FORTIS INC.

Third Quarter 2013

Dear Shareholder:

Fortis achieved third quarter net earnings attributable to common equity shareholders of $48 million, or $0.23 per common share, compared to $45 million, or $0.24 per common share, for the third quarter of 2012. Year-to-date net earnings attributable to common equity shareholders were $253 million, or $1.27 per common share, compared to $228 million, or $1.20 per common share, for the same period last year.

Results for the third quarter of 2013 were impacted by the Corporation's acquisition of CH Energy Group, Inc. ("CH Energy Group") on June 27, 2013 for US$1.5 billion, including the assumption of US$518 million of debt on closing. The net purchase price of the acquisition was initially financed using proceeds from a $601 million common equity offering and drawings under the Corporation's committed credit facility. Central Hudson Gas & Electric Corporation ("Central Hudson"), the main business of CH Energy Group, is a regulated transmission and distribution utility that serves 376,000 electricity and gas customers in New York State's Mid-Hudson River Valley. Central Hudson contributed $12 million to earnings for the third quarter of 2013, comparable with performance in the third quarter of 2012. Due to the common share offering and financing costs associated with the acquisition, earnings per common share for the third quarter of 2013 were not materially impacted by the acquisition of CH Energy Group.

Central Hudson has successfully integrated into the Fortis family. The acquisition is expected to be accretive to earnings per common share of Fortis beginning in 2015.

Regulated utilities comprise approximately 90% of total assets and serve more than 2.4 million customers across Canada and in New York State and the Caribbean. As at September 30, 2013, regulated rate base assets of Fortis exceed $10 billion.

Canadian Regulated Gas Utilities incurred a loss of $14 million compared to a loss of $6 million for the third quarter of 2012. The third quarter is normally a period of lower customer demand due to warmer temperatures. The higher loss largely related to higher operating and maintenance expenses, decreases in the allowed rate of return on common shareholders' equity ("ROE") and the equity component of capital structure as a result of the regulatory decision related to the first phase of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia, and lower-than-expected customer additions. The above items were partially offset by earnings contribution from growth in energy infrastructure investment.

Canadian Regulated Electric Utilities contributed earnings of $51 million compared to $55 million for the third quarter of 2012. FortisAlberta's earnings were approximately $1 million lower quarter over quarter, due to lower net transmission revenue and $1 million of costs related to flooding in southern Alberta in June 2013, largely offset by growth in energy infrastructure investment, customer growth and timing of operating expenses. FortisBC Electric's earnings decreased $2 million due to a decrease in the interim allowed ROE as a result of the regulatory decision related to the first phase of the GCOC Proceeding in British Columbia, lower pole-attachment revenue and higher effective income taxes. The decreases were partially offset by earnings contribution from growth in energy infrastructure investment and lower-than-expected finance charges. At Newfoundland Power, earnings were $1 million lower quarter over quarter, due to the impact of the reversal of statute-barred Part VI.1 tax in the third quarter of 2012, partially offset by growth in energy infrastructure investment and lower storm-related costs.

In April 2013 Newfoundland Power received a cost of capital decision maintaining the utility's allowed ROE at 8.8% and its common equity component of capital structure at 45% for 2013 through 2015. In May 2013 the British Columbia Utilities Commission issued its decision, effective January 1, 2013, on the first phase of its GCOC Proceeding. As a result, the allowed ROE for FortisBC Energy Inc. has been set at 8.75%, as compared to 9.50% for 2012, and the common equity component of capital structure has been reduced from 40.0% to 38.5%. The interim allowed ROEs for FortisBC Energy (Vancouver Island) Inc. ("FEVI"), FortisBC Energy (Whistler) Inc. ("FEWI") and FortisBC Electric were also reduced by 75 basis points for 2013 as a result of the first phase of the GCOC Proceeding, while the common equity components of their capital structures remain unchanged. Final allowed ROEs and capital structures for FEVI, FEWI and FortisBC Electric will be determined in the second phase of the GCOC Proceeding, which is currently underway. A decision on the proceeding is expected in the first half of 2014. FortisAlberta's final allowed ROE and capital structure for 2013 remain to be determined.

Caribbean Regulated Electric Utilities contributed $6 million to earnings, comparable with the third quarter of 2012.

Non-Regulated Fortis Generation contributed $8 million to earnings, up $3 million quarter over quarter. Improved performance mainly related to increased production in Belize due to higher rainfall.

Non-Utility operations contributed earnings of $6 million compared to $8 million for the third quarter of 2012. The decrease reflected a loss of approximately $2.5 million at Griffith Energy Services, Inc., the non-regulated petroleum supply operations of CH Energy Group, which is comparable with performance in the third quarter of 2012 and reflects the impact of seasonality. Improved performance at Fortis Properties' Hospitality Division partially offset the decrease in earnings.

Corporate and other expenses for the third quarter include $2 million of costs associated with the redemption of preference shares and a $2 million foreign exchange loss, compared to a $3 million foreign exchange loss in the third quarter of 2012. Excluding these impacts, Corporate and other expenses were $17 million for the third quarter, $3 million lower than the third quarter of 2012. The decrease was primarily due to a higher income tax recovery, resulting from the release of income tax provisions in the third quarter of 2013 and the recognition of income tax expense associated with Part VI.1 tax in the third quarter of 2012. Higher capitalized interest associated with the financing of construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion hydroelectric generating facility ("Waneta Expansion") was offset by higher interest on credit facility borrowings associated with financing the acquisition of CH Energy Group. The decrease in Corporate and other expenses was partially offset by higher preference share dividends.

Consolidated capital expenditures were approximately $809 million year-to-date 2013. Construction of the $900 million, 335-megawatt Waneta Expansion in British Columbia continues on time and on budget, with completion of the facility expected in spring 2015. Approximately $534 million has been invested in the Waneta Expansion since construction began in late 2010.

Cash flow from operating activities was $680 million year-to-date 2013 compared to $804 million for the same period last year, primarily due to unfavourable changes in working capital.

In July 2013 Fortis issued 10 million 4% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K for gross proceeds of $250 million. The proceeds were used to redeem all of the Corporation's 5.45% First Preference Shares, Series C in July 2013 for $125 million, to repay a portion of credit facility borrowings, and for other general corporate purposes. In October 2013 the Corporation closed a private placement of 10-year US$285 million unsecured notes at 3.84% and 30-year US$40 million unsecured notes at 5.08%. The proceeds were used to repay a portion of US dollar-denominated credit facility borrowings incurred to finance a portion of the CH Energy Group acquisition. In September 2013 FortisAlberta issued 30-year $150 million unsecured debentures at 4.85%, the proceeds of which are being used to repay credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

Fortis has consolidated credit facilities of $2.7 billion, of which $1.9 billion was unused as at September 30, 2013. In August 2013 the Corporation extended the maturity of its $1 billion committed revolving credit facility to July 2018.

We remain focused on completing our capital projects for 2013, which are expected to total approximately $1.2 billion. Our five-year capital program to the end of 2017 is projected to total $6 billion and will continue to drive growth in earnings and dividends.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2013
Dated November 1, 2013

TABLE OF CONTENTS

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the interim unaudited consolidated financial statements and notes thereto for the three and nine months ended September 30, 2013 and the MD&A and audited consolidated financial statements for the year ended December 31, 2012 included in the Corporation's 2012 Annual Report. Financial information contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the Management Discussion and Analysis ("MD&A") within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's forecast gross consolidated capital expenditures for 2013 and total capital spending over the five-year period 2013 through 2017; the expectation that capital investment over the above-noted five-year period will allow utility rate base and hydroelectric generation investment to increase at a combined compound annual growth rate of approximately 6%; the expected nature, timing and capital cost related to the construction of the Waneta Expansion hydroelectric generating facility ("Waneta Expansion"); the expectation that, based on current tax legislation, future earnings will not be materially impacted by Part VI.1 tax; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expected consolidated long-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2013; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expectation that the acquisition of CH Energy Group, Inc. will be accretive to earnings per common share of Fortis beginning in 2015; and the expectation that the Corporation's capital expenditure program will support continuing growth in earnings and dividends.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received and the expectation of regulatory stability; FortisAlberta continues to recover its cost of service and earn its allowed rate of return on common shareholders' equity ("ROE") under performance-based rate-setting, which commenced for a five-year term effective January 1, 2013; no significant variability in interest rates; no significant operational disruptions or environmental liability *due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for the fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited will not be expropriated by the GOB; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas commodity prices, electricity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.*

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A, the Corporation's MD&A for the year ended December 31, 2012 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2013 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at certain of the Corporation's regulated utilities in western Canada; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Fortis is the largest investor-owned gas and electric distribution utility in Canada. Its regulated utilities account for 90% of total assets and serve more than 2.4 million customers across Canada and in New York State and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investments are comprised of hotels and commercial real estate in Canada and petroleum supply operations in the Mid-Atlantic Region of the United States.

