NewsRelease

TransCanada
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TransCanada Reports 2012 Comparable Earnings of $1.3 Billion Increases Common Share Dividend by Five Per Cent

Calgary, Alberta – **February 12, 2013** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for fourth quarter 2012 of $318 million or $0.45 per share. For the year ended December 31, 2012, comparable earnings were $1.3 billion or $1.89 per share. TransCanada's Board of Directors also declared a quarterly dividend of $0.46 per common share for the quarter ending March 31, 2013, equivalent to $1.84 per common share on an annualized basis, an increase of five per cent. This is the thirteenth consecutive year the Board of Directors has raised the dividend.

"TransCanada's diverse set of high-quality critical energy infrastructure assets performed relatively well over the course of 2012," said Russ Girling, TransCanada's president and chief executive officer. "While the majority of our assets continued to generate stable and predictable earnings and cash flow, plant outages at Bruce Power and Sundance A along with a lower contribution from certain natural gas pipelines did adversely affect our financial results.

"In 2012, we made significant progress on a number of initiatives to improve earnings and position our Company for continued growth," added Girling. "We commenced construction on the Gulf Coast Project, advanced Keystone XL, received positive decisions related to Sundance A and Ravenswood, and placed $3.4 billion of new assets into service. The restart of Bruce Power Units 1 and 2, the return to service of Sundance A in fall 2013, and the start up of other natural gas pipeline and energy projects are expected to have a positive impact on earnings and cash flow in 2013. Looking forward, TransCanada is well positioned to grow sustainable earnings, cash flow and dividends as we complete our current capital program, benefit from an anticipated recovery in natural gas and power prices and execute on our significant portfolio of secured new growth opportunities."

Over the next three years, subject to required approvals, TransCanada expects to complete $12 billion of projects that are currently in advanced stages of development. They include the Gulf Coast Project, Keystone XL, the Keystone Hardisty Terminal, the initial phase of the Grand Rapids Pipeline, the Tamazunchale extension, the acquisition of nine Ontario Solar projects, and the ongoing expansion of the Alberta System.

During the course of 2012 and early 2013, the Company also commercially secured an additional $13 billion of long-life, contracted energy infrastructure projects that are expected to be placed into service in 2016 and beyond. They include the Coastal GasLink and Prince Rupert Gas Transmission projects that would move natural gas to Canada's West Coast for liquefaction and shipment to Asian markets, the Topolobampo and Mazatlan Gas Pipeline projects in Mexico, completion of the Grand Rapids and Northern Courier oil pipeline projects in Northern Alberta, and the Napanee Generating Station in Eastern Ontario. TransCanada expects these projects to generate predictable, sustained earnings and cash flow.

Fourth Quarter and Year-End Highlights

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

- Fourth quarter financial results
    - Comparable earnings of $318 million or $0.45 per share
    - Net income attributable to common shares of $306 million or $0.43 per share
    - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.1 billion

  - Funds generated from operations of $818 million
- For the year ended December 31, 2012
  - Comparable earnings of $1.3 billion or $1.89 per share
  - Net income attributable to common shares of $1.3 billion or $1.84 per share
  - Comparable EBITDA of $4.2 billion
  - Funds generated from operations of $3.3 billion
- Announced an increase in the quarterly common share dividend of five per cent to $0.46 per share for the quarter ending March 31, 2013
- Selected to develop a proposed $5 billion pipeline that would transport natural gas to the recently announced Pacific Northwest LNG export facility near Prince Rupert, British Columbia (B.C.). An additional $1 to $1.5 billion of Alberta System expansions would be required as part of the project
- Awarded US$1.4 billion in contracts to build the Topolobampo and Mazatlan natural gas pipelines in Mexico
- Signed a 20-year Power Purchase Arrangement (PPA) with the Ontario Power Authority (OPA) to develop the $1 billion Napanee natural gas-fired power plant in Eastern Ontario
- Bruce Power completed the refurbishment of Units 1 and 2 and placed the units into commercial service on October 22 and October 31, respectively
- Continued to advance construction on the US$2.3 billion Gulf Coast Project that will transport crude oil from Cushing, Oklahoma to the U.S. Gulf Coast
- Governor of Nebraska approved the re-route of Keystone XL through the state

Comparable earnings for fourth quarter 2012 were $318 million or $0.45 per share compared to $365 million or $0.52 per share for the same period in 2011. The decrease was primarily due to lower earnings contributions from Western Power, Bruce Power and certain natural gas pipelines including the Canadian Mainline, ANR and Great Lakes.

Comparable earnings for the year ended December 31, 2012 were $1.3 billion or $1.89 per share compared to $1.6 billion or $2.22 per share in 2011. Incremental earnings from Keystone and recently commissioned assets were more than offset by lower contributions from Western Power, Bruce Power, U.S. Power and certain natural gas pipelines including the Canadian Mainline, ANR and Great Lakes.

Net income attributable to common shares for fourth quarter 2012 was $306 million or $0.43 per share compared to $376 million or $0.53 per share in fourth quarter 2011. For the year ended December 31, 2012, net income attributable to common shares was $1.3 billion or $1.84 per share compared to $1.5 billion or $2.17 per share in 2011.

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

Oil Pipelines:

- *Gulf Coast Project*: In August 2012, TransCanada started construction on the US$2.3 billion Gulf Coast Project. The 36-inch pipeline, which will extend from Cushing, Oklahoma to the U.S. Gulf Coast, is expected to have an initial capacity of up to 700,000 barrels per day (bbl/d) with an ultimate capacity of 830,000 bbl/d. Construction of the pipeline is approximately 45 per cent complete and is expected to be in service in late 2013.

- *Keystone XL:* On January 4, 2013, the Nebraska Department of Environmental Quality issued its final evaluation report on the proposed re-route of Keystone XL to the Governor of Nebraska. The report noted that the new route avoids the Nebraska Sandhills, and that construction and operation of the pipeline is expected to have minimal environmental impacts in Nebraska. On January 22, 2013, the Governor of Nebraska approved the re-route through the state. The new route now becomes part of the project's Presidential Permit application with the U.S. Department of State, which was filed on May 4, 2012.

Subject to regulatory approvals, TransCanada expects Keystone XL to be in service in late 2014 or early 2015. The approximate cost of the 36-inch, 830,000 bbl/d line is US$5.3 billion. As of December 31, 2012, US$1.8 billion has been invested in the project.

