NewsRelease

TransCanada Reports Strong Fourth Quarter and Year-End Financial Results
Common Share Dividend Increased Eight Per Cent to $2.08 Per Share Annually

CALGARY, Alberta – **February 13, 2015** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for fourth quarter 2014 of $458 million or $0.65 per share compared to $420 million or $0.59 per share for the same period in 2013. For the year ended December 31, 2014, net income attributable to common shares was $1.7 billion or $2.46 per share compared to $1.7 billion or $2.42 per share in 2013. Comparable earnings for fourth quarter 2014 were $511 million or $0.72 per share compared to $410 million or $0.58 per share for the same period last year. For the year ended December 31, 2014, comparable earnings were $1.7 billion or $2.42 per share compared to $1.6 billion or $2.24 per share in 2013. TransCanada's Board of Directors also declared a quarterly dividend of $0.52 per common share for the quarter ending March 31, 2015, equivalent to $2.08 per common share on an annualized basis, an increase of eight per cent. This is the fifteenth consecutive year the Board of Directors has raised the dividend.

"Comparable earnings and funds generated from operations in 2014 increased eight per cent and seven per cent, respectively compared to last year," said Russ Girling, TransCanada's president and chief executive officer. "Our strong performance reflects the diversity and stability of our complementary businesses and $3.8 billion of new assets that were placed into service in 2014. Looking forward, the resiliency of our business model and a strong balance sheet leaves us well positioned to continue to create shareholder value under various market conditions.

"With an additional $12 billion of small-to-medium sized projects expected to be completed and placed into service by the end of 2017, and the steps we have taken to solidify the long-term returns from existing assets such as the Canadian Mainline and ANR, we are also pleased to announce an eight per cent increase in the common share dividend," added Girling. "Our financial strength and flexibility provides us with the capacity to raise the dividend and continue to prudently fund our industry-leading capital program."

Over the course of 2014, we captured approximately $7 billion of new projects primarily related to our Canadian regulated natural gas pipeline business. With these additions, our capital program now includes $46 billion of commercially secured projects which are backed by long-term contracts or cost of service business models. We continue to advance this unprecedented slate of growth initiatives, with many currently under construction or proceeding through their respective regulatory processes. Over the remainder of the decade, subject to required approvals, this blue-chip portfolio of contracted energy infrastructure is expected to generate significant sustainable growth in earnings, cash flow and dividends.

Fourth Quarter and Year-End Highlights

(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- Fourth quarter financial results:
  - Net income attributable to common shares of $458 million or $0.65 per share
  - Comparable earnings of $511 million or $0.72 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.5 billion
  - Funds generated from operations of $1.2 billion
- For the year ended December 31, 2014:
  - Net income attributable to common shares of $1.7 billion or $2.46 per share
  - Comparable earnings of $1.7 billion or $2.42 per share
  - Comparable EBITDA of $5.5 billion
  - Funds generated from operations of $4.3 billion
- Announced an increase in the quarterly common share dividend of eight per cent to $0.52 per share for the quarter ending March 31, 2015
- Received National Energy Board (NEB) approval for our Canadian Mainline 2015-2030 Tolls Application

- Filed regulatory applications with the NEB for the $12 billion Energy East Project and the $1.5 billion Eastern Mainline Project on October 30, 2014
- Received Environmental Assessment Certificates (EAC) from the B.C. Environmental Assessment Office (BC EAO) for Coastal GasLink and Prince Rupert Gas Transmission
- Commenced construction on the $1.5 billion Grand Rapids Pipeline Project and the $1 billion Napanee Power Project
- Nebraska State Supreme Court vacated a lower court's ruling that the law approving the route for the Keystone XL project was unconstitutional. The current route through Nebraska remains valid.
- Closed the $60 million purchase of an additional solar facility in Ontario in late December
- Closed the sale of our remaining 30 per cent interest in the Bison pipeline and announced our intention to sell our remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP as part of advancing our master limited partnership drop down strategy

Net income attributable to common shares increased by $38 million to $458 million or $0.65 per share for the three months ended December 31, 2014 compared to the same period in 2013. Both years included unrealized gains and losses from changes in certain risk management activities. Fourth quarter 2014 results also included an $8 million after-tax gain from the sale of Gas Pacifico/INNERGY.

Net income attributable to common shares for the year ended December 31, 2014 was $1.7 billion or $2.46 per share compared to $1.7 billion or $2.42 per share in 2013. Results in 2014 included a net after-tax gain of $99 million from the sale of Cancarb and its related power generation facility, an after-tax $32 million expense for terminating a natural gas storage contract and an $8 million after-tax gain from the sale of Gas Pacifico/ INNERGY. Results in 2013 included $84 million of net income related to the 2012 impact of the 2013 NEB decision on the Canadian Mainline as well as a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax. These amounts, along with unrealized gains and losses on risk management activities, were excluded from comparable earnings.

Comparable earnings for fourth quarter 2014 were $511 million or $0.72 per share compared to $410 million or $0.58 per share for the same period in 2013. Higher earnings from the Keystone Pipeline System, the Canadian Mainline, Mexican Pipelines and U.S. Power were partially offset by higher interest expense.

Comparable earnings for the year ended December 31, 2014 were $1.7 billion or $2.42 per share compared to $1.6 billion or $2.24 per share in 2013. Higher earnings from the Keystone Pipeline System, the Canadian Mainline, Mexican Pipelines, U.S. and International Pipelines, Eastern Power and U.S. Power were partially offset by higher interest expense and lower contributions from Western Power.

Notable recent developments in Liquids Pipelines, Natural Gas Pipelines, Energy and Corporate include:

Liquids Pipelines:

- *Energy East Pipeline:* On October 30, 2014, we filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries by the end of 2018.

  The Energy East Pipeline includes a proposed marine terminal near Cacouna, Québec which would be adjacent to a beluga whale habitat. On December 8, 2014, the Committee on the Status of Endangered Wildlife in Canada recommended that beluga whales be placed on the endangered species list. As a result, we have made the decision to halt any further work at Cacouna and will be analyzing the recommendation, assessing any impacts to the project and reviewing all viable options. We intend to make a decision on how to proceed by the end of first quarter 2015.

  The 1.1 million barrel per day (Bbl/d) Energy East Pipeline received approximately one million Bbl/d of firm, long-term contracts to transport crude oil from western Canada that were secured during binding open seasons.

- *Keystone XL:* In February 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Heineman, had the authority to approve an alternative route through Nebraska for the Keystone XL project. Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court on September 5, 2014. On January 9, 2015, the Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.

  In September 2014, we filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (PUC) which confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continue to be satisfied. The formal hearing for the certification is scheduled for May 2015.

  On January 16, 2015, the U.S. Department of State (DOS) re-initiated the national interest review and requested the eight federal agencies with a role in the review to complete their consideration of whether Keystone XL serves the national interest and to provide their views to the DOS by February 2, 2015.

  On February 2, 2015, the U.S. Environmental Protection Agency (EPA) posted a comment letter to its website suggesting that, among other things, the Final Supplemental Environmental Impact Statement issued by the DOS has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. On February 10, 2015, we sent a letter to the DOS refuting these and other comments in the EPA letter but also offering to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL.

  The estimated capital cost for Keystone XL is approximately US$8.0 billion. As of December 31, 2014, we have invested US$2.4 billion in the project and have also recorded capitalized interest in the amount of US$0.4 billion.

- *Northern Courier*: In July 2014, the Alberta Energy Regulator issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the $900 million, 90 kilometre (km) (56 mile) pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. We currently expect the pipeline to be ready for service in 2017.