Year-to-date September 30, 2013, the Corporation's electricity distribution systems met a combined peak demand of approximately 6,380 megawatts ("MW") and its gas distribution system met a peak day demand of 1,238 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2013 and to the "Corporate Overview" section of the 2012 Annual MD&A.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation. Generally under COS regulation, the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences within an annual financial reporting period between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

When performance-based rate-setting ("PBR") mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent COS and earn its allowed ROE.

SIGNIFICANT ITEMS

Acquisition of CH Energy Group, Inc.: On June 27, 2013, Fortis acquired all of the outstanding common shares of CH Energy Group, Inc. ("CH Energy Group") for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. The net purchase price of approximately $1,019 million (US$972 million) was financed through proceeds from the issuance of 18.5 million common shares of Fortis pursuant to the conversion of Subscription Receipts on closing of the acquisition for proceeds of approximately $567 million, net of after-tax expenses, with the balance being initially funded through drawings under the Corporation's $1 billion committed credit facility.

CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation ("Central Hudson"), is a regulated transmission and distribution ("T&D") utility serving approximately 300,000 electricity and 76,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson accounts for approximately 93% of the total assets of CH Energy Group and is subject to regulation by the New York State Public Service Commission ("PSC") under a traditional COS model. CH Energy Group's non-regulated operations primarily consist of Griffith Energy Services, Inc. ("Griffith"), which mainly supplies petroleum products and related services to approximately 65,000 customers in the Mid-Atlantic Region of the United States.

To obtain regulatory approval of the acquisition, Fortis committed to provide Central Hudson's customers and community with approximately US$50 million in financial benefits. These incremental benefits outlined in the PSC order approving the acquisition include: (i) US$35 million to cover expenses that would normally be recovered in customer rates; (ii) guaranteed savings to customers of more than US$9 million over five years resulting from the elimination of costs CH Energy Group would otherwise incur as a public company; and (iii) the establishment of a US$5 million Community Benefit Fund to be used for low-income customer and economic development programs for communities and residents of the Mid-Hudson River Valley. In addition, electricity and natural gas customers of Central Hudson will benefit from a delivery rate freeze through to June 30, 2015. The Company is committed to invest US$215 million in capital expenditures over the same two-year period.

The above-noted commitments of US$35 million and US$5 million, together with acquisition-related expenses of approximately US$8 million, were recognized in the Corporation's earnings for the second quarter of 2013. The acquisition is expected to be accretive to earnings per common share of Fortis beginning in 2015.

For further information on Central Hudson, refer to the "Segmented Results of Operation – Regulated Gas & Electric Utility - United States" section of this MD&A.

First Preference Shares: In July 2013 Fortis issued 10 million 4% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K for gross proceeds of $250 million. The proceeds were used to redeem all of the Corporation's 5.45% First Preference Shares, Series C in July 2013 for $125 million, to repay a portion of credit facility borrowings, and for other general corporate purposes. Approximately $2 million of costs associated with the redemption of First Preference Shares, Series C were expensed in the third quarter.

Long-Term Debt Offering: In September 2013 FortisAlberta issued 30-year $150 million unsecured debentures at 4.85%. The proceeds of the debt offering are being used to repay credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

Part VI.1 Tax: In June 2013 the Government of Canada enacted previously announced legislative changes associated with Part VI.1 tax on the Corporation's preference share dividends. In accordance with US GAAP, income taxes are required to be recognized based on enacted tax legislation. In the second quarter of 2013, the Corporation recognized an approximate $25 million income tax recovery due to the enactment of higher deductions associated with Part VI.1 tax. The income tax recovery impacted earnings at Newfoundland Power, Maritime Electric and the Corporation as a result of the allocation of Part VI.1 tax in previous years. Currently, all legislative changes associated with Part VI.1 tax are enacted and, as a result, future earnings are not expected to be materially impacted by Part VI.1 tax.

Receipt of Regulatory Decisions: In March 2013 FortisAlberta received a decision from its regulator approving an interim increase in customer distribution rates, effective January 1, 2013, including interim approval of 60% of the revenue requirement associated with certain capital expenditures in 2013 not otherwise recovered under performance-based rates. The Company's final allowed ROE and capital structure for 2013 remain to be determined.

In April 2013 Newfoundland Power received a cost of capital decision maintaining the utility's allowed ROE at 8.8% and its common equity component of capital structure at 45% for 2013 through 2015.

In May 2013 the British Columbia Utilities Commission ("BCUC") issued its decision, effective January 1, 2013, on the first phase of its Generic Cost of Capital ("GCOC") Proceeding. As a result, the allowed ROE for FortisBC Energy Inc. ("FEI") has been set at 8.75%, as compared to 9.50% for 2012, and the common equity component of capital structure has been reduced from 40.0% to 38.5%. The interim allowed ROEs for FortisBC Energy (Vancouver Island) Inc. ("FEVI"), FortisBC Energy (Whistler) Inc. ("FEWI") and FortisBC Electric were also reduced by 75 basis points for 2013 as a result of the first phase of the GCOC Proceeding, while the common equity components of their capital structures remain unchanged. Final allowed ROEs and capital structures for FEVI, FEWI and FortisBC Electric will be determined in the second phase of the GCOC Proceeding, which is currently underway. A decision on the proceeding is expected in the first half of 2014.

For further discussion on the nature of the above regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Settlement of Expropriation Matters - Exploits River Hydro Partnership: In March 2013 the Corporation and the Government of Newfoundland and Labrador ("Government") settled all matters, including release from all debt obligations, pertaining to the Government's December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by the Exploits River Hydro Partnership ("Exploits Partnership"), in which Fortis held an indirect 51% interest. As a result of the settlement, an extraordinary after-tax gain of approximately $22 million was recognized in the first quarter of 2013.

Acquisition of the Electrical Utility Assets from the City of Kelowna: FortisBC Electric acquired the electrical utility assets of the City of Kelowna (the "City") for approximately $55 million in March 2013, which now allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000.

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's business is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Key financial highlights for the third quarter and year-to-date periods ended September 30, 2013 and September 30, 2012 are provided in the following table.

Consolidated Financial Highlights (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions, except for common share data)	**2013**	2012	Variance	**2013**	2012	Variance
Revenue	**971**	714	257	**2,874**	2,655	219
Energy Supply Costs	**356**	235	121	**1,143**	1,092	51
Operating Expenses	**299**	203	96	**726**	621	105
Depreciation and Amortization	**141**	118	23	**400**	351	49
Other Income (Expenses), Net	**2**	1	1	**(36)**	(2)	(34)
Finance Charges	**103**	93	10	**284**	276	8
Income Tax Expense	**7**	7	-	**3**	44	(41)
Earnings Before Extraordinary Item	**67**	59	8	**282**	269	13
Extraordinary Gain, Net of Tax	**-**	-	-	**22**	-	22
Net Earnings	**67**	59	8	**304**	269	35
Net Earnings Attributable to:						
Non-Controlling Interests	**3**	3	-	**7**	7	-
Preference Equity Shareholders	**16**	11	5	**44**	34	10
Common Equity Shareholders	**48**	45	3	**253**	228	25
Net Earnings	**67**	59	8	**304**	269	35
Earnings per Common Share Before Extraordinary Item						
Basic *($)*	**0.23**	0.24	(0.01)	**1.16**	1.20	(0.04)
Diluted *($)*	**0.23**	0.24	(0.01)	**1.16**	1.19	(0.03)
Earnings per Common Share						
Basic *($)*	**0.23**	0.24	(0.01)	**1.27**	1.20	0.07
Diluted *($)*	**0.23**	0.24	(0.01)	**1.27**	1.19	0.08
Weighted Average Common Shares Outstanding *(# millions)*	**212.0**	190.2	21.8	**199.1**	189.6	9.5
Cash Flow from Operating Activities	**102**	221	(119)	**680**	804	(124)

Factors Contributing to Quarterly and Year-to-Date
Revenue Variances

Favourable

- The acquisition of CH Energy Group
- An increase in gas delivery rates at the FortisBC Energy companies and the base component of electricity rates at most of the regulated electric utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Growth in the number of customers, driven by FortisAlberta
- Increased electricity sales at FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Turks and Caicos
- Favourable foreign exchange associated with the translation of US dollar-denominated revenue
- Increased revenue at Fortis Properties

Unfavourable

- Lower commodity cost of natural gas charged to customers at the FortisBC Energy companies in the first half of 2013
- Decreases in the allowed ROEs at the FortisBC Energy companies and FortisBC Electric, and a decrease in the equity component of capital structure at FEI, effective January 1, 2013, as a result of the BCUC decision on the first phase of its GCOC Proceeding

- Lower average gas consumption by residential and commercial customers, and lower gas transportation volumes at the FortisBC Energy companies
- Lower net transmission revenue at FortisAlberta
- Decreased non-regulated hydroelectric production in Belize in the first half of 2013, partially offset by increased production in the third quarter of 2013