- *Grand Rapids Pipeline:* In October 2012, TransCanada announced that it entered into binding agreements with Phoenix Energy Holdings Limited (Phoenix) to develop the Grand Rapids Pipeline in Northern Alberta. TransCanada and Phoenix will each own 50 per cent of the proposed $3 billion pipeline project that includes both a crude oil and a diluent line to transport volumes approximately 500 kilometres (km) (300 miles) between the producing area northwest of Fort McMurray and the Edmonton / Heartland region. The pipeline will be the first to serve the growing oil sands region west of the Athabasca River. TransCanada will be the operator and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the system.

  The Grand Rapids Pipeline system, subject to regulatory approvals, is expected to be placed into service in multiple stages, with initial crude oil service by mid-2015. Once completed in 2017, the full system will have the capacity to move up to 900,000 bbl/d of crude oil and 330,000 bbl/d of diluent.

- *Canadian Mainline Conversion:* TransCanada has determined a conversion of a portion of the Canadian Mainline natural gas pipeline system to crude oil service is both technically and economically feasible. Through a combination of converted natural gas pipeline and new construction, the proposed pipeline would deliver crude oil between Hardisty, Alberta and markets in Eastern Canada. The Company has begun soliciting input from stakeholders and prospective shippers to determine market acceptance of the proposed project.

Natural Gas Pipelines:

- *Alberta System:* During 2012, TransCanada continued to expand its Alberta System by completing and placing into service pipeline projects totalling approximately $650 million. This work included completion of the Horn River project in May, which extended the Alberta System into the Horn River shale play in Northeast B.C.

  In 2012, the National Energy Board (NEB) approved approximately $640 million of 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 of 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.

  TransCanada proposes to extend the Alberta System in Northeast B.C. to connect to both the recently announced Prince Rupert Gas Transmission Project and to incremental North Montney gas supply. This new infrastructure would allow the Pacific Northwest LNG facility to access both the abundant North Montney natural gas supply and other Western Canada Sedimentary Basin supply through the extensive Alberta System. Initial capital cost estimates are $1 to $1.5 billion, with an in service date of late 2015 targeted for a large portion of this infrastructure.

- *Prince Rupert Gas Transmission Project:* In January 2013, TransCanada was selected by Progress Energy Canada Ltd. (Progress), to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission pipeline. 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. Progress and TransCanada expect to finalize definitive agreements in early 2013, subject to approvals by their respective Boards of Directors. The project is expected to be placed in service by the end of 2018, subject to regulatory approvals and a final investment decision to be made by Progress.

- *Topolobampo Pipeline Project:* In November 2012, Mexico's Comisión Federal de Electricidad (CFE) awarded TransCanada the Topolobampo pipeline project, from Chihuahua to Topolobampo, Mexico. The project, which is supported by a 25-year contract with CFE, is a 530 km (329 mile) natural gas pipeline with a capacity of 670 million cubic feet per day (MMcf/d). The project is expected to cost approximately US$1 billion and be in service in mid-2016.

- *Mazatlan Pipeline Project*: In November 2012, the CFE also awarded TransCanada the Mazatlan pipeline project, which will extend from El Oro to Mazatlan, Mexico and interconnect with the Topolobampo pipeline. The project consists of a 413 km (257 mile) natural gas pipeline with a capacity of 200 MMcf/d that is supported by a 25-year contract with CFE. It is expected to cost approximately US$400 million and be in service by fourth quarter 2016.

- *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 expected in late first quarter or early second quarter 2013.

  In May 2012, TransCanada received NEB approval to build new pipeline facilities to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. On November 1, 2012, a portion of these facilities began transporting natural gas.

Energy:

- *Bruce Power:* In late 2012, Bruce Power completed the multi-year refurbishment of Units 1 and 2 by placing them into commercial service on October 22 and October 31, respectively. Both units 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.

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

  In 2013, the overall plant availability is expected to be approximately 90 per cent for Bruce A and in the high 80 per cent range for Bruce B. Following the full return to service of both Units

1 and 2, Bruce Power will be capable of producing 6,200 megawatts (MW) of emission-free power for the province of Ontario.

- *Napanee Generating Station:* On December 17, 2012, TransCanada signed a 20-year contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant. The facility will be located at Ontario Power Generation's Lennox Generating Station in the town of Greater Napanee in Eastern Ontario. The Napanee Generating Station will replace the facility that was planned and subsequently cancelled in the community of Oakville. The Company has been reimbursed for $250 million of costs, primarily related to natural gas turbines that were purchased for the Oakville project which will be deployed at Napanee. The Company will further invest approximately $1 billion in the Napanee facility.

- *CrossAlta Acquisition:* In December 2012, the Company 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 $214 million, net of cash acquired. TransCanada now owns 100 per cent of these operations. This acquisition added 27 billion cubic feet (Bcf) of working gas storage capacity to the Company's existing portfolio in Alberta.

- *Cartier Wind:* The 111 MW second phase of Gros-Morne was placed into service on November 6, 2012. This marks the completion of the 590 MW Cartier Wind project in Québec, the largest wind development in Canada. All of the power produced by Cartier Wind is sold under 20-year PPAs to Hydro-Québec.

- *Ravenswood:* In 2011, TC Ravenswood, LLC jointly filed two formal complaints with the Federal Energy Regulatory Commission (FERC) challenging how the New York Independent System Operator (NYISO) applied its buy-side mitigation rules affecting bidding criteria associated with two new power plants that began service in the New York Zone J market 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 NYISO 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.

Corporate:

- The Board of Directors of TransCanada declared a quarterly dividend of $0.46 per share for the quarter ending March 31, 2013 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.84 per common share on an annual basis and represents a five per cent increase over the previous amount.

- In January 2013, TransCanada issued US$750 million of senior notes maturing on January 15, 2016, bearing interest at an annual rate of 0.75 per cent. The net proceeds of the offering were used to reduce short-term indebtedness and for general corporate purposes.

- As previously disclosed, TransCanada adopted U.S. generally accepted accounting principles (U.S. GAAP) effective January 1, 2012. Accordingly, the 2012 financial information, along with comparative financial information for 2011, has been prepared in accordance with U.S. GAAP.

Teleconference – Audio and Slide Presentation:

TransCanada will hold a teleconference and webcast on Tuesday, February 12, 2013 to discuss its fourth quarter 2012 financial results. Russ Girling, TransCanada's 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. (MST) / 3:00 p.m. (EST).

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1793 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 11:59 PM (EST) February 19, 2013. Please call 905.694.9451 or 800.408.3053 (North America only) and enter pass code 6260206.

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.

