outstanding loan amount (millions of Canadian dollars)	**Maturity Date**	**Outstanding December 31**	**Effective Interest Rate**	**Outstanding December 31**	**Effective Interest Rate**
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2012 and 2011 – US$1,000)	2067	**994**	**6.5%**	1,016	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

17. NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Non-controlling interest in TC PipeLines, LP[1]	**953**	997
Non-controlling interest in Portland[2]	**83**	79
	1,036	1,076

The Company's non-controlling interests included in the Consolidated Statement of Income were as follows:

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Non-controlling interest in TC PipeLines, LP[1]	**91**	101	87
Non-controlling interest in Portland[2]	**5**	6	6
	96	107	93

1 Effective May 3, 2011, the non-controlling interest in TC PipeLines, LP increased from 61.8 per cent to 66.7 per cent due to the issuance of equity to non-controlling interests in TC PipeLines, LP associated with the sale of 25 per cent interests in GTN LLC and Bison LLC pipelines from TCPL to TC PipeLines, LP. The non-controlling interest in TC PipeLines, LP from January 1, 2010 to May 3, 2011 was 61.8 per cent.

2 The non-controlling interests in Portland as at December 31, 2012 represented the 38.3 per cent interest not owned by TCPL (2011 and 2010 – 38.3 per cent).

In 2012, TCPL received fees of $3 million from TC PipeLines, LP (2011 and 2010 – $2 million) and $7 million from Portland (2011 and 2010 – $7 million) for services provided.

18. COMMON SHARES

	Number of Shares	**Amount**
	(thousands)	(millions of Canadian dollars)
Outstanding at January 1, 2010	649,426	10,649
Issuance of common shares for cash	26,121	987
Outstanding at December 31, 2010	675,547	11,636
Issuance of common shares for cash	56,325	2,401
Outstanding at December 31, 2011	731,872	14,037
Issuance of common shares for cash	**6,509**	**269**
Outstanding at December 31, 2012	**738,381**	**14,306**

Common Shares Issued and Outstanding

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

Restriction on Dividends

Certain terms of the Company's preferred shares and debt investments could restrict the Company's ability to declare dividends on preferred and common shares. At December 31, 2012, approximately $1.0 billion (2011 – $2.7 billion; 2010 $3.6 billion) was available for the payment of dividends on common and preferred shares.

Cash Dividends
Cash dividends of $1.2 billion were paid in 2012 (2011 – $1.2 billion; 2010 – 1.1 billion).

19. PREFERRED SHARES

at December 31	Number of Shares Authorized and Outstanding	Dividend Rate per Share	Redemption Price per Share	2012	2011
	(thousands)			(millions of Canadian dollars)	(millions of Canadian dollars)
Cumulative First Preferred Shares					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

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

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

Dividend Reinvestment Plan
Under the Company's Dividend Reinvestment Plan (DRP), eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Commencing with the dividends declared in April 2011, dividends payable to shareholders who participate in the DRP are satisfied with common shares purchased on the open market determined on the basis of the weighted average purchase price of such common shares. Previously, common shares issued in lieu of cash dividends under the DRP were issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2010, and was reduced to two per cent commencing with the dividends declared in February 2011 and was eliminated completely in April 2011.

Cash Dividends
Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in each of 2012, 2011 and 2010.

20. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plans increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years (2011 – eight years; 2010 – eight years).

The Company also provides its employees with a Savings Plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2012 (2011 – 12 years; 2010 – 12 years). In 2012, the Company expensed $24 million (2011 – $23 million, 2010 – $21 million) for the Savings Plan and DC Plans.