Factors Contributing to Quarterly and Year-to-Date
Energy Supply Costs Variances

Unfavourable
- The acquisition of CH Energy Group
- Increased electricity sales at FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Turks and Caicos, which increased fuel and power purchases
- Increased costs at Maritime Electric associated with the return to service of the New Brunswick Power Point Lepreau nuclear generating station ("Point Lepreau"), in the fourth quarter of 2012

Favourable
- Lower commodity cost of natural gas at the FortisBC Energy companies in the first half of 2013
- Lower average gas consumption by residential and commercial customers, and lower gas transportation volumes at the FortisBC Energy companies, which reduced natural gas purchases

Factors Contributing to Quarterly and Year-to-Date
Operating Expenses Variances

Unfavourable
- The acquisition of CH Energy Group
- General inflationary and employee-related cost increases at most of the Corporation's regulated utilities
- Higher operating and maintenance expenses at the FortisBC Energy companies, due to the timing of expenditures during 2012

Factors Contributing to Quarterly and Year-to-Date
Depreciation and Amortization Expense Variances

Unfavourable
- Continued investment in energy infrastructure at the Corporation's regulated utilities
- The acquisition of CH Energy Group

Factors Contributing to Quarterly and Year-to-Date
Other Income (Expenses), Net Variances

Favourable
- A $2 million foreign exchange loss in the third quarter of 2013 and a $3 million foreign exchange gain year-to-date 2013, compared to a $3 million foreign exchange loss in the third quarter and year-to-date periods in 2012, associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity

Unfavourable
- Approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, in expenses in the second quarter of 2013 associated with customer and community benefits offered by the Corporation related to the acquisition of CH Energy Group

Factors Contributing to Quarterly and Year-to-Date
Finance Charges Variances

Unfavourable
- The acquisition of CH Energy Group, including interest on the Corporation's credit facility borrowings associated with financing the acquisition
- Higher long-term debt levels in support of the utilities' capital expenditure programs

Favourable
- Higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion

Factors Contributing to Quarterly and Year-to-Date
Income Tax Expense Variances

Favourable

- An approximate $25 million income tax recovery in the second quarter of 2013, due to the enactment of higher deductions associated with Part VI.1 tax
- The release of income tax provisions of approximately $2 million and $7 million for the third quarter and year-to-date 2013, respectively
- Lower earnings before income taxes year-to-date 2013

Unfavourable

- The acquisition of CH Energy Group

Factor Contributing to Year-to-Date
Extraordinary Gain, Net of Tax Variance

Favourable

- An approximate $25 million ($22 million after-tax) extraordinary gain recognized in the first quarter of 2013 on the settlement of expropriation matters associated with the Exploits Partnership

Factors Contributing to Quarterly Earnings Variance

Favourable

- The acquisition of CH Energy Group, including earnings contribution of $12 million from Central Hudson and a net loss of approximately $2.5 million at Griffith
- Increased non-regulated hydroelectric production in Belize, due to higher rainfall
- Lower Corporate and other expenses primarily due to a higher income tax recovery, resulting from the release of income tax provisions in the third quarter of 2013 and the recognition of income tax expense associated with Part VI.1 tax in the third quarter of 2012, and a lower foreign exchange loss, partially offset by higher preference share dividends and redemption costs

Unfavourable

- Decreased earnings at the FortisBC Energy companies, primarily due to: (i) higher operating and maintenance expenses; (ii) decreases in the allowed ROE and the equity component of the capital structure as a result of the regulatory decision related to the first phase of the GCOC Proceeding; and (iii) lower-than-expected customer additions. The decreases were partially offset by earnings contribution from growth in energy infrastructure investment.
- Decreased earnings at FortisBC Electric mainly due to a decrease in the interim allowed ROE as a result of the regulatory decision related to first phase of the GCOC Proceeding, lower pole-attachment revenue and higher effective income taxes, partially offset by earnings contribution from growth in energy infrastructure investment and lower-than-expected finance charges
- Decreased earnings at FortisAlberta due to lower net transmission revenue and $1 million of costs related to flooding in southern Alberta in June 2013, largely offset by growth in energy infrastructure investment, customer growth and timing of operating expenses
- Decreased earnings at Newfoundland Power due to the $2.5 million reversal of statute-barred Part VI.1 tax in the third quarter of 2012, partially offset by growth in energy infrastructure investment and lower storm-related costs

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- An approximate $22 million after-tax extraordinary gain recognized in the first quarter of 2013 on the settlement of expropriation matters associated with the Exploits Partnership, partially offset by decreased production in Belize, due to lower rainfall in the first half of 2013
- Increased earnings at Newfoundland Power and Maritime Electric due to income tax recoveries associated with Part VI.1 tax of $13 million and $4 million, respectively, partially offset by the $2.5 million reversal of statute-barred Part VI.1 tax at Newfoundland Power in the third quarter of 2012
- The acquisition of CH Energy Group, as discussed above for the quarter
- Increased earnings at FortisAlberta, due to continued investment in energy infrastructure, customer growth and timing of operating expenses, partially offset by lower net transmission revenue and $1 million of costs related to flooding in southern Alberta in June 2013

Unfavourable

- Decreased earnings at the FortisBC Energy companies, for the same reasons discussed above for the quarter
- Higher Corporate and other expenses, due to $32 million in CH Energy Group transaction expenses and higher preference share dividends and redemption costs. The increases were partially offset by: (i) a higher income tax recovery due to $6 million associated with Part VI.1 tax and $7 million associated with the release of income tax provisions; (ii) a foreign exchange gain associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity; and (iii) lower finance charges.
- Decreased earnings at FortisBC Electric, for the same reasons discussed above for the quarter

SEGMENTED RESULTS OF OPERATIONS

The basis of segmentation of the Corporation's reportable segments is consistent with that disclosed in the 2012 Annual MD&A, except as follows as a result of the acquisition of CH Energy Group. Central Hudson is reported in a new segment "Regulated Gas & Electric Utility - United States"; and the former "Non-Regulated - Fortis Properties" segment is now "Non-Regulated - Non-Utility" and is comprised of Fortis Properties and Griffith.

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions)	**2013**	2012	Variance	**2013**	2012	Variance
Regulated Gas Utilities - Canadian						
FortisBC Energy Companies	**(14)**	(6)	(8)	**77**	89	(12)
Regulated Gas & Electric Utility - United States						
Central Hudson	**12**	-	12	**12**	-	12
Regulated Electric Utilities - Canadian						
FortisAlberta	***25***	*26*	*(1)*	***76***	*73*	*3*
FortisBC Electric	***11***	*13*	*(2)*	***37***	*38*	*(1)*
Newfoundland Power	***8***	*9*	*(1)*	***39***	*28*	*11*
Other Canadian Electric Utilities	***7***	*7*	*-*	***22***	*19*	*3*
	51	55	(4)	**174**	158	16
Regulated Electric Utilities - Caribbean	**6**	6	-	**15**	15	-
Non-Regulated - Fortis Generation	**8**	5	3	**35**	15	20
Non-Regulated - Non-Utility	**6**	8	(2)	**15**	17	(2)
Corporate and Other	**(21)**	(23)	2	**(75)**	(66)	(9)
Net Earnings Attributable to Common Equity Shareholders	**48**	45	3	**253**	228	25

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A. A discussion of the financial results of the Corporation's reporting segments follows.

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Financial Highlights (Unaudited)		**Quarter**			**Year-to-Date**	
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Gas Volumes *(petajoules ("PJ"))*	**25**	26	(1)	**132**	138	(6)
Revenue *($ millions)*	**194**	192	2	**932**	1,004	(72)
(Loss) Earnings *($ millions)*	**(14)**	(6)	(8)	**77**	89	(12)

(1) Includes FEI, FEVI and FEWI

Factors Contributing to Quarterly and Year-to-Date
Gas Volumes Variances

Unfavourable

- Lower average gas consumption by residential and commercial customers, due to warmer temperatures
- Lower gas transportation volumes, partially due to warmer temperatures

As at September 30, 2013, the total number of customers served by the FortisBC Energy companies was approximately 947,000. Net customer additions year-to-date 2013 were approximately 2,000.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the commodity cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Seasonality has a material impact on the earnings of the FortisBC Energy companies as a major portion of the gas distributed is used for space heating. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

Factors Contributing to Quarterly and Year-to-Date
Revenue Variances

Favourable

- An increase in the delivery component of customer rates, effective January 1, 2013, mainly due to ongoing investment in energy infrastructure and forecasted higher expenses recoverable from customers as reflected in the 2012/2013 revenue requirements decision received in April 2012
- Higher commodity cost of natural gas charged to customers in the third quarter of 2013

Unfavourable

- Lower commodity cost of natural gas charged to customers in the first half of 2013
- Decreases in the allowed ROE and the equity component of capital structure, effective January 1, 2013, as a result of the regulatory decision in May 2013 related to the first phase of the GCOC Proceeding in British Columbia
- Lower average gas consumption by residential and commercial customers, and lower gas transportation volumes

Factors Contributing to Quarterly and Year-to-Date
Earnings Variances

Unfavourable

- Higher operating and maintenance expenses, due to the timing of expenditures during 2012
- Decreases in the allowed ROE and the equity component of the capital structure, as discussed above. For the third quarter and year-to-date 2013 earnings were reduced by approximately $1 million and $9 million, respectively, as a result of the above regulatory decision.
- Lower-than-expected customer additions

Favourable

- Rate base growth, due to continued investment in energy infrastructure

REGULATED GAS & ELECTRIC UTILITY - UNITED STATES

CENTRAL HUDSON

Central Hudson's electric assets comprised approximately 78% of its total assets as at September 30, 2013, and include approximately 14,000 kilometres of distribution lines and 1,000 kilometres of transmission lines. The electric business met a peak demand of 1,202 MW year-to-date 2013. Central Hudson's natural gas assets comprise the remaining 22% of its total assets as at September 30, 2013, and include approximately 1,900 kilometres of distribution pipelines and more than 264 kilometres of transmission pipelines. The gas business met a peak day demand of 125 TJ year-to-date 2013, which occurred in the first quarter of 2013.