TransCanada Media Enquiries:
Shawn Howard/Grady Semmens
403.920.7859 or 800.608.7859

TransCanada Investor & Analyst Enquiries:
David Moneta/Lee Evans
403.920.7911 or 800.361.6522

Fourth Quarter 2012 Financial Highlights

Operating Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2012**	2011	Year end ended December 31 **2012**	2011
Revenues	**2,089**	2,015	**8,007**	7,839
Comparable EBITDA[1]	**1,052**	1,120	**4,245**	4,544
Net Income Attributable to Common Shares	**306**	376	**1,299**	1,526
Comparable Earnings[1]	**318**	365	**1,330**	1,559
Cash Flows				
Funds generated from operations[1]	**818**	837	**3,284**	3,451
Decrease in operating working capital	**207**	90	**287**	235
Net cash provided by operations	**1,025**	927	**3,571**	3,686
Capital Expenditures	**1,040**	920	**2,595**	2,513

Common Share Statistics

(unaudited)	Three months ended December 31 **2012**	2011	Year end ended December 31 **2012**	2011
Net Income per Share - Basic	**$0.43**	$0.53	**$1.84**	$2.17
Comparable Earnings per Share[1]	**$0.45**	$0.52	**$1.89**	$2.22
Dividends Declared per Common Share	**$0.44**	$0.42	**$1.76**	$1.68
Basic Common Shares Outstanding (millions)				
Average for the period	**705**	703	**705**	702
End of period	**705**	703	**705**	703

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA, Comparable Earnings, Funds Generated from Operations and Comparable Earnings per Share.

Forward-Looking Information

TransCanada Corporation (TransCanada or the Company) discloses forward-looking information to help current and potential investors understand management's assessment of the Company's future plans and financial outlook, and future prospects overall.

Statements that are forward-looking are based on what the Company knows and expects 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
- financial and operational performance, including the performance of TransCanada's subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- expected costs for planned projects, including projects under 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 various assumptions, risks or uncertainties related to TransCanada's business or events that happen after the date of this news release.

TransCanada's forward-looking information is based on the following key assumptions, risks and uncertainties, among other things:

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 the Company's 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
- TransCanada's ability to successfully implement strategic initiatives
- whether these strategic initiatives will yield the expected benefits
- the operating performance of the Company's pipeline and energy assets
- amount of capacity sold and rates achieved in our U.S. pipeline business
- the availability and price of energy commodities
- the amount of capacity payments and revenues received from TransCanada's energy business

- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of 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 currency exchange rates
- weather
- technological developments
- economic conditions in North America as well as globally.

More information about these and other factors is available in reports TransCanada has filed with Canadian securities regulators and the U.S. Securities and Exchange Commission.

Readers should not put undue reliance on forward-looking information. TransCanada does not update forward-looking statements based on new information or future events, unless required to by law.

Non-GAAP Measures

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this news release. These measures do not have any standardized meaning as prescribed by U.S. generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and are unlikely to be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBITDA includes income from equity investments. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends. EBIT includes income from equity investments.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to 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. These non-GAAP measures are calculated on a consistent basis from period to period. The specific items for which such measures are adjusted in each applicable period may only be relevant in certain periods and are disclosed in the Reconciliation of Non-GAAP Measures table in this news release.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing derivatives. The risk management activities which TransCanada excludes from Comparable Earnings provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each year. The unrealized gains or losses from changes in the fair value of these derivative contracts are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The Reconciliation of Non-GAAP Measures table in this news release presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the period.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period.

Reconciliation of Non-GAAP Measures

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	**2012**	2011
Comparable EBITDA	**1,052**	1,120
Depreciation and amortization	**(343)**	(341)
Comparable EBIT	**709**	779
Other income statement items		
Comparable interest expense	**(246)**	(251)
Comparable interest income and other	**20**	8
Comparable income taxes	**(123)**	(124)
Net income attributable to non-controlling interests	**(28)**	(33)
Preferred share dividends	**(14)**	(14)
Comparable earnings	**318**	365
Specific item (net of tax):		
Risk management activities[1]	**(12)**	11
Net income attributable to common shares	**306**	376
Comparable interest expense	**(246)**	(251)
Specific item:		
Risk management activities	**-**	-
Interest expense	**(246)**	(251)
Comparable interest income and other	**20**	8
Specific item:		
Risk management activities[1]	**(5)**	35
Interest income and other	**15**	43
Comparable income taxes	**(123)**	(124)
Specific item:		
Risk management activities[1]	**5**	(2)
Income taxes expense	**(118)**	(126)
Comparable earnings per common share	**$0.45**	$0.52
Specific item (net of tax):		
Risk management activities[1]	**(0.02)**	0.01
Net income per common share	**$0.43**	$0.53

Three months ended December 31 *(unaudited)(millions of dollars)*	**2012**	2011
Funds generated from operations	**818**	837
Decrease in operating working capital	**207**	90
Net cash provided by operations	**1,025**	927

EBITDA and EBIT by Business Segment

Three months ended December 31, 2012 *(unaudited)* *(millions of dollars)*	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 dollars)*	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

(1)

Three months ended December 31 *(unaudited)(millions of dollars)*	**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

Reconciliation of Non-GAAP Measures

Year ended December 31 *(unaudited)(millions of dollars except per share amounts)*	**2012**	2011
Comparable EBITDA	**4,245**	4,544
Depreciation and amortization	**(1,375)**	(1,328)
Comparable EBIT	**2,870**	3,216
Other income statement items		
Comparable interest expense	**(976)**	(939)
Comparable interest income and other	**86**	60
Comparable income taxes	**(477)**	(594)
Net income attributable to non-controlling interests	**(118)**	(129)
Preferred share dividends	**(55)**	(55)
Comparable earnings	**1,330**	1,559
Specific items (net of tax):		
Sundance A PPA arbitration decision	**(15)**	-
Risk management activities(1)	**(16)**	(33)
Net income attributable to common shares	**1,299**	1,526
Comparable interest expense	**(976)**	(939)
Specific item:		
Risk management activities(1)	**-**	2
Interest expense	**(976)**	(937)
Comparable interest income and other	**86**	60
Specific item:		
Risk management activities(1)	**(1)**	(5)
Interest income and other	**85**	55
Comparable income taxes	**(477)**	(594)
Specific item:		
Sundance A PPA arbitration decision	**5**	-
Risk management activities(1)	**6**	19
Income taxes expense	**(466)**	(575)
Comparable earnings per common share	**$1.89**	$2.22
Specific items (net of tax):		
Sundance A PPA arbitration decision	**(0.02)**	-
Risk management activities(1)	**(0.03)**	(0.05)
Net income per common share	**$1.84**	$2.17

Year ended December 31 *(unaudited)(millions of dollars)*	**2012**	2011
Funds generated from operations	**3,284**	3,451
Decrease in operating working capital	**287**	235
Net cash provided by operations	**3,571**	3,686