- *Grand Rapids Pipeline Project:* On October 9, 2014, the Alberta Energy Regulator issued a permit approving our application to construct and operate the Grand Rapids Pipeline. We have a partner through a joint venture, to develop Grand Rapids, a 460 km (287 mile) crude oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region. Each partner will own 50 per cent of the $3 billion pipeline project, and we will be the operator. Our partner has also entered into a long-term transportation service contract in support of Grand Rapids. Construction has commenced with initial crude oil transportation planned in 2016.

- *Upland Pipeline:* In November 2014, we completed a successful binding open season for the Upland Pipeline. The $600 million pipeline would provide crude oil transportation between multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan.

  Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2018. The commercial contracts we have executed for Upland Pipeline are conditioned on Energy East Pipeline proceeding.

Natural Gas Pipelines:

- *NGTL System Expansions:* We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets driven primarily by oil sands development and demand for gas-fired electric power generation. This demand for NGTL System services is expected to result in a total of approximately 4.0 billion cubic feet per day (Bcf/d) of incremental firm service contracts. Approximately 3.1 Bcf/d of this volume relates to firm receipt service and 0.9 Bcf/d relates to firm delivery service. Significant new facilities consisting of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations will be required in 2016 and 2017 (2016/17 Facilities) to meet these service requests. We will be seeking regulatory approval in 2015 to construct the new facilities which have an estimated total capital cost of $2.7 billion.

  Including the new 2016/17 Facilities, the North Montney Mainline, the Merrick Mainline, and other new supply and demand facilities, the NGTL System has approximately $6.7 billion of projects in development which have been or will be filed with the NEB for approval.

- *NGTL System Revenue Requirement Settlement:* We received NEB approval on February 2, 2015 for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include no changes to the return on equity of 10.1 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administrative expense amount that is based on an escalation of 2014 actual costs.

- *Canadian Mainline 2015 - 2030 Tolls and Tariff Application:* On November 28, 2014, the NEB approved the Canadian Mainline's 2015 - 2030 Tolls and Tariff Application. The application reflected components of a settlement between the Canadian Mainline and the three major local distribution companies in Ontario and Québec. The approval of this application provides a long term commercial platform for both the Canadian Mainline and its shippers with a known toll design for 2015 to 2020 and certain parameters for a toll-setting methodology up to 2030. The platform balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets.

  Highlights of the approved application include a revenue requirement along with an incentive sharing mechanism that targets a return of 10.1 per cent on a deemed common equity of 40 per cent, with a possible range of outcomes from 8.7 per cent to 11.5 per cent.

- *Canadian Mainline Expansions:* On October 30, 2014, we filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario. The new facilities are a result of the proposed transfer of a portion of Canadian Mainline capacity to crude oil from natural gas service as part of our Energy East Pipeline and an open season that closed in January 2014. The $1.5 billion Eastern Mainline Project will add 0.6 Bcf/d of new capacity in the Eastern Triangle segment of the Canadian Mainline and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments. The project is contingent upon the Energy East Project.

  In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities. Subject to regulatory approval, these projects will provide capacity needed to meet customer requirements in Eastern Canada and have a total capital cost estimate of $475 million, with expected in-service dates between November 1, 2015 and November 1, 2016.

- *Bison and GTN Sales*: On October 1, 2014, our remaining 30 per cent interest in the Bison pipeline was sold to our master limited partnership, TC PipeLines, LP (the Partnership) for cash proceeds of US$215 million.

On November 12, 2014, we announced an offer to sell our remaining 30 per cent interest in the GTN Pipeline to the Partnership. Subject to the satisfactory negotiation of terms and Partnership Board approval, the transaction is expected to close in late first quarter 2015.

These transactions advance our previously stated commitment to sell the remainder of TransCanada's U.S. natural gas pipeline assets to the Partnership to help fund our capital program and enhance the size and diversity of the Partnership's asset base, positioning it with visible, high quality future growth. Including GTN, the U.S. natural gas pipeline assets that remain directly-held by TransCanada are expected to generate approximately US$480 million of EBITDA in 2016.

At December 31, 2014, we held a 28.3 per cent interest in TC PipeLines, LP.

- *Tamazunchale Pipeline Extension Project:* Construction of the US$600 million extension was completed November 6, 2014. Delays from the original service commencement date of March 9, 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue as per the original service commencement date.

- *Coastal GasLink Pipeline Project:* In October 2014, the BC EAO issued an EAC for the Coastal GasLink Pipeline Project. In 2014, we also submitted applications to the B.C. Oil and Gas Commission (BC OGC) for the permits required to build and operate Coastal GasLink. Regulatory review of those applications is progressing, with permit decisions anticipated in first quarter 2015. We are currently continuing our engagement with Aboriginal groups and stakeholders along the pipeline route and are advancing detailed engineering and construction planning work to support the regulatory applications and refine the capital cost estimates in advance of a final investment decision (FID), which is expected to be made by LNG Canada in early 2016.

- *Prince Rupert Gas Transmission Project:* On November 25, 2014, we received an EAC from the BC EAO. We have submitted our permit applications to the BC OGC for construction of the pipeline and anticipate receiving these permits in first quarter 2015.

  We have made significant changes to the project route since first announced, increasing it by 150 km (90 miles) to 900 km (560 miles), taking into account First Nations and stakeholder input. We continue to work closely with First Nations and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. In October 2014, we concluded a benefits agreement with the Nisga’a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.

  On December 3, 2014, our customer announced the deferral of a FID. We continue to work with our contractors to refine capital cost estimates for the project. Once the permitting process with the BC OGC is complete and Pacific NorthWest LNG secures the necessary regulatory approvals and proceeds with a positive FID, we will be in a position to begin construction. All costs would be fully recoverable should the project not proceed. The deferral of a FID past the end of 2014 has resulted in a deferral of the expected in-service date for the pipeline. The in-service date will depend on when our customer receives the necessary regulatory approvals and is in a position to make a FID.

Energy:

- *Napanee Project:* In January 2015, we began construction activities on the 900 megawatt (MW) natural gas-fired power plant at Ontario Power Generation’s Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted for 20 years with the Independent Electricity System Operator (IESO).

- *Ontario Solar:* As part of a purchase agreement with Canadian Solar Solutions Inc., we acquired our eighth facility for $60 million in December 2014. Our total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year power purchase arrangements with the IESO.

- *Ravenswood:* In late September 2014, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings although the recording of earnings may not coincide with lost revenues due to timing of the anticipated insurance proceeds. The unit is expected to be back in service in the first half of 2015.

Corporate:

- *Common Dividend:* Our Board of Directors declared a quarterly dividend of $0.52 per share for the quarter ending March 31, 2015 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.08 per common share on an annualized basis and represents an eight per cent increase over the previous amount.

- *Preferred Share Rate Reset and Conversion:* In December 2014, Series 1 shareholders converted 12.5 million of our 22 million outstanding Series 1 Cumulative Redeemable First Preferred Shares, on a one-for-one basis into Series 2 floating-rate Cumulative Redeemable First Preferred Shares. The rate on the Series 1 Shares was reset and they will pay an annual fixed dividend rate of 3.266 per cent on a quarterly basis for the five-year period which began on December 31, 2014. The Series 2 Shares will pay a floating quarterly dividend for the same five-year period. The quarterly dividend rate for the Series 2 Shares for the first quarterly floating rate period (December 31, 2014 to but excluding March 31, 2015) is 2.815 per cent per annum and will be reset every quarter going forward.

- *Financing Activity:* In January 2015, we issued US$500 million of three-year fixed rate senior notes bearing interest at 1.875 per cent, and US$250 million of three-year LIBOR-based floating rate senior notes, bearing interest at an initial rate of 1.045 per cent, both maturing on January 12, 2018.