Central Hudson primarily relies on electricity purchases from third-party providers and the New York Independent System Operator ("NYISO")-administered energy and capacity markets to meet the demands of its full-service electricity customers. It also generates a small portion of its electricity requirements. Central Hudson purchases its gas supply requirements at various pipeline receipt points from a number of suppliers that it has contracted for firm transport capacity.

Regulation

Central Hudson is regulated by the PSC regarding such matters as rates, construction, operations, financing and accounting. Certain activities of the Company are subject to regulation by the U.S. Federal Energy Regulatory Commission under the *Federal Power Act* (United States). Central Hudson is also subject to regulation by the North American Electric Reliability Corporation.

Central Hudson operates under COS regulation as administered by the PSC. The PSC uses a future test year to establish of rates for the utility and, pursuant to this method, the determination of the approved rate of return on forecast rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined. Once rates are approved, they are not adjusted as a result of actual COS being different from that which was applied for, other than for certain prescribed costs that are eligible for deferral account treatment.

Central Hudson's allowed ROE is set at 10% on a deemed capital structure of 48% common equity. The Company began operating under a three-year rate order issued by the PSC effective July 1, 2010. As approved by the PSC in June 2013, the original three-year rate order has been extended for two years, through June 30, 2015, as a condition required to close the acquisition of CH Energy Group by Fortis. Effective July 1, 2013, Central Hudson is also subject to a modified earnings sharing mechanism, whereby the Company and customers equally share earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

Central Hudson's approved regulatory regime allows for full recovery of purchased electricity and natural gas costs. The Company's rates also include Revenue Decoupling Mechanisms ("RDMs") which are intended to minimize the earnings impact resulting from reduced energy consumption as energy-efficiency programs are implemented. The RDMs allow the Company to recognize electricity delivery revenue and gas revenue at the levels approved in rates for most of Central Hudson's customer base. Deferral account treatment is approved for certain other specified costs, including provisions for manufactured gas plant ("MGP") site remediation, pension and other post-employment benefit ("OPEB") costs.

Financial Highlights

Financial Highlights (Unaudited) *(1)*	**Quarter**
Period Ended September 30	**2013**
Average US:CDN Exchange Rate *(2)*	**1.04**
Electricity Sales *(gigawatt hours ("GWh"))*	**1,420**
Gas Volumes *(PJ)*	**4**
Revenue *($ millions)*	**170**
Earnings *($ millions)*	**12**

(1) Financial results of Central Hudson are from June 27, 2013, the date of acquisition. For additional information on the acquisition of CH Energy Group, including Central Hudson, refer to the "Significant Items - Acquisition of CH Energy Group, Inc." section of this MD&A.

(2) The reporting currency of Central Hudson is the US dollar.

Electricity Sales and Gas Volumes

Seasonality impacts the delivery revenues of Central Hudson, as electricity sales are highest during the summer months, primarily due to the use of air conditioning and other cooling equipment, and gas volumes are highest during the winter months, primarily due to space heating usage.

Electricity sales for the third quarter were 1,420 GWh compared to 1,454 GWh for the same period last year. The decrease was mainly due to cooler temperatures in the third quarter of 2013. Gas volumes for the third quarter were 4 PJ compared to 6 PJ for the same period last year. The decrease was primarily due to lower volumes delivered to a power generating facility as a result of reduced facility operations and lower volumes for resale.

A portion of Central Hudson's electricity sales and gas volumes are to other entities for resale. Electricity sales for resale do not have an impact on earnings, as any related earnings or loss is refunded to or collected from customers, respectively. For gas volumes for resale, 85% of any related earnings or loss is refunded to or collected from customers, respectively.

Revenue

Revenue for the third quarter was US$164 million compared to US$167 million for the same period last year. The decrease was primarily due to lower gas volumes for resale, partially offset by higher revenue from electricity energy efficiency programs.

Earnings

Earnings for the third quarter were comparable with the same period last year.

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Energy Deliveries *(GWh)*	**3,925**	4,099	(174)	**12,411**	12,434	(23)
Revenue *($ millions)*	**119**	117	2	**354**	335	19
Earnings *($ millions)*	**25**	26	(1)	**76**	73	3

Factors Contributing to Quarterly and Year-to-Date Energy Deliveries Variances

Unfavourable

- Lower average consumption by customers in oil and gas industry, due to decreased activity associated with a low commodity price for natural gas
- Lower average consumption by residential and commercial customers, primarily in the third quarter of 2013, as a result of flooding in southern Alberta in June 2013 and cooler temperatures, which reduced air conditioning load
- Lower average consumption by farm and irrigation customers, primarily due to increased rainfall in the second and third quarters of 2013

Favourable

- Growth in the number of customers, with the total number of customers increasing by approximately 9,000 year over year as at September 30, 2013, driven by favourable economic conditions

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Quarterly and Year-to-Date
Revenue Variances

Favourable
- An interim increase in customer electricity distribution rates, effective January 1, 2013, associated with the regulator's interim decision received in March 2013 related to FortisAlberta's PBR Compliance Application
- Growth in the number of customers

Unfavourable
- Lower net transmission revenue, due to favourable volume variances of approximately $3.5 million and $6.5 million recognized in the third quarter and year-to-date 2012. As approved by the regulator in April 2012, FortisAlberta assumed the risk of volume variances related to net transmission costs during 2012. The deferral of transmission volume variances, however, was reinstated by the regulator effective January 1, 2013. Year-to-date 2013, lower net transmission revenue was partially offset by approximately $2 million recognized in the first quarter of 2013 associated with the finalization of the 2012 net transmission volume variances.

Factors Contributing to Quarterly and Year-to-Date
Earnings Variances

Unfavourable
- Lower net transmission revenue of approximately $3.5 million for the quarter and $4.5 million year to date, as discussed above
- Restoration costs of approximately $1 million in the third quarter of 2013, related to flooding in southern Alberta in June 2013

Favourable
- Rate base growth, due to continued investment in energy infrastructure
- Growth in the number of customers
- Timing of operating expenses

FORTISBC ELECTRIC *[1]*

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Electricity Sales *(GWh)*	**752**	728	24	**2,324**	2,313	11
Revenue *($ millions)*	**74**	71	3	**230**	225	5
Earnings *($ millions)*	**11**	13	(2)	**37**	38	(1)

[1] Includes the regulated operations of FortisBC Inc. and operating, maintenance and management services related to the Waneta, Brilliant and Arrow Lakes hydroelectric generating plants. Excludes the non-regulated generation operations of FortisBC Inc.'s wholly owned partnership, Walden Power Partnership. In March 2013 FortisBC Inc. acquired the City of Kelowna's electrical utility assets for approximately $55 million. For further information, refer to the "Significant Items" section of this MD&A.