EBITDA and EBIT by Business Segment

Year ended December 31, 2012 *(unaudited)* *(millions of dollars)*	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 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
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

(1)

Year ended December 31 *(unaudited)(millions of dollars)*	**2012**	2011
Risk Management Activities Gains/(Losses):		
Canadian Power	**4**	1
U.S. Power	**(1)**	(48)
Natural Gas Storage	**(24)**	(2)
Interest rate	**-**	2
Foreign exchange	**(1)**	(5)
Income taxes attributable to risk management activities	**6**	19
Risk Management Activities	**(16)**	(33)

Consolidated Results of Operations

Fourth Quarter Results

Comparable Earnings in fourth quarter 2012 were $318 million or $0.45 per share compared to $365 million or $0.52 per share for the same period in 2011. Comparable Earnings excluded net unrealized after-tax losses of $12 million ($17 million pre-tax) (2011 – gains of $11 million after tax; ($13 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings decreased $47 million or $0.07 per share in fourth quarter 2012 compared to the same period in 2011 and reflected 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 Power Purchase Arrangement (PPA) force majeure as well as lower equity earnings from ASTC Power Partnership resulting from an unfavorable 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;

- decreased Comparable Interest Expense due to capitalized interest for the Gulf Coast Project partially offset by reduced capitalized interest related to our investment in Bruce Power as a result of refurbished Bruce A Units 1 and 2 being placed in service; and

- increased Comparable Interest Income and Other due to higher realized gains in 2012 compared to losses in 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Annual Results

Comparable Earnings in 2012 were $1,330 million or $1.89 per share compared to $1,559 million or $2.22 per share for 2011. Comparable Earnings in 2012 excluded net unrealized after-tax losses of $16 million ($22 million pre-tax) (2011 – losses of $33 million after tax ($52 million pre-tax)) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in 2012 also excluded a negative after-tax charge of $15 million ($20 million pre-tax) following the July 2012 Sundance A PPA arbitration decision that was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011.

Comparable Earnings decreased $229 million or $0.33 per share in 2012 compared to 2011 and reflected 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 which primarily reflected lower revenue resulting from lower rates and uncontracted capacity on Great Lakes, as well as lower transportation and storage revenues, lower incidental commodity sales and higher operating costs on ANR, partially offset by incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011;

- increased Oil Pipelines Comparable EBIT which reflected higher Keystone Pipeline System revenues primarily due to higher contracted volumes and 12 months of earnings in 2012 compared to 11 months in 2011, partially offset by higher business development activity and related costs;

- decreased Energy Comparable EBIT primarily as a result of the Sundance A PPA force majeure, decreased Equity Income from Bruce Power due to increased outage days and lower earnings from U.S. Power due to lower realized prices, higher load serving costs and reduced water flows at U.S. hydro facilities. These decreases were partially offset by incremental earnings from Cartier Wind and Coolidge;

- increased Comparable Interest Expense due to incremental interest expense on new debt issues, net of maturities, in 2012 and 2011 and the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest;

- increased Comparable Interest Income and Other due to higher realized gains in 2012 on derivatives used to manage the Company's exposure to Foreign Exchange rate fluctuations on U.S.

dollar-denominated income and gains in 2012 compared to losses in 2011 on translation of foreign denominated working capital balances; and

- decreased Comparable Income Taxes primarily due to lower pre-tax earnings in 2012 compared to 2011.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in the Canadian-U.S. foreign exchange rate. The average exchange rate to convert a U.S. dollar to a Canadian dollar for fourth quarter 2012 and year ended December 31, 2012 was 0.99 and 1.00, respectively (2011 – 1.02 and 0.99, respectively).

Summary of Significant U.S. Dollar-Denominated Amounts

(unaudited)	Three months ended December 31		Year ended December 31	
(millions of U.S. dollars, pre-tax)	**2012**	2011	**2012**	2011
U.S. and International Natural Gas Pipelines Comparable EBIT[1]	**159**	183	**660**	761
U.S. Oil Pipelines Comparable EBIT[1]	**94**	91	**363**	301
U.S. Power Comparable EBIT[1]	**17**	4	**88**	164
Interest on U.S. dollar-denominated long-term debt	**(186)**	(185)	**(740)**	(734)
Capitalized interest on U.S. capital expenditures	**43**	23	**124**	116
U.S. non-controlling interests and other	**(52)**	(49)	**(192)**	(192)
	75	67	**303**	416

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBIT.

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.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Canadian Natural Gas Pipelines				
Canadian Mainline	**250**	262	**994**	1,058
Alberta System	**195**	185	**749**	742
Foothills	**30**	31	**120**	127
Other (TQM[1], Ventures LP)	**7**	8	**29**	34
Canadian Natural Gas Pipelines Comparable EBITDA[2]	**482**	486	**1,892**	1,961
Depreciation and amortization[3]	**(182)**	(178)	**(715)**	(711)
Canadian Natural Gas Pipelines Comparable EBIT[2]	**300**	308	**1,177**	1,250
U.S. and International Natural Gas Pipelines (in U.S. dollars)				
ANR	**63**	73	**254**	306
GTN[4]	**28**	26	**112**	131
Great Lakes[5]	**11**	20	**62**	101
TC PipeLines, LP[1][6][7]	**17**	21	**74**	85
Other U.S. Pipelines (Iroquois[1], Bison[4], Portland[7][8])	**32**	31	**111**	111
International (Tamazunchale, Guadalajara[9], TransGas[1], Gas Pacifico/INNERGY[1])	**27**	25	**112**	77
General, administrative and support costs	**(4)**	(3)	**(8)**	(9)
Non-controlling interests[7]	**39**	46	**161**	173
U.S. and International Natural Gas Pipelines Comparable EBITDA[2]	**213**	239	**878**	975
Depreciation and amortization[3]	**(54)**	(56)	**(218)**	(214)
U.S. and International Natural Gas Pipelines Comparable EBIT[2]	**159**	183	**660**	761
Foreign exchange	**(1)**	5	**-**	(7)
U.S. and International Natural Gas Pipelines Comparable EBIT[2] (in Canadian dollars)	**158**	188	**660**	754
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[2]	**(4)**	(15)	**(29)**	(52)
Natural Gas Pipelines Comparable EBIT[2]	**454**	481	**1,808**	1,952
Summary:				
Natural Gas Pipelines Comparable EBITDA[2]	**690**	716	**2,741**	2,875
Depreciation and amortization	**(236)**	(235)	**(933)**	(923)
Natural Gas Pipelines Comparable EBIT[2]	**454**	481	**1,808**	1,952