  The net proceeds of these offerings are intended to be used for general corporate purposes and to reduce short-term indebtedness which was used to fund a portion of our capital program and for general corporate purposes.

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Friday, February 13, 2015 to discuss our fourth quarter 2014 financial results. Russ Girling, TransCanada president and chief executive officer, and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 1:00 p.m. (MT) / 3:00 p.m. (ET).

Analysts, members of the media and other interested parties are invited to participate by calling 800.396.7098 or 416.340.2218 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at **www.transcanada.com**.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on February 20, 2015. Please call 800.408.3053 or 905.694.9451 and enter pass code 2631193.

With more than 60 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,500 kilometres (42,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with more than 400 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,800 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: **www.transcanada.com** or check us out on Twitter @TransCanada or **http://blog.transcanada.com**.

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Fourth quarter 2014 and financial highlights

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Income				
Revenue	**2,616**	2,332	**10,185**	8,797
Net income attributable to common shares	**458**	420	**1,743**	1,712
per common share - basic and diluted	**$0.65**	$0.59	**$2.46**	$2.42
Comparable EBITDA[1]	**1,521**	1,291	**5,521**	4,859
Comparable earnings[1]	**511**	410	**1,715**	1,584
per common share[1]	**$0.72**	$0.58	**$2.42**	$2.24
Operating cash flow				
Funds generated from operations[1]	**1,178**	1,083	**4,268**	4,000
Decrease/(increase) in operating working capital	**12**	(74)	**(189)**	(326)
Net cash provided by operations	**1,190**	1,009	**4,079**	3,674
Investing activities				
Capital spending - capital expenditures	**1,128**	1,311	**3,550**	4,264
Capital spending - projects under development	**330**	297	**807**	488
Equity investments	**61**	62	**256**	163
Acquisitions, net of cash acquired	**60**	62	**241**	216
Proceeds from sale of assets, net of transaction costs	**9**	—	**196**	—
Dividends declared				
per common share	**$0.48**	$0.46	**$1.92**	$1.84
Basic common shares outstanding (millions)				
Average for the period	**709**	707	**708**	707
End of period	**709**	707	**709**	707

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

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 news release may include information about the following, among other things:

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

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

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

Assumptions

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

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations

- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

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

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

FOR MORE INFORMATION

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

NON-GAAP MEASURES

We use the following non-GAAP measures:

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

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

EBITDA and EBIT

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

Funds generated from operations

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

Comparable measures

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

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

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

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

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

Consolidated results - fourth quarter 2014

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2014**	**2013**	**2014**	**2013**
Natural Gas Pipelines	**621**	498	**2,187**	1,881
Liquids Pipelines	**230**	160	**843**	603
Energy	**219**	301	**1,051**	1,113
Corporate	**(43)**	(35)	**(150)**	(124)
Total segmented earnings	**1,027**	924	**3,931**	3,473
Interest expense	**(323)**	(240)	**(1,198)**	(985)
Interest income and other	**28**	1	**91**	34
Income before income taxes	**732**	685	**2,824**	2,522
Income tax expense	**(206)**	(208)	**(831)**	(611)
Net income	**526**	477	**1,993**	1,911
Net income attributable to non-controlling interests	**(43)**	(38)	**(153)**	(125)
Net income attributable to controlling interests	**483**	439	**1,840**	1,786
Preferred share dividends	**(25)**	(19)	**(97)**	(74)
Net income attributable to common shares	**458**	420	**1,743**	1,712
Net income per common share - basic and diluted	**$0.65**	$0.59	**$2.46**	$2.42

Net income attributable to common shares increased by $38 million for the three months ended December 31, 2014 compared to the same period in 2013 and included an after tax gain on the sale of Gas Pacifico/INNERGY of $8 million as well as unrealized gains and losses from changes in certain risk management activities. Excluding the impact of these items, comparable earnings in the three months ended December 31, 2014 increased over the same period in 2013, as discussed below in Reconciliation of Net Income to Comparable Earnings.

Net income attributable to common shares increased by $31 million for the year ended December 31, 2014 compared to 2013. The following specific items were recognized in net income:

2014

- a gain on the sale of Cancarb Limited and its related power generation business of $99 million after tax
- a net loss resulting from a termination payment to Niska Gas Storage for contract restructuring of $32 million after tax
- a gain on the sale of our 30 per cent interest in Gas Pacifico/INNERGY of $8 million after tax

2013

- net income of $84 million related to 2012 from the 2013 NEB Decision
- a favourable tax adjustment of $25 million due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax.

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

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Net income attributable to common shares	**458**	420	**1,743**	1,712
Specific items (net of tax):				
Cancarb gain on sale	**—**	—	**(99)**	—
Niska contract termination	**—**	—	**32**	—
Gas Pacifico/ INNERGY gain on sale	**(8)**	—	**(8)**	—
2013 NEB decision - 2012	**—**	—	**—**	(84)
Part VI.I income tax adjustment	**—**	—	**—**	(25)
Risk management activities[1]	**61**	(10)	**47**	(19)
Comparable earnings	**511**	410	**1,715**	1,584
Net income per common share	**$0.65**	$0.59	**$2.46**	$2.42
Specific items (net of tax):				
Cancarb gain on sale	**—**	—	**(0.14)**	—
Niska contract termination	**—**	—	**0.04**	—
Gas Pacifico/ INNERGY gain on sale	**(0.01)**	—	**(0.01)**	—
2013 NEB decision - 2012	**—**	—	**—**	(0.12)
Part VI.I income tax adjustment	**—**	—	**—**	(0.04)
Risk management activities[1]	**0.08**	(0.01)	**0.07**	(0.02)
Comparable earnings per share	**$0.72**	$0.58	**$2.42**	$2.24

1

Risk management activities (unaudited - millions of $)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Canadian Power	**(11)**	(2)	**(11)**	(4)
U.S. Power	**(85)**	36	**(55)**	50
Natural Gas Storage	**9**	(5)	**13**	(2)
Foreign exchange	**(12)**	(9)	**(21)**	(9)
Income tax attributable to risk management activities	**38**	(10)	**27**	(16)
Total (losses)/gains from risk management activities	**(61)**	10	**(47)**	19

Comparable earnings increased by $101 million for the three months ended December 31, 2014 compared to the same period in 2013. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- higher earnings from Canadian Mainline due to higher incentive earnings recorded in fourth quarter
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from Eastern Power due to higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in December 2013 and the second half of 2014
- higher earnings from U.S. Power due to higher generation, higher sales to wholesale, commercial and industrial customers and the impact of higher realized power and capacity prices
- higher interest expense from debt issuances and lower capitalized interest on projects placed in service.