Factors Contributing to Quarterly and Year-to-Date
Electricity Sales Variances

Favourable
- Higher average consumption, due to warmer temperatures in the third quarter of 2013

Unfavourable
- Lower average consumption, due to warmer temperatures in the first quarter of 2013

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- An increase in customer electricity rates, effective January 1, 2013, mainly due to ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers as reflected in the 2012/2013 revenue requirements decision received in August 2012
- Revenue associated with the acquisition of the City of Kelowna's electrical utility assets in March 2013
- The 3.3% and 0.5% increase in electricity sales for the quarter and year to date, respectively

Unfavourable

- A decrease in the interim allowed ROE, effective January 1, 2013, as a result of the regulatory decision in May 2013 related to the first phase of the GCOC Proceeding in British Columbia
- Differences in the amortization to revenue of flow-through adjustments owing to customers period over period
- Lower pole-attachment revenue and a decrease in management fees resulting from lower third-party activity

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- A decrease in the interim allowed ROE, as discussed above. For the third quarter and year-to-date 2013 earnings were reduced by approximately $1 million and $3 million, respectively, as a result of the above regulatory decision.
- Lower pole-attachment revenue
- Higher effective income taxes, due to lower deductions for income tax purposes

Favourable

- Rate base growth, due to continued investment in energy infrastructure, including the acquisition of the City of Kelowna's electrical utility assets in March 2013
- Lower-than-expected finance charges

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Electricity Sales *(GWh)*	**950**	940	10	**4,180**	4,113	67
Revenue *($ millions)*	**105**	100	5	**434**	422	12
Earnings *($ millions)*	**8**	9	(1)	**39**	28	11

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable

- Growth in the number of customers
- Higher average consumption in the first half of 2013, reflecting the higher use of electric-versus-oil heating in new home construction and economic growth

Unfavourable

- Lower average consumption by large commercial customers in the third quarter of 2013

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The 1.1% and 1.6% increase in electricity sales for the quarter and year to date, respectively
- An increase in customer electricity rates, effective July 1, 2013, as reflected in the 2013/2014 General Rate Application ("GRA") decision received in April 2013. For further information on this decision refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- Higher effective income taxes, primarily due to the $2.5 million reversal of statute-barred Part VI.1 tax in the third quarter of 2012

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Lower storm-related costs due to the impact of Tropical Storm Leslie in September 2012

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- An approximate $13 million income tax recovery in the second quarter of 2013, due to the enactment of higher deductions associated with Part VI.1 tax, partially offset by the $2.5 million reversal of statute-barred Part VI.1 tax in the third quarter of 2012
- Rate base growth, due to continued investment in energy infrastructure
- Electricity sales growth

OTHER CANADIAN ELECTRIC UTILITIES [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Electricity Sales *(GWh)*	**580**	595	(15)	**1,809**	1,803	6
Revenue *($ millions)*	**97**	91	6	**280**	264	16
Earnings *($ millions)*	**7**	7	-	**22**	19	3

(1) Comprised of Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and Algoma Power.

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Unfavourable

- Lower average consumption by customers in Ontario reflecting more moderate temperatures, energy conservation and continued weak economic conditions in the region

Favourable

- Higher average consumption by residential customers on Prince Edward Island ("PEI"), due to cooler temperatures and an increase in the number of customers using electricity for home heating

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- Higher electricity sales on PEI combined with an increase in the basic component of customer rates at Maritime Electric, effective March 1, 2013
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario

Unfavourable

- Lower electricity sales in Ontario

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable

- An approximate $4 million income tax recovery at Maritime Electric in the second quarter of 2013, due to the enactment of higher deductions associated with Part VI.1 tax
- Electricity sales growth at Maritime Electric

Unfavourable

- Timing of the recognition of a regulatory rate of return adjustment at Maritime Electric in 2013 as compared to 2012

REGULATED ELECTRIC UTILITIES - CARIBBEAN (1)

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Average US:CDN Exchange Rate (2)	**1.04**	1.00	0.04	**1.02**	1.00	0.02
Electricity Sales *(GWh)*	**197**	197	-	**560**	547	13
Revenue *($ millions)*	**77**	72	5	**213**	202	11
Earnings *($ millions)*	**6**	6	-	**15**	15	-

(1) Comprised of Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 60% controlling interest and two wholly owned utilities in the Turks and Caicos Islands, FortisTCI Limited ("FortisTCI") and Turks and Caicos Utilities Limited ("TCU"), acquired in August 2012, (collectively "Fortis Turks and Caicos"). In June 2013 Atlantic Equipment & Power (Turks and Caicos) Ltd. was amalgamated with FortisTCI.

(2) The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar.

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable

- Increased electricity sales at Fortis Turks and Caicos due to approximately 5 GWh and 15 GWh of electricity sales in the third quarter and year-to-date 2013, respectively, at TCU, which was acquired in August 2012. Electricity sales at TCU in the third quarter of 2012 were approximately 2 GWh.

Unfavourable

- Higher rainfall experienced on Grand Cayman during the third quarter of 2013, which decreased air conditioning load

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- Approximately $3 million for the quarter and $4 million year to date of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar period over period
- The 2.4% increase in electricity sales year to date
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel
- A 1.8% increase in base customer electricity rates at Caribbean Utilities, effective June 1, 2013

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable

- A 1.8% increase in base customer electricity rates at Caribbean Utilities, effective June 1, 2013
- Decreased operating expenses at Caribbean Utilities in the first half of 2013, due to lower employee-related costs and maintenance costs

Unfavourable

- Overall higher depreciation expense, due to continued investment in energy infrastructure

NON-REGULATED - FORTIS GENERATION [1]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Energy Sales *(GWh)*	**104**	81	23	**242**	256	(14)
Revenue *($ millions)*	**12**	8	4	**24**	26	(2)
Earnings *($ millions)*	**8**	5	3	**35**	15	20

[1] Comprised of the financial results of non-regulated generation assets in Belize, Ontario, British Columbia and Upstate New York, with a combined generating capacity of 103 MW, mainly hydroelectric

Factors Contributing to Quarterly and Year-to-Date
Energy Sales Variances

Favourable
- Increased production in Belize in the third quarter of 2013, due to higher rainfall
- Increased production in Ontario and Upstate New York, due to higher rainfall and a generating unit in Upstate New York being returned to service for part of the second quarter of 2013, respectively, partially offset by lower production in British Columbia

Unfavourable
- Decreased production in Belize in the first half of 2013, due to lower rainfall

Factors Contributing to Quarterly and Year-to-Date
Revenue Variances

Favourable
- Increased production in Belize in the third quarter of 2013

Unfavourable
- Decreased production in Belize in the first half of 2013

Factors Contributing to Quarterly and Year-to-Date
Earnings Variances

Favourable
- Increased production in Belize in the third quarter of 2013
- An approximate $22 million after-tax extraordinary gain recognized in the first quarter of 2013 on the settlement of expropriation matters associated with the Exploits Partnership

Unfavourable
- Decreased production in Belize in the first half of 2013

NON-REGULATED - NON-UTILITY

The Non-Utility segment is comprised of Fortis Properties and Griffith. Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada. Non-regulated operations of CH Energy Group primarily consist of Griffith, which mainly supplies petroleum products and related services to approximately 65,000 customers in the Mid-Atlantic Region of the United States.

Financial Highlights (Unaudited) [1]						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2013**	2012	Variance	**2013**	2012	Variance
Revenue	**124**	65	59	**242**	181	61
Earnings	**6**	8	(2)	**15**	17	(2)

[1] Financial results of Griffith are from June 27, 2013, the date of acquisition. The reporting currency of Griffith is the US dollar.

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- Revenue of approximately $56 million for the third quarter and year-to-date 2013 at Griffith
- Increased revenue at Fortis Properties' Hospitality Division, mainly due to contribution from the StationPark All Suite Hotel, which was acquired in October 2012, and an increase in the average daily room rate in all regions
- Increased revenue at Fortis Properties' Real Estate Division, mainly due to the recovery of business occupancy tax from certain tenants in 2013

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- A net loss of approximately $2.5 million in the third quarter of 2013 at Griffith, which is comparable with the same quarter last year and reflects the impact of seasonality. A considerable portion of the sales volume for Griffith is derived directly or indirectly from usage in space heating and air conditioning and, as a result, seasonality impacts Griffith's earnings.

Favourable

- Improved performance at Fortis Properties' Hospitality Division, partially offset by increased depreciation due to capital additions and improvements

CORPORATE AND OTHER [(1)]

Financial Highlights (Unaudited) Periods Ended September 30 *($ millions)*	**Quarter** 2013	2012	Variance	**Year-to-Date** 2013	2012	Variance
Revenue	**6**	5	1	**19**	18	1
Operating Expenses	**2**	2	-	**8**	8	-
Depreciation and Amortization	**-**	-	-	**1**	1	-
Other Income (Expenses), Net	**(1)**	(3)	2	**(45)**	(11)	(34)
Finance Charges	**13**	13	-	**34**	36	(2)
Income Tax Recovery	**(5)**	(1)	(4)	**(38)**	(6)	(32)
	(5)	(12)	7	**(31)**	(32)	1
Preference Share Dividends	**16**	11	5	**44**	34	10
Net Corporate and Other Expenses	**(21)**	(23)	2	**(75)**	(66)	(9)

[(1)] Includes Fortis net Corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities, and the financial results of FHI's wholly owned subsidiary FortisBC Alternative Energy Services Inc. and FHI's 30% ownership interest in CustomerWorks Limited Partnership

Factors Contributing to Quarterly Net Corporate and Other Expenses Variance

Favourable

- A higher income tax recovery due to: (i) the release of income tax provisions of approximately $2 million in the third quarter of 2013; and (ii) approximately $1.5 million in income tax expense in the third quarter of 2012 associated with Part VI.1 tax. For further information on Part VI.1 tax, refer to the "Significant Items" section of this MD&A.
- Decreased other expenses mainly due to a $2 million foreign exchange loss in the third quarter of 2013, compared to $3 million in the third quarter of 2012, associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity
- Higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion was offset by higher interest on credit facility borrowings associated with financing the acquisition of CH Energy Group.