(1) Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect the Company's share of equity income from these investments.
(2) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Does not include depreciation and amortization from equity investments.
(4) Results reflect TransCanada's direct ownership interest of 75 per cent effective May 2011 and 100 per cent prior to that date.
(5) Represents TransCanada's 53.6 per cent direct ownership interest.
(6) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. As a result, TC PipeLines, LP's results include TransCanada's decreased ownership in TC PipeLines, LP and TransCanada's effective ownership through TC PipeLines, LP of 8.3 per cent of each of GTN and Bison since May 2011.
(7) Non-Controlling Interests reflect Comparable EBITDA for the portions of TC PipeLines, LP and Portland not owned by TransCanada.
(8) Includes TransCanada's 61.7 per cent ownership interest.
(9) Includes Guadalajara's operations since June 2011 when the asset was placed in service.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited) (millions of dollars)	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Canadian Mainline	**47**	60	**187**	246
Alberta System	**55**	51	**208**	200
Foothills	**4**	4	**19**	22

Canadian Natural Gas 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 National Energy Board decision with respect to its 2012-2013 tolls application, Canadian Mainline's 2012 results reflect the last approved rate of return on common equity 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 as a result of a higher average investment base, 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. and International Natural Gas Pipelines

ANR's Comparable EBITDA in fourth quarter 2012 of US$63 million decreased US$10 million compared to the same period in 2011 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 and was primarily the result of lower transportation revenue due to uncontracted capacity and lower rates compared to the same period in 2011.

Business Development

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.

Operating Statistics

Year ended December 31 *(unaudited)*	Canadian Mainline(1) 2012	Canadian Mainline(1) 2011	Alberta System(2) 2012	Alberta System(2) 2011	ANR(3) 2012	ANR(3) 2011
Average investment base (millions of dollars)	**5,737**	6,179	**5,501**	5,074	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**1,551**	1,887	**3,645**	3,517	**1,620**	1,706
Average per day	**4.2**	5.2	**10.0**	9.6	**4.4**	4.7

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the year ended December 31, 2012 were 859 billion cubic feet (Bcf) (2011 – 1,160 Bcf); average per day was 2.4 Bcf (2011 – 3.2 Bcf).

(2) Field receipt volumes for the Alberta System for the year ended December 31, 2012 were 3,660 Bcf (2011 – 3,622 Bcf); average per day was 10.0 Bcf (2011 – 9.9 Bcf).

(3) Under its current rates, which are approved by the FERC, ANR's results are not impacted by changes in its average investment base.

Oil Pipelines

Oil Pipelines' Comparable EBIT in fourth quarter 2012 was $136 million compared to $144 million in the same period in 2011.

Oil Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	Eleven months ended December 31 2011
Keystone Pipeline System	**180**	179	**712**	589
Oil Pipelines Business Development	**(8)**	-	**(14)**	(2)
Oil Pipelines Comparable EBITDA[1]	**172**	179	**698**	587
Depreciation and amortization	**(36)**	(35)	**(145)**	(130)
Oil Pipelines Comparable EBIT[1]	**136**	144	**553**	457
Comparable EBIT denominated as follows:				
Canadian dollars	**44**	51	**191**	159
U.S. dollars	**94**	91	**363**	301
Foreign exchange	**(2)**	2	**(1)**	(3)
Oil Pipelines Comparable EBIT[1]	**136**	144	**553**	457

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.

The Keystone Pipeline System's Comparable EBITDA of $180 million in fourth quarter 2012 is consistent with the same period in 2011.

EBITDA from the Keystone Pipeline System is primarily generated from payments received under long-term commercial arrangements for capacity that are not dependant on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA.

Business Development spending increased $8 million in fourth quarter 2012 compared to the same period in 2011 and reflected increased business development activity and related costs.

Energy

Energy's Comparable EBIT was $154 million in fourth quarter 2012 compared to $187 million for the same period in 2011.

Energy Results

(unaudited) (millions of dollars)	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Canadian Power				
Western Power[1][2]	**84**	142	**335**	483
Eastern Power[1][3]	**94**	82	**345**	297
Bruce Power[1]	**(8)**	(1)	**14**	110
General, administrative and support costs	**(14)**	(15)	**(48)**	(43)
Canadian Power Comparable EBITDA[4]	**156**	208	**646**	847
Depreciation and amortization[5]	**(35)**	(35)	**(152)**	(141)
Canadian Power Comparable EBIT[4]	**121**	173	**494**	706
U.S. Power (in U.S. dollars)				
Northeast Power	**62**	44	**257**	314
General, administrative and support costs	**(14)**	(12)	**(48)**	(41)
U.S. Power Comparable EBITDA[4]	**48**	32	**209**	273
Depreciation and amortization	**(31)**	(28)	**(121)**	(109)
U.S. Power Comparable EBIT[4]	**17**	4	**88**	164
Foreign exchange	**-**	(1)	**-**	(4)
U.S. Power Comparable EBIT[4] (in Canadian dollars)	**17**	3	**88**	160
Natural Gas Storage				
Alberta Storage[1]	**23**	24	**77**	84
General, administrative and support costs	**(3)**	(2)	**(10)**	(6)
Natural Gas Storage Comparable EBITDA[4]	**20**	22	**67**	78
Depreciation and amortization[5]	**(2)**	(3)	**(10)**	(12)
Natural Gas Storage Comparable EBIT[4]	**18**	19	**57**	66
Energy Business Development Comparable EBITDA and EBIT[4]	**(2)**	(8)	**(19)**	(25)
Energy Comparable EBIT[1][4]	**154**	187	**620**	907
Summary:				
Energy Comparable EBITDA[1][4]	**222**	254	**903**	1,168
Depreciation and amortization[5]	**(68)**	(67)	**(283)**	(261)
Energy Comparable EBIT[1][4]	**154**	187	**620**	907

(1) Results from ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta (up to December 18, 2012) reflect the Company's share of equity income from these investments. On December 18, 2012, the Company acquired the remaining 40 per cent interest in CrossAlta to bring its ownership interest to 100 per cent.

(2) Includes Coolidge effective May 2011.

(3) Includes Cartier Wind phase two of Gros-Morne effective November 2012, phase one of Gros-Morne effective November 2011, and Montagne-Sèche effective November 2011.

(4) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.

(5) Does not include depreciation and amortization of equity investments.