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

CAPITAL PROGRAM

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

Our capital program is comprised of $12 billion of small to medium-sized projects and $34 billion of large scale projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at December 31, 2014 (unaudited - billions of $)	**Segment**	**Expected In-Service Date**	**Estimated Project Cost**	**Amount Spent**
Small to medium sized, shorter-term				
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.6	US 0.4
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.7
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.2
Grand Rapids[1]	Liquids Pipelines	2016-2017	1.5	0.2
Heartland and TC Terminals	Liquids Pipelines	2017	0.9	0.1
Northern Courier	Liquids Pipelines	2017	0.9	0.2
Canadian Mainline - Other	Natural Gas Pipelines	2015-2016	0.5	—
NGTL System - North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
- 2016/17 Facilities	Natural Gas Pipelines	2016-2017	2.7	—
- Other	Natural Gas Pipelines	2015-2016	0.4	0.1
Napanee	Energy	2017 or 2018	1.0	0.1
			11.6	2.1
Large-scale, medium and longer-term				
Upland	Liquids Pipelines	2018	0.6	—
Keystone Projects				
Keystone XL[2]	Liquids Pipelines	[3]	US 8.0	US 2.4
Keystone Hardisty Terminal	Liquids Pipelines	[3]	0.3	0.1
Energy East projects				
Energy East[4]	Liquids Pipelines	2018	12.0	0.5
Eastern Mainline	Natural Gas Pipelines	2017	1.5	—
BC west coast LNG-related projects				
Coastal GasLink	Natural Gas Pipelines	2019+	4.8	0.2
Prince Rupert Gas Transmission	Natural Gas Pipelines	2019+	5.0	0.3
NGTL System - Merrick	Natural Gas Pipelines	2020	1.9	—
			34.1	3.5
			45.7	5.6

1 Represents our 50 per cent share.
2 Estimated project cost dependent on the timing of the Presidential permit.
3 Approximately two years from the date the Keystone XL permit is received.
4 Excludes transfer of Canadian Mainline natural gas assets.

Natural Gas Pipelines

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

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable EBITDA	**884**	778	**3,241**	2,852
Comparable depreciation and amortization[1]	**(272)**	(280)	**(1,063)**	(1,013)
Comparable EBIT	**612**	498	**2,178**	1,839
Specific items:				
Gas Pacifico/INNERGY gain on sale	**9**	—	**9**	—
2013 NEB decision - 2012	**—**	—	**—**	42
Segmented earnings	**621**	498	**2,187**	1,881

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

Natural Gas Pipelines segmented earnings increased by $123 million for the three months ended December 31, 2014 compared to the same period in 2013 and included a $9 million pre-tax gain related to the sale of Gas Pacifico/INNERGY in November 2014. This amount has been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Canadian Pipelines				
Canadian Mainline	**396**	305	**1,334**	1,121
NGTL System	**219**	261	**856**	846
Foothills	**26**	28	**106**	114
Other Canadian pipelines[1]	**5**	6	**22**	26
Canadian Pipelines - comparable EBITDA	**646**	600	**2,318**	2,107
Comparable depreciation and amortization	**(208)**	(225)	**(821)**	(790)
Canadian Pipelines - comparable EBIT	**438**	375	**1,497**	1,317
U.S. and International Pipelines (US$)				
ANR	**47**	33	**189**	188
TC PipeLines, LP[1,2]	**23**	21	**88**	72
Great Lakes[3]	**13**	10	**49**	34
Other U.S. pipelines (Bison[4], Iroquois[1], GTN[5], Portland[6])	**32**	37	**132**	183
Mexico (Guadalajara, Tamazunchale)	**43**	23	**160**	100
International and other[1,7]	**(5)**	(1)	**(10)**	(4)
Non-controlling interests[8]	**65**	60	**241**	186
U.S. and International Pipelines - comparable EBITDA	**218**	183	**849**	759
Comparable depreciation and amortization	**(57)**	(53)	**(219)**	(217)
U.S. and International Pipelines - comparable EBIT	**161**	130	**630**	542
Foreign exchange impact	**24**	7	**68**	15
U.S. and International Pipelines - comparable EBIT (Cdn$)	**185**	137	**698**	557
Business Development comparable EBITDA and EBIT	**(11)**	(14)	**(17)**	(35)
Natural Gas Pipelines - comparable EBIT	**612**	498	**2,178**	1,839

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

2 In August 2014, TC PipeLines, LP began its at-the-market equity issuance program which will decrease our ownership interest in TC PipeLines, LP going forward. Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent interest in Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	October 1, 2014	July 1, 2013	May 22, 2013	January 1, 2013
TC PipeLines, LP	28.3	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:				
Bison	28.3	20.2	7.2	8.3
GTN	19.8	20.2	7.2	8.3
Great Lakes	13.1	13.4	13.4	15.5

3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

4 Effective October 1, 2014 we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013 and 75 per cent effective May 2011.

5 Effective July 1, 2013, represents our 30 per cent direct ownership interest. Prior to July 1, 2013, our direct ownership interest was 75 per cent effective May 2011.

6 Represents our 61.7 per cent ownership interest.

7 Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

8 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

CANADIAN PIPELINES

Net income and comparable EBITDA for our rate-regulated Canadian pipelines are affected by the approved ROE, investment base, level of deemed common equity, carrying charges owed to shippers on the Canadian Mainline Tolls Stabilization Account (TSA), and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA and comparable EBIT but do not impact net income as they are recovered in revenue on a flow-through basis.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	2013	**2014**	2013
Canadian Mainline - net income	**115**	76	**300**	361
Canadian Mainline - comparable earnings	**115**	76	**300**	277
NGTL System	**59**	72	**241**	243
Foothills	**4**	5	**17**	18

Net income and comparable earnings for the Canadian Mainline increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher incentive earnings recorded in the fourth quarter partially offset by higher carrying charges owed to shippers on the positive TSA balance. Results for both periods reflect an ROE of 11.50 per cent on deemed common equity of 40 per cent.

Net income for the NGTL System decreased by $13 million for the three months ended December 31, 2014 compared to the same period in 2013. This decrease was due to increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013, partially offset by a higher average investment base in 2014. Additionally, results for the three months ended December 31, 2013 reflect the annual impact of the 2013-2014 NGTL Settlement, which included an ROE of 10.10 per cent on deemed common equity of 40 per cent and annual fixed amounts for certain OM&A costs.

U.S. AND INTERNATIONAL PIPELINES

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

Comparable EBITDA for the U.S. and international pipelines increased by US$35 million for the three months ended December 31, 2014 compared to the same period in 2013. This was due to:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenues on ANR and Great Lakes.

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

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization decreased by $8 million for the three months ended December 31, 2014 compared to the same period in 2013 as fourth quarter 2013 included the annual impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. This settlement increased depreciation for 2013 and 2014. This year-over-year decrease compared to 2013 was partially offset by depreciation on the Tamazunchale Extension for the period in 2014.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

year ended December 31	Canadian Mainline[1]		NGTL System[2]		ANR[3]	
(unaudited)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Average investment base (millions of $)	**5,690**	5,841	**6,236**	5,938	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**1,645**	1,339	**3,891**	3,683	**1,588**	1,566
Average per day	**4.5**	3.7	**10.7**	10.1	**4.4**	4.3

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the year ended December 31, 2014 were 1,228 Bcf (2013 – 803 Bcf). Average per day was 3.4 Bcf (2013 – 2.2 Bcf).

2 Field receipt volumes for the NGTL System for the year ended December 31, 2014 were 3,888 Bcf (2013 – 3,680 Bcf). Average per day was 10.7 Bcf (2013 – 10.1 Bcf).

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

Liquids Pipelines

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

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable EBITDA	**288**	198	**1,059**	752
Comparable depreciation and amortization[1]	**(58)**	(38)	**(216)**	(149)
Comparable EBIT	**230**	160	**843**	603
Specific items	**—**	—	**—**	—
Segmented earnings	**230**	160	**843**	603

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

Liquids Pipelines segmented earnings increased by $70 million for the three months ended December 31, 2014 compared to the same period in 2013, and are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Keystone Pipeline System	**294**	200	**1,073**	766
Liquids Pipelines Business Development	**(6)**	(2)	**(14)**	(14)
Liquids Pipelines - comparable EBITDA	**288**	198	**1,059**	752
Comparable depreciation and amortization	**(58)**	(38)	**(216)**	(149)
Liquids Pipelines - comparable EBIT	**230**	160	**843**	603
Comparable EBIT denominated as follows:				
Canadian dollars	**58**	53	**215**	201
U.S. dollars	**153**	102	**570**	389
Foreign exchange impact	**19**	5	**58**	13
	230	160	**843**	603

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

Comparable EBITDA for the Keystone Pipeline System increased by $94 million for the three months ended December 31, 2014 compared to the same period in 2013. This increase was primarily due to:

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

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the Keystone Gulf Coast extension being placed in service.