Unfavourable

- Higher preference share dividends due to: (i) the issuance of First Preference Shares, Series J in November 2012; (ii) the issuance of First Preference Shares, Series K in July 2013; and (iii) approximately $2 million of costs associated with the redemption of First Preference Shares, Series C in July 2013. The increase was partially offset by lower preference share dividends due to the redemption of First Preference Shares, Series C in July 2013.

Factors Contributing to Year-to-Date
Net Corporate and Other Expenses Variance

Unfavourable

- Increased other expenses primarily due to: (i) approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, in expenses associated with customer and community benefits offered by the Corporation to close the acquisition of CH Energy Group in June 2013; and (ii) approximately $8 million ($6 million after tax) in costs incurred in the second quarter of 2013 related to the acquisition of CH Energy Group, compared to approximately $8.5 million ($7.5 million after tax) year-to-date 2012. For additional information on the acquisition of CH Energy Group, refer to the "Significant Items" section of this MD&A. The above-noted increases were partially offset by a foreign exchange gain of approximately $3 million year-to-date 2013, associated with the translation of the Corporation's US dollar-denominated long-term other asset, as discussed above, compared to a foreign exchange loss of approximately $3 million year-to-date 2012.
- Higher preference share dividends, as discussed above for the quarter

Favourable

- A higher income tax recovery due to: (i) an approximate $6 million income tax recovery year-to-date 2013, due to the enactment of higher deductions associated with Part VI.1 tax compared to approximately $4.5 million in income tax expense year-to-date 2012 associated with Part VI.1 tax; and (ii) the release of income tax provisions of approximately $7 million year-to-date 2013
- Lower finance charges primarily due to higher capitalized interest associated with the financing of the construction of the Waneta Expansion, partially offset by higher interest on credit facility borrowings associated with financing the acquisition of CH Energy Group

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities year-to-date 2013 are summarized as follows.

NATURE OF REGULATION

		Allowed Common Equity	Allowed Returns (%)			Supportive Features
Regulated Utility	**Regulatory Authority**	**(%)**	**2011**	**2012**	**2013**	**Future or Historical Test Year Used to Set Customer Rates**
				ROE		COS/ROE
FEI	BCUC	38.5 (1)	9.50	9.50	8.75	FEI: Prior to January 1, 2010, 50%/50% sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40 (2)	10.00	10.00	9.25 (2)	
FEWI	BCUC	40 (2)	10.00	10.00	9.25 (2)	ROEs established by the BCUC - 2013 ROEs are under review
						Future Test Year
FortisBC Electric	BCUC	40 (2)	9.90	9.90	9.15 (2)	COS/ROE PBR mechanism for 2009 through 2011: 50%/50% sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC - 2013 ROE is under review
						Future Test Year
Central Hudson	PSC	48 (3)	10.00	10.00	10.00 (3)	COS/ROE Earnings sharing mechanism effective July 1, 2013: 50%/50% sharing of earnings above the allowed ROE up to 50 basis points above the allowed ROE; and 10%/90% sharing of earnings in excess of 50 basis points above the allowed ROE ROE established by PSC
						Future Test Year
FortisAlberta	Alberta Utilities Commission ("AUC")	41 (4)	8.75	8.75	8.75 (4)	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC - 2013 ROE is under review
						2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.38 +/- 50 bps	8.80 +/- 50 bps	8.80 +/- 50 bps	COS/ROE The allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields for 2011. ROE established by the PUB for 2012 through 2015
						Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission	40	9.75	9.75	9.75	COS/ROE
						Future Test Year

NATURE OF REGULATION (cont'd)