Canadian Power

Western and Eastern Canadian Power Comparable EBIT(1)(2)(3)

(unaudited) *(millions of dollars)*	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Revenues				
Western power	**158**	219	**640**	822
Eastern power	**106**	105	**415**	391
Other(4)	**25**	15	**91**	69
	289	339	**1,146**	1,282
Income from Equity Investments(5)	**23**	32	**68**	117
Commodity Purchases Resold				
Western power	**(74)**	(89)	**(281)**	(368)
Other(6)	**(2)**	4	**(5)**	(9)
	(76)	(85)	**(286)**	(377)
Plant operating costs and other	**(58)**	(62)	**(218)**	(242)
Sundance A PPA arbitration decision	**-**	-	**(30)**	-
General, administrative and support costs	**(14)**	(15)	**(48)**	(43)
Comparable EBITDA(1)	**164**	209	**632**	737
Depreciation and amortization(7)	**(35)**	(35)	**(152)**	(141)
Comparable EBIT(1)	**129**	174	**480**	596

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge effective May 2011.
(3) Includes Cartier Wind phase two of Gros-Morne effective November 2012, phase one of Gros-Morne effective November 2011, and Montagne-Sèche effective November 2011.
(4) Includes sales of excess natural gas purchased for generation and thermal carbon black.
(5) Results reflect equity income from TransCanada's 50 per cent ownership interest in each of ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
(6) Includes the cost of excess natural gas not used in operations.
(7) Excludes depreciation and amortization of equity investments.

Western and Eastern Canadian Power Operating Statistics(1)

(unaudited)	Three months ended December 31 2012	2011	Year ended December 31 2012	2011
Volumes (GWh)				
Generation				
Western Power(2)	**714**	669	**2,691**	2,606
Eastern Power(3)	**908**	852	**4,384**	3,714
Purchased				
Sundance A & B and Sheerness PPAs(4)	**2,017**	1,875	**6,906**	7,909
Other purchases	**-**	45	**46**	248
	3,639	3,441	**14,027**	14,477
Contracted				
Western Power(2)	**2,192**	2,125	**8,240**	8,381
Eastern Power(3)	**908**	852	**4,384**	3,714
Spot				
Western Power	**539**	464	**1,403**	2,382
	3,639	3,441	**14,027**	14,477
Plant Availability(5)				
Western Power(2)(6)	**97%**	97%	**96%**	97%
Eastern Power(3)(7)	**93%**	88%	**90%**	93%

(1) Includes TransCanada's share of equity investments' volumes.

(2) Includes Coolidge effective May 2011.
(3) Includes Cartier Wind phases one and two of Gros-Morne effective November 2011 and November 2012, respectively, and Montagne-Sèche effective November 2011. Also includes volumes related to TransCanada's 50 per cent ownership interest in Portlands Energy.
(4) Includes TransCanada's 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.
(5) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(6) Excludes facilities that provide power under PPAs.
(7) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

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.

Throughout 2011 and first quarter 2012, revenues and costs related to the Sundance A PPA had been recorded as though the outages of Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA. As a result of the Sundance A PPA arbitration decision received in July 2012, no further revenues and costs related to the PPA will be recorded until Units 1 and 2 are returned to service because the plant is in force majeure. Comparable EBITDA for the three months ended December 31, 2011 included $57 million of accrued earnings related to the Sundance A PPA.

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.

Western Power's Commodity Purchases Resold of $74 million decreased $15 million compared to the same period in 2011 primarily due to the Sundance A PPA force majeure, partially offset by higher purchased volumes as a result of lower PPA plant outage days.

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.

Income from Equity Investments of $23 million decreased $9 million compared to the same period in 2011 primarily due to the Sundance B PPA arbitration decision. 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 the facility operator, TransAlta Corporation. The ASTC Power Partnership, which holds the Sundance B PPA, disputed the claim under the binding dispute resolution process provided in the PPA as it did not believe TransAlta's claim met the test of force majeure. TransCanada therefore recorded equity earnings from its 50 per cent ownership interest in ASTC Power Partnership as though this event was a normal plant outage. In November 2012, an arbitration decision was reached with the arbitration panel granting partial force majeure relief to TransAlta and TransCanada reduced fourth quarter equity earnings by $11 million to reflect the amount which will not be recovered as a result of the decision.

Approximately 80 per cent of Western Power sales volumes were sold under contract in fourth quarter 2012, compared to 82 per cent in fourth quarter 2011. To reduce its exposure to spot market prices in Alberta, as at December 31, 2012, Western Power had entered into fixed-price power sales contracts to sell approximately 6,700 gigawatt hours (GWh) for 2013 and 4,300 GWh for 2014.

Eastern Power's sales volumes were 100 per cent sold under contract and are expected to be fully contracted going forward.

Bruce Power Results

(TransCanada's share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Income/(Loss) from Equity Investments[1]				
Bruce A	**(54)**	(15)	**(149)**	33
Bruce B	**46**	14	**163**	77
	(8)	(1)	**14**	110
Comprised of:				
Revenues	**228**	181	**763**	817
Operating expenses	**(165)**	(148)	**(567)**	(565)
Depreciation and other	**(71)**	(34)	**(182)**	(142)
	(8)	(1)	**14**	110
Bruce Power – Other Information				
Plant availability[2]				
Bruce A[3]	**52%**	68%	**54%**	90%
Bruce B	**100%**	89%	**95%**	88%
Combined Bruce Power	**79%**	82%	**81%**	89%
Planned outage days				
Bruce A	**123**	55	**336**	60
Bruce B	**-**	43	**46**	135
Unplanned outage days				
Bruce A	**11**	3	**18**	16
Bruce B	**-**	-	**25**	24
Sales volumes (GWh)[1]				
Bruce A[3]	**1,609**	1,050	**4,194**	5,475
Bruce B	**2,278**	1,956	**8,475**	7,859
	3,887	3,006	**12,669**	13,334
Realized sales price per MWh				
Bruce A	**$68**	$66	**$68**	$66
Bruce B[4]	**$54**	$53	**$55**	$54
Combined Bruce Power	**$57**	$56	**$57**	$57

(1) Represents TransCanada's 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
(2) Plant availability represents the percentage of time in a year that 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 Units 1 and 2 which were returned to service on October 22 and October 31, respectively.
(4) Includes revenues received under the floor price mechanism and from contract settlements as well as volumes and revenues associated with deemed generation.

TransCanada's 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.

Both Units 1 and 2 operated at reduced output levels following their return to service and, in late November 2012, Bruce Power took Unit 1 offline for an approximate 30 day planned 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 loss rates and reduced availability percentages in 2013.

TransCanada's 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.

Under a contract with the Ontario Power Authority (OPA), all output from Bruce A in fourth quarter 2012 was sold at a fixed price of $68.23 per MWh (before recovery of fuel costs from the OPA) compared to $66.33 per MWh in fourth quarter 2011. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $51.62 per MWh in fourth quarter 2012 compared to $50.18 per MWh in fourth quarter 2011. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues were subject to repayment in 2012 or 2011.