Energy

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

(unaudited - millions of $)	three months ended December 31 2014	2013	year ended December 31 2014	2013
Comparable EBITDA	**385**	346	**1,348**	1,363
Comparable depreciation and amortization[1]	**(79)**	(74)	**(309)**	(294)
Comparable EBIT	**306**	272	**1,039**	1,069
Specific items (pre-tax):				
Cancarb gain on sale	**—**	—	**108**	—
Niska contract termination	**—**	—	**(43)**	—
Risk management activities	**(87)**	29	**(53)**	44
Segmented earnings	**219**	301	**1,051**	1,113

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

Energy segmented earnings decreased by $82 million for the three months ended December 31, 2014 compared to the same period in 2013.

Energy segmented earnings for the three months ended December 31, 2014 and 2013 included unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities (unaudited - millions of $, pre-tax)	three months ended December 31 2014	2013	year ended December 31 2014	2013
Canadian Power	**(11)**	(2)	**(11)**	(4)
U.S. Power	**(85)**	36	**(55)**	50
Natural Gas Storage	**9**	(5)	**13**	(2)
Total (losses)/gains from risk management activities	**(87)**	29	**(53)**	44

The quarterly variances in these unrealized gains and losses reflect the impact of changes in the forward natural gas and power prices and the volume of our position for these particular derivatives over a certain period of time; however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them part of our underlying operations and exclude them in our calculation of comparable EBIT.

The remainder of the Energy segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	**2013**	**2014**	**2013**
Comparable EBITDA	**385**	346	**1,348**	1,363
Comparable depreciation and amortization	**(79)**	(74)	**(309)**	(294)
Comparable EBIT	**306**	272	**1,039**	1,069

Canadian Power				
Western Power	**59**	51	**252**	355
Eastern Power[1]	**111**	91	**350**	322
Bruce Power	**115**	115	**314**	310
Canadian Power - comparable EBITDA[2]	**285**	257	**916**	987
Comparable depreciation and amortization	**(46)**	(43)	**(179)**	(172)
Canadian Power - comparable EBIT[2]	**239**	214	**737**	815
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**85**	65	**376**	323
Comparable depreciation and amortization	**(27)**	(27)	**(107)**	(107)
U.S. Power - comparable EBIT	**58**	38	**269**	216
Foreign exchange impact	**8**	2	**27**	7
U.S. Power - comparable EBIT (Cdn$)	**66**	40	**296**	223
Natural Gas Storage and other				
Natural Gas Storage and other - comparable EBITDA	**12**	27	**44**	63
Comparable depreciation and amortization	**(3)**	(3)	**(12)**	(12)
Natural Gas Storage and other - comparable EBIT	**9**	24	**32**	51
Business Development comparable EBITDA and EBIT	**(8)**	(6)	**(26)**	(20)
Energy - comparable EBIT[2]	**306**	272	**1,039**	1,069

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014 and one solar facility acquired at the end of December 2014.
2 Includes our share of equity income from our investments in ASTC Power Partnership, Portlands Energy and Bruce Power.

Comparable EBITDA for Energy increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the net effect of:

- higher earnings from Eastern Power due to higher contractual earnings at Bécancour, and incremental earnings from solar facilities acquired in December 2013 and the second half of 2014
- higher earnings from U.S. Power due to increased generation, higher sales to wholesale, commercial and industrial customers, and the impact of higher realized power and capacity prices
- lower earnings from Natural Gas Storage due to weaker realized natural gas storage spreads and lower volumes of third party sales.

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

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended December 31 2014	2013	year ended December 31 2014	2013
Revenue[1]				
Western Power	**189**	166	**736**	605
Eastern Power[2]	**106**	104	**428**	400
Other[3]	**28**	34	**85**	108
	323	304	**1,249**	1,113
Income from equity investments[4]	**3**	15	**45**	141
Commodity purchases resold	**(108)**	(94)	**(404)**	(283)
Plant operating costs and other	**(59)**	(85)	**(299)**	(298)
Exclude risk management activities[1]	**11**	2	**11**	4
Comparable EBITDA	**170**	142	**602**	677
Comparable depreciation and amortization	**(46)**	(43)	**(179)**	(172)
Comparable EBIT	**124**	99	**423**	505

Breakdown of comparable EBITDA				
Western Power	**59**	51	**252**	355
Eastern Power	**111**	91	**350**	322
Comparable EBITDA	**170**	142	**602**	677

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014 and one solar facility acquired at the end of December 2014.

3 Includes Revenue from the sale of unused natural gas transportation, excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.

4 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy. Equity income does not include earnings related to our risk management activities.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

	three months ended December 31		year ended December 31	
(unaudited)	**2014**	**2013**	**2014**	**2013**
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**660**	691	**2,517**	2,728
Eastern Power[1]	**644**	854	**3,080**	3,822
Purchased				
Sundance A & B and Sheerness PPAs and other[2]	**3,283**	2,771	**11,472**	8,223
Other purchases	**7**	12	**16**	13
	4,594	4,328	**17,085**	14,786
Sales				
Contracted				
Western Power	**3,004**	2,372	**10,484**	7,864
Eastern Power[1]	**644**	854	**3,080**	3,822
Spot				
Western Power	**946**	1,102	**3,521**	3,100
	4,594	4,328	**17,085**	14,786
Plant availability[3]				
Western Power[4]	**97%**	96%	**96%**	95%
Eastern Power[1,5]	**93%**	90%	**91%**	90%

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014 and one solar facility acquired at the end of December 2014.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Does not include facilities that provide power to TransCanada under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power increased by $8 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the net effect of:

- higher purchased volumes under the PPAs
- lower realized power prices.

Average spot market power prices in Alberta decreased by 35 per cent from $48/MWh to $31/MWh for the three months ended December 31, 2014 compared to the same period in 2013. Relatively soft price levels persisted as the Alberta power market was well supplied despite strong power demand growth. Realized prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

76 per cent of Western Power sales volumes were sold under contract in fourth quarter 2014 and 68 per cent in fourth quarter 2013.

Eastern Power

Comparable EBITDA for Eastern Power increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher Bécancour contractual earnings and incremental earnings from solar facilities acquired in December 2013 and in the second half of 2014.

BRUCE POWER

Our proportionate share

(unaudited - millions of $, unless noted otherwise)	three months ended December 31 2014	three months ended December 31 2013	year ended December 31 2014	year ended December 31 2013
Income from equity investments[1]				
Bruce A	**100**	70	**209**	202
Bruce B	**15**	45	**105**	108
	115	115	**314**	310
Comprised of:				
Revenues	**361**	342	**1,256**	1,258
Operating expenses	**(162)**	(145)	**(623)**	(618)
Depreciation and other	**(84)**	(82)	**(319)**	(330)
	115	115	**314**	310
Bruce Power - Other information				
Plant availability[2]				
Bruce A	**96%**	90%	**82%**	82%
Bruce B	**84%**	98%	**90%**	89%
Combined Bruce Power	**91%**	94%	**86%**	86%
Planned outage days				
Bruce A	**—**	—	**118**	123
Bruce B	**53**	—	**127**	140
Unplanned outage days				
Bruce A	**13**	18	**123**	63
Bruce B	**4**	7	**4**	20
Sales volumes (GWh)[1]				
Bruce A	**3,103**	2,916	**10,526**	10,458
Bruce B	**1,915**	2,228	**8,197**	8,010
	5,018	5,144	**18,723**	18,468
Realized sales price per MWh[3]				
Bruce A	**$72**	$71	**$72**	$70
Bruce B	**$58**	$54	**$56**	$54
Combined Bruce Power	**$65**	$62	**$63**	$62

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

Equity income from Bruce A increased by $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to higher generation levels and lower operating expenses. Fourth quarter 2014 results also include the impact of a deemed generation adjustment related to a prior quarter.