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2011	2012	2013	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		
FortisOntario	Ontario Energy Board ("OEB")					Canadian Niagara Power - COS/ROE
	Canadian Niagara Power	40	8.01	8.01	8.93 (5)	Algoma Power - COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") program
	Algoma Power	40	9.85	9.85	9.85 (5)	
	Franchise Agreement Cornwall Electric					Cornwall Electric - Price cap with commodity cost flow through
						Canadian Niagara Power - 2009 test year for 2011 and 2012; 2013 test year for 2013 Algoma Power - 2011 test year for 2011, 2012 and 2013
				ROA		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 - 9.75	7.25 - 9.25	6.50 - 8.50	Rate-cap adjustment mechanism based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings to the Government of the Turks and Caicos Islands	N/A	17.50 (6)	17.50 (6)	17.50 (6)	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the utilities may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Effective January 1, 2013. For 2011 and 2012, the allowed deemed equity component of the capital structure was 40%.
(2) Capital structures and allowed ROEs for 2013 are interim and are subject to change based on the outcome of the second phase of the GCOC Proceeding. The allowed ROEs for 2013 reflect the benchmark 8.75% allowed ROE for FEI, as set by the BCUC, and risk premiums associated with each of these utilities.
(3) Effective until June 30, 2015
(4) Capital structure and allowed ROE for 2013 are interim and are subject to change based on the outcome of a cost of capital proceeding.
(5) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 8.93% for 2013. This ROE is not applicable to the regulated electric utilities until they are scheduled to file full COS rate applications. As a result, the allowed ROE of 8.93% is not applicable to Algoma Power for 2013.
(6) Amount provided under licences as it relates to FortisTCI. Amount provided under licence for TCU is 15%. Achieved ROAs at the utilities were significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• Effective January 1, 2013, rates increased by approximately 1.6% for typical residential customers at FEI in the Lower Mainland, as a result of an increase in delivery rates in accordance with the BCUC's decision in April 2012 pertaining to the FortisBC Energy companies' 2012/2013 Revenue Requirements Application ("RRA"). Natural gas commodity rates effective January 1, 2013 remained unchanged for customers at FEI. • Effective July 1, 2013, due to an increase in natural gas commodity costs, rates for residential customers at FEI in the Lower Mainland increased by approximately 6.8%.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In February 2012 the BCUC approved FEI's amended application for a general tariff for the provision of compressed natural gas and liquefied natural gas ("LNG") refuelling services for transportation vehicles. FEI has received either permanent or interim rate approval for four refuelling projects. In June 2013 FEI received a decision on changing its LNG sales and dispensing service rate schedule from a pilot program to a permanent program. The decision did not approve the program as permanent, but extended the pilot program until the end of 2020, and set out the rate to be charged. In addition, FEI and FEVI received BCUC approval for rate treatment of expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") under the *Clean Energy Act* that was announced in May 2012. In May 2013 FEI filed an application for approval of its first refuelling station under the GGRR and in July 2013 the Company received approval of the rates to be charged to customers. In September 2013 FEVI filed an application for approval of its first refuelling station under the GGRR and a decision is expected in the fourth quarter of 2013. • In August 2011 FEI received a BCUC decision on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for natural gas-fuelled vehicles ("NGVs"). FEI had made these funds available to assist large customers in purchasing NGVs in lieu of vehicles fuelled by diesel. The decision determined that it was not appropriate to use EEC funds for the above-noted purpose and the BCUC requested that FEI provide further submissions to determine the prudency of the EEC incentives. In August 2012 an application was filed with the BCUC to review the prudency of the EEC incentives totalling approximately $6 million. A decision was received in April 2013 in which the BCUC determined that the EEC incentives for NGVs were prudently incurred and can be recovered from customers in rates. • During the first quarter of 2013, the BCUC approved the capital expenditures for the Telus Garden project at FortisBC Alternative Energy Services Inc. ("FAES"); however, approval of revisions to the rate design and rates is pending. In July 2013 the BCUC approved the capital expenditures for the Kelowna District Energy System project; however, approval of revisions to the rate design and rates is also pending. In May 2013 the BCUC initiated a process to review a proposal for a streamlined regulatory framework for thermal energy system utilities in British Columbia. The process is ongoing with a decision expected in the fourth quarter of 2013 or early 2014. In September 2013 FAES received interim rate approval for four smaller legacy projects. In October 2013 FAES applied for approval of a project under the proposed regulatory framework and a regulatory review process for this project has not yet been determined. • In April 2012 the FortisBC Energy companies applied to the BCUC for the necessary approvals to amalgamate the three utilities and implement common rates across the service territories served by the amalgamated entity, effective January 1, 2014. The BCUC issued its decision in February 2013 denying the request to implement common rates. The FortisBC Energy companies filed a leave to appeal the decision to the British Columbia Court of Appeal in March 2013 and filed an Application for Reconsideration with the BCUC in April 2013. In June 2013 the BCUC determined that the reconsideration application will be heard. The regulatory process to review the reconsideration application will be completed in November 2013 and a decision is expected in early 2014. • The public oral hearing for the first phase of a GCOC Proceeding to determine the allowed ROE and appropriate capital structure for FEI, the designated low-risk benchmark utility in British Columbia, occurred in December 2012. In May 2013 the BCUC issued its decision on the first phase of the GCOC Proceeding. Effective January 1, 2013, the decision set the ROE of the benchmark utility at 8.75%, compared to 9.50% for 2012, with a 38.5% equity component of capital structure, compared to 40% for 2012. The equity component of capital structure will remain in effect until December 31, 2015. Effective January 1, 2014 through December 31, 2015, the BCUC is also introducing an Automatic Adjustment Mechanism ("AAM") to set the ROE for the benchmark utility on an annual basis. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%. FEVI, FEWI and FortisBC Electric will have their allowed ROEs and capital structures determined in the second phase of the GCOC Proceeding. As a result of the BCUC's decision on the first phase of the GCOC Proceeding, which reduced the allowed ROE of the benchmark utility by 75 basis points, the interim allowed ROEs for FEVI, FEWI and FortisBC Electric decreased to 9.25%, 9.25% and 9.15%, respectively, effective January 1, 2013, while the deemed equity component of capital structures remained unchanged. The allowed ROEs and equity component of capital structures for FEVI, FEWI and FortisBC Electric could change further as a result of the outcome of the second phase of the GCOC Proceeding. In March 2013 the BCUC initiated the second phase of the GCOC Proceeding. The review process for the second phase is underway and a decision is expected in the first half of 2014.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In June 2013 FEI filed an application with the BCUC for a Multi-Year Performance-Based Ratemaking Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed in September 2013, the application assumes a 2014 forecast midyear rate base for FEI of approximately $2,789 million. The application also requests approval of a delivery rate increase for 2014 of approximately 1.4%, determined under a formula approach for operating and capital costs, and a continuation of this rate-setting methodology for a further four years. The regulatory process to review the application will continue throughout 2013 and 2014, with a decision expected mid-2014. • In September 2013 FEVI filed an application for Revenue Requirements and Rates for 2014, proposing to hold 2014 rates at existing levels. In October 2013 FEWI also filed an application for Revenue Requirements and Rates for 2014, proposing to hold 2014 rates at existing levels. Decisions on the applications are expected in early 2014.
FortisBC Electric	• Effective January 1, 2013, as approved by the BCUC in its August 2012 decision pertaining to FortisBC Electric's 2012/2013 RRA, customer electricity rates increased 4.2%. • In July 2012 FortisBC Electric filed its Advanced Metering Infrastructure ("AMI") Application, which was updated in early 2013. A regulatory review by the BCUC and various interveners concluded with an oral hearing in March 2013. In July 2013 the BCUC approved the AMI project for a total cost of approximately $51 million. The AMI project proposes to improve and modernize FortisBC Electric's grid by exchanging its manually read meters with advanced meters. In August 2013 the Company filed a Radio-Off Meter Option Application, which proposes that the incremental cost of opting-out of AMI be borne by customers who choose to opt-out. The BCUC is reviewing the application and a decision is expected in the first quarter of 2014. • In March 2013 the BCUC approved the acquisition by FortisBC Electric of the City of Kelowna's electrical utility assets and allowed for approximately $38 million of the $55 million purchase price to be included in FortisBC Electric's rate base, resulting in the recognition of approximately $14 million of goodwill and a $3 million deferred income tax asset. The transaction closed in March 2013, which allows FortisBC Electric to directly serve approximately 15,000 customers formerly served by the City. Prior to the acquisition, FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000. • In March 2012 the BCUC ordered a written hearing process to review the prudency of approximately $29 million in capital expenditures already incurred related to the Kettle Valley Distribution Source Project, which was substantially completed in 2009. In April 2013 the BCUC issued a decision approving substantially all of the $29 million to be included in rate base, effective from January 1, 2012. • In July 2013 FortisBC Electric filed an application with the BCUC for a Multi-Year Performance-Based Ratemaking Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed in October 2013, the application assumes a 2014 forecast midyear rate base of approximately $1,192 million. The application also requests approval of a basic customer rate increase for 2014 of approximately 3.3%, determined under a formula approach for operating and capital costs, and a continuation of this rate-setting methodology for a further four years. The regulatory process to review the application will continue throughout 2013 and 2014, with a decision expected mid-2014.
Central Hudson	• There were no material regulatory decisions and applications at Central Hudson in the third quarter of 2013. For further information on regulation at Central Hudson, refer to the "Regulated Gas & Electric Utility – United States" section of this MD&A.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta	• In September 2012 the AUC issued a generic PBR Decision outlining the PBR framework applicable to distribution utilities in Alberta, including FortisAlberta, for a five-year term, which commenced January 1, 2013. In the PBR Decision, a formula that estimates inflation annually and assumes productivity improvements is to be used by the distribution utilities to determine customer rates on an annual basis. The PBR framework also includes mechanisms for the recovery or settlement of items determined to flow through directly to customers and the recovery of costs related to capital expenditures that are not being recovered through the inflationary factor of the formula. The AUC also approved: (i) a Z factor permitting an application for recovery of costs related to significant unforeseen events; (ii) a PBR re-opener mechanism permitting an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan; and (iii) an ROE efficiency carry-over mechanism permitting an efficiency incentive by allowing the utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of the term. The PBR formula does, however, raise some concern and uncertainty for FortisAlberta regarding the treatment of certain capital expenditures. While the PBR Decision did provide for a capital tracker mechanism for the recovery of costs related to certain capital expenditures, FortisAlberta sought further clarification regarding this mechanism in a Review and Variance ("R&V") Application and a Capital Tracker Application and sought leave to appeal the issue with the Alberta Court of Appeal. • In March 2013 the AUC issued a decision denying the R&V Application. FortisAlberta has filed a leave to appeal the decision on similar grounds as the leave to appeal the PBR Decision. Both appeals have been adjourned pending further determinations in outstanding PBR-related proceedings. • In January 2013 FortisAlberta filed a Phase II Distribution Tariff Application ("Phase II DTA"), which proposed rates by customer class based on a cost allocation study and requested that the 2012 interim distribution rates by customer class be made final for 2012 and 2013, subject to further adjustments as a result of the PBR decision, and be applied to rates effective January 1, 2014. The Phase II DTA proceeding is complete and a decision is expected in the fourth quarter of 2013. The outcome of the proceeding is not expected to have a material impact on FortisAlberta's 2013 financial results. • In March 2013 the AUC issued an interim decision regarding the Compliance Applications filed by the distribution utilities in Alberta. The interim decision approved a combined inflation and productivity factor of 1.71%, certain adjustments to the Company's going-in rates, including Y factor amounts and a K factor placeholder equal to 60% of the applied for capital tracker amount. For FortisAlberta, the AUC approved approximately $14.5 million of the $24 million in revenue requested in the utility's 2013 Capital Tracker Application. The decision resulted in an interim increase in FortisAlberta's distribution rates of approximately 4%, effective January 1, 2013, with collection from customers commencing April 1, 2013. A final decision on the Compliance Application was received in July 2013 directing the Company to continue to use interim rates until all remaining 2013 placeholders have been determined. A hearing on the Capital Tracker Application was held in June and July 2013. A decision is expected in the fourth quarter of 2013 and could result in further adjustments to FortisAlberta's 2013 distribution rates. When a decision is received, the impact of any adjustment to the K factor placeholder will be reflected in revenue. • In September 2013 FortisAlberta filed its 2014 Annual Rates Filing. The rates and riders, proposed to be effective on an interim basis for January 1, 2014, include a 5.36% increase to the distribution component of customer rates. This increase reflects a combined inflation and productivity factor of 1.59%, a K factor based on the capital tracker placeholder of 60% applied to the capital expenditure forecast for 2014, and a net refund of Y factor balances. A decision on this filing is expected in the fourth quarter of 2013. • In October 2012 the AUC initiated a 2013 GCOC Proceeding to establish the final allowed ROE for 2013 and determine whether a formulaic ROE automatic adjustment mechanism should be re-established. In November 2012 the 2013 GCOC Proceeding was suspended until other regulatory matters were resolved. In April 2013 the AUC recommenced the 2013 GCOC Proceeding to set the allowed ROE and capital structure for distribution utilities in Alberta for 2013, as well as the allowed ROE for 2014. In addition, an interim allowed ROE for 2015 will be established. In this proceeding the AUC may consider the possibility of re-establishing a formula-based approach to setting annual ROE. The process for the 2013 GCOC Proceeding commenced in the second quarter of 2013 and a hearing is scheduled for early 2014. The expected outcome of this proceeding is currently unknown.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In the PBR Decision, the AUC determined that annual Capital Tracker Applications will be filed in March for projects planned for the subsequent year. Accordingly, FortisAlberta would normally have applied for its 2014 Capital Tracker in March 2013. However, given that a decision on the 2013 Capital Tracker Application is outstanding, the AUC determined that the filing of the 2014 Capital Tracker Application would be delayed until after a decision on the 2013 application is issued. With a decision on the 2013 Capital Tracker Application expected in the fourth quarter of 2013, it is expected that both the 2014 and 2015 Capital Tracker Applications will be filed in the first quarter of 2014. • In its 2011 GCOC Decision, the AUC made statements regarding cost responsibility for stranded assets, which FortisAlberta and other utilities challenged as being incorrectly made. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and, to an extent, also conflicts directly with the *Electric Utilities Act (Alberta).* As a result, FortisAlberta, together with other Alberta utilities, filed an R&V Application with the AUC. In June 2012 the AUC decided it would not permit an R&V of the decision in question but would examine the issue in the Utility Asset Disposition ("UAD") Proceeding, which was reinitiated in November 2012. FortisAlberta and the other Alberta utilities had also sought leave to appeal the stranded asset pronouncements with the Alberta Court of Appeal and temporarily adjourned that court process pending the AUC's follow-up proceeding. Any decision by the AUC regarding the treatment of stranded assets cannot alter a utility's right to a reasonable opportunity to recover prudent COS and earn a fair ROE. The UAD proceeding also seeks to clarify the regulatory treatment of the disposition of assets that were formally used in the provision of regulated services. The UAD proceeding has closed and a decision is expected in the fourth quarter of 2013. The outcome of this proceeding is currently unknown.
Newfoundland Power	• In April 2013 the PUB issued its decision related to Newfoundland Power's 2013/2014 GRA, which was filed in September 2012, to establish the Company's cost of capital for rate-making purposes. In its decision, the PUB ordered that the allowed ROE and common equity component of capital structure remain at 8.8% and 45%, respectively, for 2013 through 2015. The PUB also ordered: (i) the recognition of pension expense for regulatory purposes in accordance with US GAAP and the related regulatory asset to be recovered from customers over 15 years; (ii) a decrease in the overall composite depreciation rate to 3.42% from 3.47%; (iii) the deferral of annual customer energy conservation program costs to be recovered from customers over the subsequent seven-year period; and (iv) the approval of various regulatory amortizations over a three-year period, including cost-recovery deferrals recognized in 2011 and 2012, costs associated with the GRA and the December 31, 2011 balance in the Weather Normalization Account. The impact of the decision resulted in an overall average increase in customer electricity rates of approximately 4.8% effective July 1, 2013 and the deferral of approximately $4 million of costs incurred in 2013 but not recovered from customers, due to the timing of collection in customer rates. The cumulative impact of the decision was recorded in the second quarter of 2013, when the decision was received. Newfoundland Power is required to file its GRA for 2016 on or before June 1, 2015. • Effective July 1, 2013, the PUB approved an overall average decrease in Newfoundland Power's customer electricity rates of approximately 3.1% to reflect the combined impact of the annual operation of Newfoundland Power's Rate Stabilization Account ("RSA") and the above-noted GRA decision. Through the annual operation of Newfoundland Hydro's Rate Stabilization Plan, variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to customers through the operation of the Company's RSA. As a result of a decrease in the forecast cost of oil to be used to generate electricity at Newfoundland Hydro, customer electricity rates decreased approximately 7.9% effective July 1, 2013. The RSA also captures variances in certain of Newfoundland Power's costs, such as pension and energy supply costs. The decrease in customer rates as a result of the operation of the RSA is not expected to impact Newfoundland Power's earnings in 2013. • In September 2013 the PUB approved Newfoundland Power's 2014 Capital Expenditure Plan totalling approximately $85 million, before customer contributions.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Maritime Electric	• In December 2012 the *Electric Power (Energy Accord Continuation) Amendment Act* (*"Accord Continuation Act")* was enacted, which sets out the inputs, rates and other terms for the continuation of the PEI Energy Accord for an additional three years covering the period March 1, 2013 through February 29, 2016. Under the terms of the *Accord Continuation Act,* Maritime Electric received, in March 2013, proceeds of approximately $47 million from the Government of PEI upon its assumption of Maritime Electric's $47 million regulatory asset related to certain deferred incremental replacement energy costs during the refurbishment of Point Lepreau. Over the above-noted three-year period, increases in electricity costs for a typical residential customer have been set at 2.2%, effective March 1 annually, and Maritime Electric's allowed ROE has been capped at 9.75% each year. The resulting customer rate increases are primarily due to higher COS and the collection from customers by Maritime Electric, acting as an agent on behalf of the Government of PEI, of Point Lepreau-related costs assumed by the Government of PEI. The proceeds were used by Maritime Electric to repay short-term borrowings, to pay a special dividend to Fortis to maintain the utility's capital structure and to finance its capital expenditure program. • In July 2013 Maritime Electric filed its 2014 Capital Budget Application totalling approximately $28 million, before customer contributions.
FortisOntario	• Effective January 1, 2013, residential customer rates in Fort Erie, Gananoque and Port Colborne increased by an average of 6.8%, 5.9% and 7.4%, respectively. The rate increases were the result of the OEB's decision pertaining to FortisOntario's 2013 COS Application using a 2013 forward test year and the recovery of smart meter costs and stranded assets related to conventional meters and reflect an allowed ROE of 8.93%. • In March 2013 the OEB issued its decision on Algoma Power's Third-Generation Incentive-Regulation Mechanism ("IRM") Application for customer electricity distribution rates and smart meter cost recovery, effective January 1, 2013, resulting in an overall increase in residential and commercial customer distribution rates of 3.75%. Residential and commercial customer distribution rates are adjusted by the average increase in customer rates of all other distributor rate changes in Ontario in the most recent rate year. The difference in the recovery of COS in residential and commercial customer distribution rates and the revenue requirement is compensated from RRRP program funding. Recovery of smart meter costs allocated to residential customers will also be recovered from RRRP program funding as ordered by the OEB. Total RRRP program funding for 2013 is expected to be approximately $12 million. • In August 2013 Canadian Niagara Power and Algoma Power filed applications with the OEB requesting approval for customer electricity distribution rates, effective January 1, 2014, based on the Fourth-Generation IRM. Under the Fourth-Generation IRM, which is effective for utilities in Ontario on or after January 1, 2014, in non-rebasing years customer electricity distribution rates are set using inflationary factors less a productivity factor.
Caribbean Utilities	• In June 2013 the ERA approved Caribbean Utilities' 2013-2017 Capital Investment Plan for US$123 million related to non-generation installation capital expenditures. Capital expenditures relating to additional generation installation are subject to ERA approval through a competitive bid process. • A Certificate of Need was filed with the ERA by Caribbean Utilities in November 2011, due to the upcoming retirements of some of the Company's generating units due to begin in mid-2014. In March 2012 proposals for the installation of new generation units from six qualified bidders, including Caribbean Utilities, was requested by the ERA and the Company's proposal was submitted in July 2012. In February 2013 the ERA awarded the bid to develop, install and operate two new 18-MW generation units to a third party. In April 2013 the ERA announced that it would be engaging an independent party to conduct an investigation of irregularities in the bid process. In July 2013 the ERA announced that it has cancelled the solicitation process as a result of unavoidable and unforeseen delays. The need for additional firm generating capacity for mid-2014 remains. In light of the ERA's decision to cancel the solicitation process, Caribbean Utilities will explore all cost-effective options with the ERA to ensure that there is sufficient installed generating capacity to serve the needs of its customers until the firm capacity needs can be met. • Effective June 1, 2013, following review and approval by the ERA, Caribbean Utilities' base customer electricity rates increased by 1.8% as a result of changes in the applicable consumer price indices and the utility's applicable targeted allowed ROA for the 2013 rate adjustment.
Fortis Turks and Caicos	• In March 2013 the Fortis Turks and Caicos utilities submitted their 2012 annual regulatory filings outlining performance in 2012. Included in the filings were the calculations, in accordance with the utilities' licences, of rate base of US$195 million for 2012 and cumulative shortfall in achieving allowable profits of US$105 million as at December 31, 2012.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheet between September 30, 2013 and December 31, 2012.