Total cash payments for employee post-retirement benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $114 million in 2012 (2011 – $93 million, 2010 – $127 million), including $24 million in 2012 (2011- $23 million, 2010 – $21 million) related to the Savings Plan and DC Plans. In addition to these cash payments, in 2012 the Company provided a $48 million letter of credit to the Canadian DB Plan (2011 – $27 million), resulting in a total of $75 million provided to the Canadian DB Plan under letters of credit at December 31, 2012.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2013, and the next required valuation will be as at January 1, 2014.

at December 31 (millions of Canadian dollars)	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**1,836**	1,622	**170**	159
Service cost	**66**	54	**2**	2
Interest cost	**94**	91	**8**	9
Employee contributions	**4**	4	**1**	1
Benefits paid	**(79)**	(71)	**(9)**	(9)
Actuarial loss	**227**	131	**16**	7
Foreign exchange rate changes	**(6)**	5	**(2)**	1
Benefit obligation – end of year	**2,142**	1,836	**186**	170
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,656**	1,636	**29**	29
Actual return on plan assets	**165**	21	**4**	–
Employer contributions	**83**	62	**7**	8
Employee contributions	**4**	4	**1**	1
Benefits paid	**(79)**	(71)	**(9)**	(9)
Foreign exchange rate changes	**(4)**	4	**–**	–
Plan assets at fair value – end of year	**1,825**	1,656	**32**	29
Funded Status – Plan Deficit	**(317)**	(180)	**(154)**	(141)

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

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

at December 31 (millions of Canadian dollars)	Pension Benefit Plans 2012	Pension Benefit Plans 2011	Other Post-Retirement Benefit Plans 2012	Other Post-Retirement Benefit Plans 2011
Intangible and Other Assets (Note 10)	**–**	–	**11**	–
Other Long-Term Liabilities (Note 13)	**(317)**	(180)	**(165)**	(141)
	(317)	(180)	**(154)**	(141)

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

at December 31 (millions of Canadian dollars)	Pension Benefit Plans 2012	Pension Benefit Plans 2011	Other Post-Retirement Benefit Plans 2012	Other Post-Retirement Benefit Plans 2011
Benefit obligation	**(2,142)**	(1,836)	**(186)**	(170)
Plan assets at fair value	**1,825**	1,656	**32**	29
Funded Status – Deficit	**(317)**	(180)	**(154)**	(141)

The accumulated benefit obligation for all DB pension plans at December 31, 2012 is $1,966 million (2011 – $1,691 million).

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

at December 31 (millions of Canadian dollars)	2012	2011
Accumulated benefit obligation	**(1,966)**	(1,691)
Plan assets at fair value	**1,825**	1,656
Funded Status – Deficit	**(141)**	(35)

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

at December 31 (millions of Canadian dollars)	2012	2011
Accumulated benefit obligation	**(1,966)**	(446)
Plan assets at fair value	**1,825**	391
Funded Status – Deficit	**(141)**	(55)

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

Asset Category

	Percentage of Plan Assets		Target Allocations
at December 31	**2012**	**2011**	**2012**
Debt securities	**36%**	39%	**35% to 60%**
Equity securities	**64%**	61%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $2 million (0.1 per cent of total plan assets) and $2 million (0.1 per cent of total plan assets) at December 31, 2012 and 2011, respectively. Equity securities included the Company's common shares of $3 million (0.2 per cent of total plan assets) and $3 million (0.2 per cent of total plan assets) at December 31, 2012 and 2011, respectively.

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

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

at December 31 (millions of Canadian dollars)	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Asset Category										
Cash and cash equivalents	**17**	25	**–**	–	**–**	–	**17**	25	**1%**	1%
Equity Securities:										
Canadian	**400**	374	**113**	95	**–**	–	**513**	469	**28%**	28%
U.S.	**309**	251	**38**	55	**–**	–	**347**	306	**19%**	18%
International	**31**	25	**263**	231	**–**	–	**294**	256	**16%**	15%
Global	**–**	–	**13**	–	**–**	–	**13**	–	**–**	–
Fixed Income Securities:										
Canadian Bonds:										
Federal	**–**	–	**314**	303	**–**	–	**314**	303	**17%**	18%
Provincial	**–**	–	**161**	158	**–**	–	**161**	158	**9%**	9%
Municipal	**–**	–	**5**	4	**–**	–	**5**	4	**–**	–
Corporate	**–**	–	**65**	47	**–**	–	**65**	47	**4%**	3%
U.S. Bonds:										
State	**–**	–	**33**	29	**–**	–	**33**	29	**2%**	2%
Corporate	**–**	–	**45**	29	**–**	–	**45**	29	**2%**	2%
International:										
Corporate	**–**	–	**9**	9	**–**	–	**9**	9	**–**	1%
Mortgage Backed	**–**	–	**22**	30	**–**	–	**22**	30	**1%**	2%
Other Investments:										
Private Equity Funds	**–**	–	**–**	–	**19**	20	**19**	20	**1%**	1%
	757	675	**1,081**	990	**19**	20	**1,857**	1,685	**100%**	100%