The Bruce A Unit 4 outage, which commenced on August 2, 2012, is expected to be completed in first quarter 2013. Planned maintenance on Bruce B units is scheduled to occur in the first half of 2013.

The overall plant availability percentage in 2013 is expected to be approximately 90 per cent for Bruce A and high 80's 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

U.S. Power Comparable EBIT(1)(2)

(unaudited) *(millions of U.S. dollars)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Revenues				
Power(3)	**353**	208	**1,189**	1,139
Capacity	**53**	44	**234**	227
Other(4)	**22**	26	**51**	80
	428	278	**1,474**	1,446
Commodity purchases resold	**(217)**	(119)	**(765)**	(618)
Plant operating costs and other(4)	**(149)**	(115)	**(452)**	(514)
General, administrative and support costs	**(14)**	(12)	**(48)**	(41)
Comparable EBITDA(1)	**48**	32	**209**	273
Depreciation and amortization	**(31)**	(28)	**(121)**	(109)
Comparable EBIT(1)	**17**	4	**88**	164

(1) Refer to the Non-GAAP Measures section of this news release for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Certain comparative figures have been reclassified to conform with the financial statement presentation adopted for the current period.
(3) The realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood, the activity level of which decreased in 2012.

U.S. Power Operating Statistics

(unaudited)	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Physical Sales Volumes (GWh)				
Supply				
Generation	**2,276**	1,511	**7,567**	6,880
Purchased	**2,550**	1,241	**9,408**	6,018
	4,826	2,752	**16,975**	12,898
Plant Availability(1)	**81%**	83%	**85%**	87%

(1) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.

U.S. Power's Comparable EBITDA of US$48 million for the three months ended December 31, 2012 increased US$16 million compared to the same period in 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.

Physical sales volumes for the three months ended December 31, 2012 have increased compared to the same period in 2011 largely due to higher purchased volumes to serve increased sales to wholesale, commercial and industrial customers in the PJM and New England markets. Generation volumes at Ravenswood were higher as the plant ran at higher than normal levels both during and following Superstorm Sandy when damage at several other third party power and transmission facilities reduced power supply in the area. This increase was partially offset by lower hydro volumes.

U.S. Power's Power Revenue of US$353 million for the three months ended December 31, 2012 increased US$145 million compared to the same period in 2011. The increase was primarily due to higher sales volumes in addition to higher realized power prices.

Capacity Revenue of US$53 million for the three months ended December 31, 2012 increased US$9 million compared to the same period in 2011 due to higher realized capacity prices in New York, partially offset by lower capacity prices in New England.

Commodity Purchases Resold of US$217 million for the three months ended December 31, 2012 increased US$98 million compared to the same period in 2011 due to higher volumes of physical power purchased for resale under power sales commitments to wholesale, commercial and industrial customers, higher load serving costs, and higher prices paid for power purchased.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of US$149 million for the three months ended December 31, 2012 increased US$34 million compared to the same period in 2011, primarily due to higher generation volumes at the Ravenswood facility.

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

Natural Gas Storage's Comparable EBITDA of $20 million for the three months ended December 31, 2012 was comparable to the same period in 2011.

Other Income Statement Items

Comparable Interest Expense

(unaudited) *(millions of dollars)*	Three months ended December 31 **2012**	 2011	Year ended December 31 **2012**	 2011
Interest on long-term debt[2]				
Canadian dollar-denominated	**128**	125	**513**	490
U.S. dollar-denominated	**186**	185	**740**	734
Foreign exchange	**(1)**	4	**-**	(7)
	313	314	**1,253**	1,217
Other interest and amortization	**9**	8	**23**	24
Capitalized interest	**(76)**	(71)	**(300)**	(302)
Comparable Interest Expense[1]	**246**	251	**976**	939

(1) Refer to the Non-GAAP Measures section in this news release for further discussion of Comparable Interest Expense.
(2) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense of $246 million for the three months ended December 31, 2012 decreased $5 million compared to the same period in 2011. The decrease primarily reflected higher capitalized interest for the Gulf Coast Project partially offset by reduced capitalized interest for the Company's investment in Bruce Power as a result of placing refurbished units in service.

Comparable Interest Income and Other of $20 million for the three months ended December 31, 2012 increased $12 million compared to the same period in 2011. The increase in fourth quarter reflected realized gains in 2012 compared to losses in 2011 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Condensed Consolidated Statement of Income

(unaudited) *(millions of dollars except per share amounts)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Revenues				
Natural Gas Pipelines	**1,087**	1,137	**4,264**	4,244
Oil Pipelines	**270**	252	**1,039**	827
Energy	**732**	626	**2,704**	2,768
	2,089	2,015	**8,007**	7,839
Income from Equity Investments	**61**	87	**257**	415
Operating and Other Expenses				
Plant operating costs and other	**731**	712	**2,577**	2,358
Commodity purchases resold	**291**	209	**1,049**	991
Property taxes	**88**	83	**434**	410
Depreciation and amortization	**343**	341	**1,375**	1,328
	1,453	1,345	**5,435**	5,087
Financial Charges/(Income)				
Interest expense	**246**	251	**976**	937
Interest income and other	**(15)**	(43)	**(85)**	(55)
	231	208	**891**	882
Income before Income Taxes	**466**	549	**1,938**	2,285
Income Taxes Expense				
Current	**80**	13	**181**	210
Deferred	**38**	113	**285**	365
	118	126	**466**	575
Net Income	**348**	423	**1,472**	1,710
Net Income Attributable to Non-Controlling Interests	**28**	33	**118**	129
Net Income Attributable to Controlling Interests	**320**	390	**1,354**	1,581
Preferred Share Dividends	**14**	14	**55**	55
Net Income Attributable to Common Shares	**306**	376	**1,299**	1,526
Net Income per Common Share				
Basic	**$0.43**	$0.53	**$1.84**	$2.17
Diluted	**$0.43**	$0.53	**$1.84**	$2.17
Dividends Declared per Common Share	**$0.44**	$0.42	**$1.76**	$1.68
Weighted Average Number of Common Shares (millions)				
Basic	**705**	703	**705**	702
Diluted	**705**	704	**706**	703