Equity income from Bruce B decreased $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

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

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

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price.

The OPA contract provides for payment if the Independent Electricity System Operator (IESO) reduces Bruce Power's generation to balance the supply of and demand for electricity and manage other operating conditions of the Ontario power grid. The amount of the generation reduction is considered "deemed generation", for which Bruce Power is paid the fixed price for Bruce A or the floor price or spot price for Bruce B as applicable.

U.S. POWER

	three months ended December 31		year ended December 31	
(unaudited - millions of US$)	**2014**	**2013**	**2014**	**2013**
Revenue				
Power[1]	**301**	371	**1,794**	1,587
Capacity	**84**	78	**362**	295
	385	449	**2,156**	1,882
Commodity purchases resold	**(270)**	(251)	**(1,297)**	(1,003)
Plant operating costs and other[2]	**(103)**	(100)	**(529)**	(509)
Exclude risk management activities[1]	**73**	(33)	**46**	(47)
Comparable EBITDA	**85**	65	**376**	323
Comparable depreciation and amortization	**(27)**	(27)	**(107)**	(107)
Comparable EBIT	**58**	38	**269**	216

1 The realized and unrealized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes the cost of fuel consumed in generation.

Sales volumes and plant availability

(unaudited)	three months ended December 31 2014	2013	year ended December 31 2014	2013
Physical sales volumes (GWh)				
Supply				
Generation	**1,580**	1,152	**7,742**	6,173
Purchased	**3,108**	2,259	**10,822**	9,001
	4,688	3,411	**18,564**	15,174
Plant availability[1,2]	**60%**	71%	**82%**	84%

1 The percentage of time the plant was available to generate power, regardless of whether it was running.
2 Plant availability for the three months ended December 31 was lower in 2014 than the same period in 2013 due to an unplanned outage at the Ravenswood facility.

Other Information	three months ended December 31 2014	2013	year ended December 31 2014	2013
Average Spot Power Prices (US$ per MWh)				
New England	**$ 41**	$ 57	**$ 65**	$ 57
New York	**$ 34**	$ 44	**$ 58**	$ 52
Average New York Zone J Spot Capacity Prices (US$ per KW-M)	**$ 12**	$ 12	**$ 14**	$ 11

Comparable EBITDA for U.S. Power increased US$20 million for the three months ended December 31, 2014 compared to the same period in 2013. The increase was the net effect of:

- higher margins and higher sales volumes to wholesale, commercial and industrial customers
- higher realized capacity prices primarily in New York
- higher generation at our hydro and Ravenswood facilities offset by lower realized power prices in New York and New England.

Wholesale electricity prices in New York and New England were lower for the three months ended December 31, 2014 compared to the same period in 2013 primarily due to warmer temperatures, decreased natural gas demand and lower natural gas price volatility. Average spot power prices for the three months ended December 31, 2014 in New England decreased approximately 29 per cent and in New York City spot power prices decreased approximately 21 per cent compared to the same period in 2013.

Average New York Zone J spot capacity prices for the three months ended December 31, 2014 were consistent with the same period in 2013 however, the impact of hedging activities resulted in higher realized capacity prices in 2014.

Physical sales volumes for the three months ended December 31, 2014 were higher than the same period in 2013. Generation volumes at our hydro and Ravenswood facilities increased due to higher precipitation and lower natural gas prices. Purchased volumes were also higher in the three months ended December 31, 2014 compared to 2013 due to increased sales to wholesale, commercial and industrial customers in both the New England and PJM markets.

As at December 31, 2014, approximately 3,700 GWh or 30 per cent of U.S. Power's planned generation was contracted for 2015, and 1,600 GWh or 14 per cent for 2016. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA for Natural Gas Storage and Other decreased $15 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower realized natural gas storage spreads and lower volumes of third party sales.

Other income statement items

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

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	2013	**2014**	2013
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	**(108)**	(123)	**(443)**	(495)
U.S. dollar-denominated	**(216)**	(205)	**(854)**	(766)
Foreign exchange	**(30)**	(7)	**(90)**	(20)
	(354)	(335)	**(1,387)**	(1,281)
Other interest and amortization expense	**(29)**	3	**(70)**	10
Capitalized interest	**60**	92	**259**	287
Comparable interest expense	**(323)**	(240)	**(1,198)**	(984)
Specific item:				
2013 NEB decision - 2012	**—**	—	**—**	(1)
Interest expense	**(323)**	(240)	**(1,198)**	(985)

Comparable interest expense for the three months ended December 31, 2014 was $83 million higher compared to the same period in 2013 due to the net effect of the following:

- higher interest on US$1.25 billion long term debt issued in February 2014
- lower interest on account of long term Canadian and U.S. dollar-denominated debt maturities
- higher foreign exchange on interest on U.S. dollar-denominated debt
- higher carrying charges to shippers in 2014 on the positive TSA balance for Canadian Mainline
- lower capitalized interest due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2014**	2013	**2014**	2013
Comparable interest income and other	**40**	10	**112**	42
Specific items (pre-tax):				
2013 NEB decision - 2012	**—**	—	**—**	1
Risk management activities	**(12)**	(9)	**(21)**	(9)
Interest income and other	**28**	1	**91**	34

Comparable interest income and other for the three months ended December 31, 2014 was $30 million higher compared to the same period in 2013 primarily as a result of increased AFUDC related to our rate-regulated projects, including Energy East Pipeline and our Mexico pipelines. This was partially offset by higher realized losses on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Comparable income tax expense	**(243)**	(198)	**(859)**	(662)
Specific items:				
Cancarb gain on sale	**—**	—	**(9)**	—
Niska contract termination	**—**	—	**11**	—
Gas Pacifico/ INNERGY gain on sale	**(1)**	—	**(1)**	—
2013 NEB decision - 2012	**—**	—	**—**	42
Part VI.I income tax adjustment	**—**	—	**—**	25
Risk management activities	**38**	(10)	**27**	(16)
Income tax expense	**(206)**	(208)	**(831)**	(611)

Comparable income tax expense increased $45 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to higher pre-tax earnings in 2014 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Net income attributable to non-controlling interests	**(43)**	(38)	**(153)**	(125)
Preferred share dividends	**(25)**	(19)	**(97)**	(74)

Net income attributable to non-controlling interests increased by $5 million for the three months ended December 31, 2014 compared to the same period in 2013 primarily due to the sale of the remaining 30 per cent interest in Bison to TC PipeLines, LP in October 2014, partially offset by the redemption of TCPL Series Y preferred shares in March 2014.

Preferred share dividends increased by $6 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the issuance of Series 9 preferred shares in January 2014.