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

(millions of Canadian dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2010	21
Realized and unrealized losses	(2)
Purchases and sales	1
Balance at December 31, 2011	20
Realized and unrealized losses	**(1)**
Balance at December 31, 2012	**19**

The Company's expected funding contributions in 2013 are approximately $71 million for the DB Plans and approximately $33 million for the other post-retirement benefit plans, Savings Plan and DC Plans. In addition, the Company expects to provide a $59 million letter of credit to the Canadian DB Plan.

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

(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits
2013	90	9
2014	96	9
2015	101	10
2016	107	10
2017	111	11
2018 to 2022	636	58

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2012. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

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

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2012**	**2011**	**2012**	**2011**
Discount rate	**4.35%**	5.05%	**4.35%**	5.10%
Rate of compensation increase	**3.15%**	3.15%		

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

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
Discount rate	**5.05%**	5.55%	6.00%	**5.10%**	5.60%	6.00%
Expected long-term rate of return on plan assets	**6.70%**	6.95%	6.95%	**6.40%**	6.40%	7.80%
Rate of compensation increase	**3.15%**	3.10%	3.20%			

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

A 7.5 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013 measurement purposes. The rate was assumed to decrease gradually to five per cent by

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

(millions of Canadian dollars)	**Increase**	**Decrease**
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	17	(14)

The Company's net benefit cost is as follows:

year ended December 31 (millions of Canadian dollars)	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
	2012	**2011**	**2010**	**2012**	**2011**	**2010**
Service cost	**66**	54	50	**2**	2	2
Interest cost	**94**	91	89	**8**	9	9
Expected return on plan assets	**(113)**	(114)	(108)	**(2)**	(2)	(2)
Amortization of actuarial loss	**18**	10	5	**1**	1	1
Amortization of past service cost	**2**	2	2	**1**	–	–
Amortization of regulatory asset	**19**	12	5	**1**	1	1
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net Benefit Cost Recognized	**86**	55	43	**13**	13	13

Pre-tax amounts recognized in AOCI were as follows:

at December 31 (millions of Canadian dollars)	**2012**		**2011**		**2010**	
	Pension Benefits	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**362**	**33**	282	29	179	24
Prior service cost	**5**	**2**	7	2	9	2
	367	**35**	289	31	188	26

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost in 2013 are $31 million and $2 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost in 2013 is $2 million and nil, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian dollars)	**2012**		**2011**		**2010**	
	Pension Benefits	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to OCI	**(19)**	**(1)**	(10)	(1)	(5)	(1)
Amortization of prior service costs from AOCI to OCI	**(2)**	**–**	(2)	–	(2)	–
Funded status adjustment	**99**	**5**	113	6	15	4
	78	**4**	101	5	8	3

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TCPL has exposure to market risk and counterparty credit risk. TCPL engages in risk management activities with the objective of mitigating the impact of these risks on earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

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

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

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

Where possible, derivative instruments are designated as hedges, but in some cases derivatives 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, however, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk

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

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate operational and price risks in its asset portfolio.

- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's normal purchases and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk

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

Foreign Exchange and Interest Rate Risk

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

A portion of TCPL's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TCPL's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TCPL has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

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

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

Net Investment in Foreign Operations

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2012, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $11.1 billion (US$11.2 billion) (2011 – $10 billion (US$9.8 billion)) and a fair value of $14.3 billion (US$14.4 billion) (2011 – $12.7 billion (US$12.5 billion)). At December 31, 2012, $71 million (December 31, 2011 – $79 million) was included in Other Current Assets, $47 million (December 31, 2011 – $66 million) was included in Intangible and Other Assets, $6 million (December 31, 2011 – $15 million) was included in Accounts Payable and Other, and $30 million (December 31, 2011 – $41 million) was included in Other Long-Term Liabilities for the fair value of the forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Asset/(Liability)

at December 31 (millions of Canadian dollars)	2012 Fair Value[1]	2012 Notional or Principal Amount	2011 Fair Value[1]	2011 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2013 to 2019)[2]	**82**	**US 3,800**	93	US 3,850
U.S. dollar forward foreign exchange contracts (maturing 2013)	**–**	**US 250**	(4)	US 725
	82	**US 4,050**	89	US 4,575

1 Fair values equal carrying values.

2 Net Income in 2012 included net realized gains of $30 million (2011 – gains of $27 million) related to the interest component of cross-currency swap settlements.

Counterparty Credit Risk

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

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

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 carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. 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 December 31, 2012, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2012, the Company had a credit risk concentration of $259 million (2011 – $274 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

As a level of uncertainty continues to exist in the global financial markets, TCPL continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TCPL reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms.

As part of its ongoing operations, TCPL must balance its market and counterparty credit risks when making business decisions.

Fair Values

Non-derivative Instruments

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangible and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Other Long-Term Liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. The fair value of available for sale assets has been calculated using quoted market prices where available.

Derivative Instruments

The fair value of foreign exchange and interest rate derivatives have been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives and available for sale investments 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 derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

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

	2012		2011	
at December 31 (millions of Canadian dollars)	**Carrying Amount**[1]	**Fair Value**[2]	**Carrying Amount**[1]	**Fair Value**[2]
Financial Assets				
Cash and cash equivalents	**537**	**537**	629	629
Accounts receivable and other[3]	**1,324**	**1,373**	1,378	1,422
Due from TransCanada Corporation	**985**	**985**	750	750
Available for sale assets[3]	**44**	**44**	23	23
	2,890	**2,939**	2,780	2,824
Financial Liabilities[4]				
Notes payable	**2,275**	**2,275**	1,863	1,863
Accounts payable and other long-term liabilities[5]	**1,535**	**1,535**	1,330	1,330
Accrued interest	**370**	**370**	367	367
Long-term debt	**18,913**	**24,573**	18,659	23,757
Junior subordinated notes	**994**	**1,054**	1,016	1,027
	24,087	**29,807**	23,235	28,344

1 Recorded at amortized cost, except for US$350 million (2011 – US$350 million) of Long-Term Debt that is attributed to hedged risk and recorded at fair value. This debt, which is recorded at fair value on a recurring basis, is classified in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

2 The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

3 At December 31, 2012, the Consolidated Balance Sheet included financial assets of $1.1 billion (2011 – $1.1 billion) in Accounts Receivable, $40 million (2011 – $41 million) in Other Current Assets and $240 million (2011 – $247 million) in Intangible and Other Assets.

4 Consolidated Net Income in 2012 included losses of $10 million (2011 – losses of $13 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$350 million of debt at December 31, 2012 (2011 – US$350 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

5 At December 31, 2012, the Consolidated Balance Sheet included financial liabilities of $1.5 billion (2011 – $1.2 billion) in Accounts Payable and $38 million (2011 – $137 million) in Other Long-Term Liabilities.

The following tables detail the remaining contractual maturities for TCPL's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2012:

Contractual Repayments of Financial Liabilities[1]

	Payments Due by Period				
(millions of Canadian dollars)	**Total**	**2013**	**2014 and 2015**	**2016 and 2017**	**2018 and Thereafter**
Notes payable	2,275	2,275	–	–	–
Long-term debt	18,913	894	2,531	1,769	13,719
Junior subordinated notes	994	–	–	–	994
	22,182	3,169	2,531	1,769	14,713

1 The anticipated timing of settlement of derivative contracts is presented in the Derivatives Instrument Summary in this note.