Condensed Consolidated Statement of Cash Flows

(unaudited) *(millions of dollars)*	Three months ended December 31 **2012**	2011	Year ended December 31 **2012**	2011
Cash Generated From Operations				
Net income	**348**	423	**1,472**	1,710
Depreciation and amortization	**343**	341	**1,375**	1,328
Deferred income taxes	**38**	113	**285**	365
Income from equity investments	**(61)**	(87)	**(257)**	(415)
Distributed earnings received from equity investments	**124**	86	**376**	393
Employee post-retirement benefits funding lower than/(in excess of) expense	**22**	(6)	**9**	(2)
Other	**4**	(33)	**24**	72
Decrease in operating working capital	**207**	90	**287**	235
Net cash provided by operations	**1,025**	927	**3,571**	3,686
Investing Activities				
Capital expenditures	**(1,040)**	(920)	**(2,595)**	(2,513)
Equity investments	**(95)**	(182)	**(652)**	(633)
Acquisitions, net of cash acquired	**(214)**	-	**(214)**	-
Deferred amounts and other	**123**	(41)	**205**	92
Net cash used in investing activities	**(1,226)**	(1,143)	**(3,256)**	(3,054)
Financing Activities				
Dividends on common and preferred shares	**(325)**	(310)	**(1,281)**	(1,016)
Distributions paid to non-controlling interests	**(34)**	(44)	**(135)**	(131)
Notes payable issued/(repaid), net	**790**	33	**449**	(224)
Long-term debt issued, net of issue costs	**3**	1,049	**1,491**	1,622
Repayment of long-term debt	**(198)**	(326)	**(980)**	(1,272)
Common shares issued, net of issue costs	**18**	19	**53**	58
Partnership units issued, net of issue costs	**-**	-	**-**	321
Net cash provided by/(used in) financing activities	**254**	421	**(403)**	(642)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**4**	(8)	**(15)**	4
Increase/(Decrease) in Cash and Cash Equivalents	**57**	197	**(103)**	(6)
Cash and Cash Equivalents				
Beginning of period	**494**	457	**654**	660
Cash and Cash Equivalents				
End of period	**551**	654	**551**	654

Condensed Consolidated Balance Sheet

December 31 *(unaudited)(millions of dollars)*	**2012**	2011
ASSETS		
Current Assets		
Cash and cash equivalents	**551**	654
Accounts receivable	**1,052**	1,094
Inventories	**224**	248
Other	**997**	1,114
	2,824	3,110
Plant, Property and Equipment, net of accumulated depreciation of $16,540 and $15,406, respectively	**33,713**	32,467
Equity Investments	**5,366**	5,077
Goodwill	**3,458**	3,534
Regulatory Assets	**1,629**	1,684
Intangible and Other Assets	**1,343**	1,466
	48,333	47,338
LIABILITIES		
Current Liabilities		
Notes payable	**2,275**	1,863
Accounts payable and other	**2,344**	2,359
Accrued interest	**368**	365
Current portion of long-term debt	**894**	935
	5,881	5,522
Regulatory Liabilities	**268**	297
Other Long-Term Liabilities	**882**	929
Deferred Income Tax Liabilities	**3,953**	3,591
Long-Term Debt	**18,019**	17,724
Junior Subordinated Notes	**994**	1,016
	29,997	29,079
EQUITY		
Common shares, no par value	**12,069**	12,011
Issued and outstanding:		
December 31, 2012 - 705 million shares		
December 31, 2011 – 704 million shares		
Preferred shares	**1,224**	1,224
Additional paid-in capital	**379**	380
Retained earnings	**4,687**	4,628
Accumulated other comprehensive loss	**(1,448)**	(1,449)
Controlling Interests	**16,911**	16,794
Non-controlling interests	**1,425**	1,465
	18,336	18,259
	48,333	47,338

Segmented Information

Three months ended December 31 (unaudited) (millions of dollars)	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines[1] 2012	Oil Pipelines[1] 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Revenues	**1,087**	1,137	**270**	252	**732**	626	**-**	-	**2,089**	2,015
Income from equity investments	**37**	42	**-**	-	**24**	45	**-**	-	**61**	87
Plant operating costs and other	**(373)**	(406)	**(88)**	(66)	**(238)**	(211)	**(32)**	(29)	**(731)**	(712)
Commodity purchases resold	**-**	-	**-**	-	**(291)**	(209)	**-**	-	**(291)**	(209)
Property taxes	**(61)**	(58)	**(10)**	(7)	**(17)**	(18)	**-**	-	**(88)**	(83)
Depreciation and amortization	**(236)**	(235)	**(36)**	(35)	**(68)**	(67)	**(3)**	(4)	**(343)**	(341)
	454	480	**136**	144	**142**	166	**(35)**	(33)	**697**	757
Interest expense									**(246)**	(251)
Interest income and other									**15**	43
Income before income taxes									**466**	549
Income taxes expense									**(118)**	(126)
Net Income									**348**	423
Net Income Attributable to Non-Controlling Interests									**(28)**	(33)
Net Income Attributable to Controlling Interests									**320**	390
Preferred Share Dividends									**(14)**	(14)
Net Income Attributable to Common Shares									**306**	376

Year ended December 31 (unaudited) (millions of dollars)	Natural Gas Pipelines 2012	Natural Gas Pipelines 2011	Oil Pipelines[1] 2012	Oil Pipelines[1] 2011	Energy 2012	Energy 2011	Corporate 2012	Corporate 2011	Total 2012	Total 2011
Revenues	**4,264**	4,244	**1,039**	827	**2,704**	2,768	**-**	-	**8,007**	7,839
Income from equity investments	**157**	159	**-**	-	**100**	256	**-**	-	**257**	415
Plant operating costs and other	**(1,365)**	(1,221)	**(296)**	(209)	**(819)**	(842)	**(97)**	(86)	**(2,577)**	(2,358)
Commodity purchases resold	**-**	-	**-**	-	**(1,049)**	(991)	**-**	-	**(1,049)**	(991)
Property taxes	**(315)**	(307)	**(45)**	(31)	**(74)**	(72)	**-**	-	**(434)**	(410)
Depreciation and amortization	**(933)**	(923)	**(145)**	(130)	**(283)**	(261)	**(14)**	(14)	**(1,375)**	(1,328)
	1,808	1,952	**553**	457	**579**	858	**(111)**	(100)	**2,829**	3,167
Interest expense									**(976)**	(937)
Interest income and other									**85**	55
Income before income taxes									**1,938**	2,285
Income taxes expense									**(466)**	(575)
Net Income									**1,472**	1,710
Net Income Attributable to Non-Controlling Interests									**(118)**	(129)
Net Income Attributable to Controlling Interests									**1,354**	1,581
Preferred Share Dividends									**(55)**	(55)
Net Income Attributable to Common Shares									**1,299**	1,526

(1) Commencing in February 2011, TransCanada began recording earnings related to the Keystone Pipeline System.