Reconciliation of non-GAAP measures

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2014**	2013	**2014**	2013
EBITDA	**1,443**	1,320	**5,542**	4,958
Cancarb gain on sale	**—**	—	**(108)**	—
Niska contract termination	**—**	—	**43**	—
Gas Pacifico / INNERGY gain on sale	**(9)**	—	**(9)**	—
2013 NEB decision - 2012	**—**	—	**—**	(55)
Non-comparable risk management activities	**87**	(29)	**53**	(44)
Comparable EBITDA	**1,521**	1,291	**5,521**	4,859
Comparable depreciation and amortization	**(416)**	(396)	**(1,611)**	(1,472)
Comparable EBIT	**1,105**	895	**3,910**	3,387
Other income statement items				
Comparable interest expense	**(323)**	(240)	**(1,198)**	(984)
Comparable interest income and other	**40**	10	**112**	42
Comparable income tax expense	**(243)**	(198)	**(859)**	(662)
Net income attributable to non-controlling interests	**(43)**	(38)	**(153)**	(125)
Preferred share dividends	**(25)**	(19)	**(97)**	(74)
Comparable earnings	**511**	410	**1,715**	1,584
Specific items (net of tax):				
Cancarb gain on sale	**—**	—	**99**	—
Niska contract termination	**—**	—	**(32)**	—
Gas Pacifico/ INNERGY gain on sale	**8**	—	**8**	—
2013 NEB decision - 2012	**—**	—	**—**	84
Part VI.I income tax adjustment	**—**	—	**—**	25
Risk management activities[1]	**(61)**	10	**(47)**	19
Net income attributable to common shares	**458**	420	**1,743**	1,712
Comparable depreciation and amortization	**(416)**	(396)	**(1,611)**	(1,472)
Specific item:				
2013 NEB decision - 2012	**—**	—	**—**	(13)
Depreciation and amortization	**(416)**	(396)	**(1,611)**	(1,485)
Comparable interest expense	**(323)**	(240)	**(1,198)**	(984)
Specific item:				
2013 NEB decision - 2012	**—**	—	**—**	(1)
Interest expense	**(323)**	(240)	**(1,198)**	(985)
Comparable interest income and other	**40**	10	**112**	42
Specific items:				
2013 NEB decision - 2012	**—**	—	**—**	1
Risk management activities[1]	**(12)**	(9)	**(21)**	(9)
Interest income and other	**28**	1	**91**	34
Comparable income tax expense	**(243)**	(198)	**(859)**	(662)
Specific items:				
Cancarb gain on sale	**—**	—	**(9)**	—
Niska contract termination	**—**	—	**11**	—
Gas Pacifico/ INNERGY gain on sale	**(1)**	—	**(1)**	—
2013 NEB decision - 2012	**—**	—	**—**	42
Part VI.I income tax adjustment	**—**	—	**—**	25
Risk management activities[1]	**38**	(10)	**27**	(16)
Income tax expense	**(206)**	(208)	**(831)**	(611)

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2014	2013	2014	2013
Comparable earnings per common share	**$0.72**	$0.58	**$2.42**	$2.24
Specific items (net of tax):				
Cancarb gain on sale	**—**	—	**0.14**	—
Niska contract termination	**—**	—	**(0.04)**	—
Gas Pacifico/ INNERGY gain on sale	**0.01**	—	**0.01**	—
2013 NEB decision - 2012	**—**	—	**—**	0.12
Part VI.I income tax adjustment	**—**	—	**—**	0.04
Risk management activities[1]	**(0.08)**	0.01	**(0.07)**	0.02
Net income per common share	**$0.65**	$0.59	**$2.46**	$2.42

1 **Risk management activities** (unaudited - millions of $)	three months ended December 31		year ended December 31	
	2014	2013	2014	2013
Canadian Power	**(11)**	(2)	**(11)**	(4)
U.S. Power	**(85)**	36	**(55)**	50
Natural Gas Storage	**9**	(5)	**13**	(2)
Foreign exchange	**(12)**	(9)	**(21)**	(9)
Income tax attributable to risk management activities	**38**	(10)	**27**	(16)
Total (losses)/gains from risk management activities	**(61)**	10	**(47)**	19

Comparable EBITDA and EBIT by business segment

three months ended December 31, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**893**	**288**	**298**	**(36)**	**1,443**
Gas Pacifico/ INNERGY gain on sale	**(9)**	**—**	**—**	**—**	**(9)**
Non-comparable risk management activities	**—**	**—**	**87**	**—**	**87**
Comparable EBITDA	**884**	**288**	**385**	**(36)**	**1,521**
Comparable depreciation and amortization	**(272)**	**(58)**	**(79)**	**(7)**	**(416)**
Comparable EBIT	**612**	**230**	**306**	**(43)**	**1,105**

three months ended December 31, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	778	198	375	(31)	1,320
Non-comparable risk management activities	—	—	(29)	—	(29)
Comparable EBITDA	778	198	346	(31)	1,291
Comparable depreciation and amortization	(280)	(38)	(74)	(4)	(396)
Comparable EBIT	498	160	272	(35)	895

year ended December 31, 2014 (unaudited - millions of $)	**Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
EBITDA	**3,250**	**1,059**	**1,360**	**(127)**	**5,542**
Cancarb gain on sale	**—**	**—**	**(108)**	**—**	**(108)**
Niska contract termination	**—**	**—**	**43**	**—**	**43**
Gas Pacifico/ INNERGY gain on sale	**(9)**	**—**	**—**	**—**	**(9)**
Non-comparable risk management activities	**—**	**—**	**53**	**—**	**53**
Comparable EBITDA	**3,241**	**1,059**	**1,348**	**(127)**	**5,521**
Comparable depreciation and amortization	**(1,063)**	**(216)**	**(309)**	**(23)**	**(1,611)**
Comparable EBIT	**2,178**	**843**	**1,039**	**(150)**	**3,910**

year ended December 31, 2013 (unaudited - millions of $)	**Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
EBITDA	2,907	752	1,407	(108)	4,958
2013 NEB decision - 2012	(55)	—	—	—	(55)
Non-comparable risk management activities	—	—	(44)	—	(44)
Comparable EBITDA	2,852	752	1,363	(108)	4,859
Comparable depreciation and amortization	(1,013)	(149)	(294)	(16)	(1,472)
Comparable EBIT	1,839	603	1,069	(124)	3,387

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended December 31		year ended December 31	
	2014	**2013**	**2014**	**2013**
Revenues				
Natural Gas Pipelines	**1,399**	1,226	**4,913**	4,497
Liquids Pipelines	**435**	294	**1,547**	1,124
Energy	**782**	812	**3,725**	3,176
	2,616	2,332	**10,185**	8,797
Income from Equity Investments	**160**	174	**522**	597
Operating and Other Expenses				
Plant operating costs and other	**810**	735	**2,973**	2,674
Commodity purchases resold	**414**	359	**1,836**	1,317
Property taxes	**118**	92	**473**	445
Depreciation and amortization	**416**	396	**1,611**	1,485
	1,758	1,582	**6,893**	5,921
Gain on Sale of Assets	**9**	—	**117**	—
Financial Charges/(Income)				
Interest expense	**323**	240	**1,198**	985
Interest income and other	**(28)**	(1)	**(91)**	(34)
	295	239	**1,107**	951
Income before Income Taxes	**732**	685	**2,824**	2,522
Income Tax Expense				
Current	**41**	3	**145**	43
Deferred	**165**	205	**686**	568
	206	208	**831**	611
Net Income	**526**	477	**1,993**	1,911
Net Income Attributable to Non-Controlling Interests	**43**	38	**153**	125
Net Income Attributable to Controlling Interests	**483**	439	**1,840**	1,786
Preferred Share Dividends	**25**	19	**97**	74
Net Income Attributable to Common Shares	**458**	420	**1,743**	1,712
Net Income per Common Share				
Basic and Diluted	**$0.65**	$0.59	**$2.46**	$2.42
Dividends Declared per Common Share	**$0.48**	$0.46	**$1.92**	$1.84
Weighted Average Number of Common Shares (millions)				
Basic	**709**	707	**708**	707
Diluted	**710**	708	**710**	708