Interest Payments on Financial Liabilities

	Payments Due by Period				
(millions of Canadian dollars)	**Total**	**2013**	**2014 and 2015**	**2016 and 2017**	**2018 and Thereafter**
Long-term debt	15,377	1,154	2,125	1,908	10,190
Junior subordinated notes	3,443	63	126	126	3,128
	18,820	1,217	2,251	2,034	13,318

Derivative Instruments Summary

Information for the Company's derivative instruments for 2012, excluding hedges of the Company's net investment in foreign operations, is as follows:

at December 31 (all amounts in Canadian millions unless otherwise indicated)	2012			
	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$139**	**$88**	**$1**	**$14**
Liabilities	**$(176)**	**$(104)**	**$(2)**	**$(14)**
Notional Values				
Volumes[3]				
Purchases	**31,135**	**83**	**–**	**–**
Sales	**31,066**	**65**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**620**
U.S. dollars	**–**	**–**	**US 1,408**	**US 200**
Cross-currency	**–**	**–**	**–**	**–**
Net unrealized (losses)/gains in the year[4]	**$(30)**	**$2**	**$(1)**	**$–**
Net realized gains/(losses) in the year[4]	**$5**	**$(10)**	**$26**	**$–**
Maturity dates	**2013-2017**	**2013-2016**	**2013**	**2013-2016**
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	**$76**	**$–**	**$–**	**$10**
Liabilities	**$(97)**	**$(2)**	**$(38)**	**$–**
Notional Values				
Volumes[3]				
Purchases	**15,184**	**1**	**–**	**–**
Sales	**7,200**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**US 12**	**US 350**
Cross-currency	**–**	**–**	**136/US 100**	**–**
Net realized (losses)/gains in the year[4]	**$(130)**	**$(23)**	**$–**	**$7**
Maturity dates	**2013-2018**	**2013**	**2013-2014**	**2013-2015**

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 Volumes for power and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in 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.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. In 2012, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2012, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2012, 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.

Derivative Instruments Summary

Information for the Company's derivative instruments for 2011, excluding hedges of the Company's net investment in foreign operations, is as follows:

at December 31 (all amounts in Canadian millions unless otherwise indicated)	**2011** Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$185	$176	$3	$22
Liabilities	$(192)	$(212)	$(14)	$(22)
Notional Values				
Volumes[3]				
Purchases	21,905	103	–	–
Sales	21,334	82	–	–
Canadian dollars	–	–	–	684
U.S. dollars	–	–	US 1,269	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(2)	$(50)	$(4)	$1
Net realized gains/(losses) in the year[4]	$42	$(74)	$10	$1
Maturity dates	2012-2016	2012-2016	2012	2012-2016
Derivative Instruments in Hedging Relationships[5,6]				
Fair Values[2]				
Assets	$16	$3	$–	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values				
Volumes[3]				
Purchases	17,188	8	–	–
Sales	8,061	–	–	–
U.S. dollars	–	–	US 73	US 600
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(165)	$(17)	$–	$(16)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

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

4 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative 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.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2011, 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.

Balance Sheet Presentation of Derivative Instruments

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

at December 31 (millions of Canadian dollars)	**2012**	**2011**
Current		
Other current assets (Note 5)	**259**	361
Accounts payable and other (Note 12)	**(283)**	(485)
Long Term		
Intangible and other assets (Note 10)	**187**	202
Other long-term liabilities (Note 13)	**(186)**	(349)

Derivatives in Cash Flow Hedging Relationships

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

	Cash Flow Hedges[1]							
	Power		Natural Gas		Foreign Exchange		Interest	
year ended December 31 (millions of Canadian dollars, pre-tax)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Change in fair value of derivative instruments recognized in OCI (effective portion)	**83**	(263)	**(21)**	(59)	**(1)**	5	**–**	(1)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**147**	81	**54**	100	**–**	–	**18**	43
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**7**	–	**–**	–	**–**	–	**–**	–

1 No amounts have been excluded from the assessment of hedge effectiveness.

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2012, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $37 million (2011 – $110 million), for which the Company has provided collateral of nil (2011 – $28 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2012, the Company would have been required to provide additional collateral of $37 million (2011 – $82 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

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

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and natural gas commodity assets and liabilities is determined using the market approach. Under both approaches, valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in 2012 or 2011.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. 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. There were no transfers out of Level II and into Level III in 2012 or 2011.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. Long-term electricity prices are estimated using a third-party modelling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Inputs into the model 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. Long-term prices are reviewed by management and the Board on a periodic basis. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas would result in a lower fair value measurement of contracts included in Level III.

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:

December 31 (millions of Canadian dollars, pre-tax)	**Quoted Prices in Active Markets (Level I)**		**Significant Other Observable Inputs (Level II)**		**Significant Unobservable Inputs (Level III)**		**Total**	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Derivative Instrument Assets:								
Interest rate contracts	**–**	–	**24**	35	**–**	–	**24**	35
Foreign exchange contracts	**–**	–	**119**	142	**–**	–	**119**	142
Power commodity contracts	**–**	–	**213**	201	**2**	–	**215**	201
Gas commodity contracts	**75**	124	**13**	55	**–**	–	**88**	179
Derivative Instrument Liabilities:								
Interest rate contracts	**–**	–	**(14)**	(23)	**–**	–	**(14)**	(23)
Foreign exchange contracts	**–**	–	**(76)**	(102)	**–**	–	**(76)**	(102)
Power commodity contracts	**–**	–	**(269)**	(454)	**(4)**	(15)	**(273)**	(469)
Gas commodity contracts	**(95)**	(208)	**(11)**	(26)	**–**	–	**(106)**	(234)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**44**	23	**–**	–	**–**	–	**44**	23
	24	(61)	**(1)**	(172)	**(2)**	(15)	**21**	(248)

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

(millions of Canadian dollars, pre-tax)	**Derivatives**[1,2]
Balance at December 31, 2010	(8)
New contracts	1
Settlements	2
Transfers out of Level III	3
Total losses included in OCI	(13)
Balance at December 31, 2011	(15)
Settlements	**(1)**
Transfers out of Level III	**(21)**
Total gains included in Net Income	**11**
Total gains included in OCI	**24**
Balance at December 31, 2012	**(2)**

1 The fair value of derivative assets and liabilities is presented on a net basis.

2 At December 31, 2012, there were unrealized gains included in Net Income attributable to derivatives that were still held at the reporting date of $1 million (2011 – 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 December 31, 2012.

22. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian dollars)	**2012**	**2011**	**2010**
Decrease/(increase) in accounts receivable	**50**	(34)	(277)
Decrease in inventories	**27**	3	25
Decrease/(increase) in other current assets	**64**	(15)	(90)
Increase in accounts payable and other	**146**	243	64
Increase/(decrease) in accrued interest	**–**	10	(14)
Decrease/(Increase) in Operating Working Capital	**287**	207	(292)

23. ACQUISITIONS AND DISPOSITIONS

Energy

CrossAlta

On December 18, 2012, TCPL purchased BP's 40 per cent interest in the assets of the Crossfield Gas Storage facility and BP's interest in CrossAlta Gas Storage & Services Ltd. (collectively CrossAlta) for $214 million in cash, net of cash acquired, resulting in the Company owning and operating 100 per cent of these operations. The acquisition will enhance TCPL's ability to deliver reliable services to the natural gas markets in western Canada and is consistent with TCPL's growth strategy for its natural gas storage business.

The Company measured the assets and liabilities acquired at fair value and the transaction resulted in no goodwill. Pro-forma revenues and earnings for the years ended December 31, 2012 and 2011, assuming the acquisition had occurred at the beginning of the period, would not be materially different from reported results.

Upon acquisition, TCPL began consolidating CrossAlta. Prior to the acquisition, TCPL applied equity accounting to its 60 per cent ownership interest in CrossAlta.