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended December 31 2014	three months ended December 31 2013	year ended December 31 2014	year ended December 31 2013
Cash Generated from Operations				
Net income	**526**	477	**1,993**	1,911
Depreciation and amortization	**416**	396	**1,611**	1,485
Deferred income taxes	**165**	205	**686**	568
Income from equity investments	**(160)**	(174)	**(522)**	(597)
Distributed earnings received from equity investments	**164**	178	**579**	605
Employee post-retirement benefits expense, net of funding	**9**	17	**37**	50
Gain on sale of assets	**(9)**	—	**(117)**	—
Equity AFUDC	**(36)**	(5)	**(95)**	(19)
Unrealized losses/(gains) on financial instruments	**99**	(20)	**74**	(35)
Other	**4**	9	**22**	32
Decrease/(increase) in operating working capital	**12**	(74)	**(189)**	(326)
Net cash provided by operations	**1,190**	1,009	**4,079**	3,674
Investing Activities				
Capital expenditures	**(1,128)**	(1,311)	**(3,550)**	(4,264)
Capital projects under development	**(330)**	(297)	**(807)**	(488)
Equity investments	**(61)**	(62)	**(256)**	(163)
Acquisitions, net of cash acquired	**(60)**	(62)	**(241)**	(216)
Proceeds from sale of assets, net of transaction costs	**9**	—	**196**	—
Deferred amounts and other	**(90)**	164	**514**	11
Net cash used in investing activities	**(1,660)**	(1,568)	**(4,144)**	(5,120)
Financing Activities				
Dividends on common shares	**(340)**	(324)	**(1,345)**	(1,285)
Dividends on preferred shares	**(25)**	(20)	**(94)**	(71)
Distributions paid to non-controlling interests	**(44)**	(52)	**(178)**	(166)
Notes payable issued/(repaid), net	**689**	126	**544**	(492)
Long-term debt issued, net of issue costs	**23**	1,336	**1,403**	4,253
Repayment of long-term debt	**(49)**	(56)	**(1,069)**	(1,286)
Common shares issued	**4**	13	**47**	72
Preferred shares issued, net of issue costs	**—**	—	**440**	585
Partnership units of subsidiary issued, net of issue costs	**—**	—	**79**	384
Preferred shares of subsidiary redeemed	**—**	(200)	**(200)**	(200)
Net cash provided by/(used in) financing activities	**258**	823	**(373)**	1,794
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**3**	18	**—**	28
(Decrease)/ Increase in Cash and Cash Equivalents	**(209)**	282	**(438)**	376
Cash and Cash Equivalents				
Beginning of period	**698**	645	**927**	551
Cash and Cash Equivalents				
End of period	**489**	927	**489**	927

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		December 31, 2014	December 31, 2013
ASSETS			
Current Assets			
Cash and cash equivalents		**489**	927
Accounts receivable		**1,313**	1,122
Inventories		**292**	251
Other		**1,446**	847
		3,540	3,147
Plant, Property and Equipment	net of accumulated depreciation of $19,563 and $17,851, respectively	**41,774**	37,606
Equity Investments		**5,598**	5,759
Regulatory Assets		**1,297**	1,735
Goodwill		**4,034**	3,696
Intangible and Other Assets		**2,704**	1,955
		58,947	53,898
LIABILITIES			
Current Liabilities			
Notes payable		**2,467**	1,842
Accounts payable and other		**2,896**	2,155
Accrued interest		**424**	388
Current portion of long-term debt		**1,797**	973
		7,584	5,358
Regulatory Liabilities		**263**	229
Other Long-Term Liabilities		**1,052**	656
Deferred Income Tax Liabilities		**5,275**	4,564
Long-Term Debt		**22,960**	21,892
Junior Subordinated Notes		**1,160**	1,063
		38,294	33,762
EQUITY			
Common shares, no par value		**12,202**	12,149
Issued and outstanding:	December 31, 2014 - 709 million shares		
	December 31, 2013 - 707 million shares		
Preferred shares		**2,255**	1,813
Additional paid-in capital		**370**	401
Retained earnings		**5,478**	5,096
Accumulated other comprehensive loss		**(1,235)**	(934)
Controlling Interests		**19,070**	18,525
Non-controlling interests		**1,583**	1,611
		20,653	20,136
		58,947	53,898

Segmented information

three months ended December 31	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Revenues	**1,399**	1,226	**435**	294	**782**	812	**—**	—	**2,616**	2,332
Income from Equity Investments	**39**	40	**—**	—	**121**	134	**—**	—	**160**	174
Plant operating costs and other	**(471)**	(423)	**(133)**	(86)	**(170)**	(195)	**(36)**	(31)	**(810)**	(735)
Commodity purchases resold	**—**	—	**—**	—	**(414)**	(359)	**—**	—	**(414)**	(359)
Property taxes	**(83)**	(65)	**(14)**	(10)	**(21)**	(17)	**—**	—	**(118)**	(92)
Depreciation and amortization	**(272)**	(280)	**(58)**	(38)	**(79)**	(74)	**(7)**	(4)	**(416)**	(396)
Gain on Sale of Assets	**9**	—	**—**	—	**—**	—	**—**	—	**9**	—
Segmented earnings	**621**	498	**230**	160	**219**	301	**(43)**	(35)	**1,027**	924
Interest expense									**(323)**	(240)
Interest income and other									**28**	1
Income before income taxes									**732**	685
Income tax expense									**(206)**	(208)
Net income									**526**	477
Net Income Attributable to Non-Controlling Interests									**(43)**	(38)
Net Income Attributable to Controlling Interests									**483**	439
Preferred Share Dividends									**(25)**	(19)
Net Income Attributable to Common Shares									**458**	420

year ended December 31	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Revenues	**4,913**	4,497	**1,547**	1,124	**3,725**	3,176	**—**	—	**10,185**	8,797
Income from Equity Investments	**163**	145	**—**	—	**359**	452	**—**	—	**522**	597
Plant operating costs and other	**(1,501)**	(1,405)	**(426)**	(328)	**(919)**	(833)	**(127)**	(108)	**(2,973)**	(2,674)
Commodity purchases resold	**—**	—	**—**	—	**(1,836)**	(1,317)	**—**	—	**(1,836)**	(1,317)
Property taxes	**(334)**	(329)	**(62)**	(44)	**(77)**	(72)	**—**	—	**(473)**	(445)
Depreciation and amortization	**(1,063)**	(1,027)	**(216)**	(149)	**(309)**	(293)	**(23)**	(16)	**(1,611)**	(1,485)
Gain on Sale of Assets	**9**	—	**—**	—	**108**	—	**—**	—	**117**	—
Segmented earnings	**2,187**	1,881	**843**	603	**1,051**	1,113	**(150)**	(124)	**3,931**	3,473
Interest expense									**(1,198)**	(985)
Interest income and other									**91**	34
Income before Income Taxes									**2,824**	2,522
Income Tax Expense									**(831)**	(611)
Net income									**1,993**	1,911
Net Income Attributable to Non-Controlling Interests									**(153)**	(125)
Net Income Attributable to Controlling Interests									**1,840**	1,786
Preferred Share Dividends									**(97)**	(74)
Net Income Attributable to Common Shares									**1,743**	1,712

TOTAL ASSETS

(unaudited - millions of Canadian $)	December 31, 2014	December 31, 2013
Natural Gas Pipelines	**27,103**	25,165
Liquids Pipelines	**16,116**	13,253
Energy	**14,197**	13,747
Corporate	**1,531**	1,733
	58,947	53,898