Natural Gas Pipelines

TC PipeLines, LP

On May 3, 2011, TCPL completed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million which included US$81 million of long-term debt, or 25 per cent of GTN LLC's outstanding debt. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Net proceeds of approximately US$331 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on TC PipeLines, LP's bridge loan facility and US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TCPL made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TCPL's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Additional Paid-In Capital.

24. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

year ended December 31 (millions of Canadian dollars)	**Minimum Lease Payments**	**Amounts Recoverable under Sub-leases**	**Net Payments**
2013	82	(8)	74
2014	80	(8)	72
2015	80	(7)	73
2016	81	(4)	77
2017	80	(2)	78
2018 and thereafter	374	(1)	373
	777	(30)	747

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 10 years. Net rental expense on operating leases in 2012 was $84 million (2011 – $79 million; 2010 – $80 million).

TCPL's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability and other factors. TCPL's share of payments under the PPAs in 2012 was $303 million (2011 – $394 million; 2010 – $363 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	**Expiry Date**
Sundance A	560	December 31, 2017
Sundance B[1]	353	December 31, 2020
Sheerness	756	December 31, 2020

1 Held within TCPL's 50 per cent interest in ASTC Power Partnership.

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

Other Commitments

At December 31, 2012, TCPL was committed to Natural Gas Pipelines capital expenditures totalling approximately $1,322 million, primarily related to construction costs related to the Alberta System and Mexico pipeline projects.

At December 31, 2012, the Company was committed to Oil Pipelines capital expenditures totalling approximately $1,732 million, primarily related to construction costs of Keystone XL and the Gulf Coast Project.

At December 31, 2012, the Company was committed to Energy capital expenditures totalling approximately $62 million and related to capital costs of the Napanee Generating Station.

On December 15, 2011, TCPL agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for $476 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TCPL will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the Ontario Power Authority (OPA) under the Feed-in Tariff program in Ontario. TCPL anticipates the projects will be placed in service between early 2013 and late 2014, subject to regulatory approvals.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2012, the Company had accrued approximately $37 million (2011 – $49 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

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

Guarantees

TCPL and its joint venture partners on Bruce B, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The Bruce B guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it. In addition, TCPL and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the OPA to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019. TCPL's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $897 million at December 31, 2012. The carrying amount of these Bruce Power guarantees at December 31, 2012 is estimated to be $10 million which has been included in Other Long-Term Liabilities. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging from 2013 to 2040. TCPL's share of the potential exposure under these assurances was estimated at December 31, 2012 to range from $43 million to a maximum of $89 million. The carrying amount of these guarantees at December 31, 2012 is estimated to be $7 million, which has been included in Other Long-Term 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.

25. RELATED PARTY TRANSACTIONS

The following amounts are included in Due from TransCanada Corporation:

(millions of dollars)	Maturity Dates	2012 Outstanding December 31	2012 Effective Interest Rate	2011 Outstanding December 31	2011 Effective Interest Rate
Discount Notes[1]	2013	**2,889**	**1.4%**	2,849	1.4%
Credit Facility[2]		**(1,240)**	**3.0%**	(1,435)	3.0%
Credit Facility[3]	2014	**(664)**	**3.8%**	(664)	3.8%
		985		750	

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

2 TCPL's demand revolving credit facility 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.

3 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.

In 2012, Interest Expense included $61 million (2011 – $140 million; 2010 – $70 million) of interest charges and $41 million (2011 – $35 million; 2010 – $19 million) of interest income as a result of inter-corporate borrowing. At December 31, 2012, Accounts Payable included $2 million of interest payable to TransCanada (2011 – $2 million).

The Company made interest payments of $62 million to TransCanada in 2012 (2011 – $144 million; 2010 – $66 million).

26. SUBSEQUENT EVENTS

On January 15, 2013, TCPL issued US$750 million of Senior Notes maturing January 15, 2016 and bearing interest at 0.75 per cent.

On January 17, 2013, TCPL issued 7.2 million common shares to TransCanada resulting in proceeds of $345 million.