Significant Changes in the Consolidated Balance Sheet (Unaudited) between September 30, 2013 and December 31, 2012

Balance Sheet Account	Increase Due to CH Energy Group *($ millions)*	Other Increase/ (Decrease) *($ millions)*	Explanation for Other Increase/(Decrease)
Accounts receivable	110	(174)	The decrease was primarily due to the impact of a seasonal decrease in sales at the FortisBC Energy companies and Newfoundland Power.
Regulatory assets – current and long-term	253	18	The increase was mainly due to higher regulatory deferred income taxes and the deferral of various other costs, as permitted by the regulators, mainly at the FortisBC Energy companies and FortisAlberta. The above increases were partially offset by proceeds of approximately $47 million received from the Government of PEI in March 2013 upon its assumption of Maritime Electric's replacement energy deferral associated with Point Lepreau, and the change in the deferral of the fair market value of natural gas commodity derivatives at the FortisBC Energy companies.
Utility capital assets	1,278	449	The increase primarily related to: (i) utility capital expenditures; (ii) the acquisition of the City of Kelowna's electrical utility assets by FortisBC Electric; and (iii) the impact of foreign exchange on the translation of US dollar-denominated utility capital assets. The above increases were partially offset by depreciation and customer contributions.
Goodwill	476	20	The increase primarily related to $14 million in goodwill associated with the acquisition of the City of Kelowna's electrical utility assets by FortisBC Electric.
Accounts payable and other current liabilities	102	(221)	The decrease was mainly due to: (i) lower accounts payable associated with transmission-connected projects and the timing of Alberta Electric System Operator payments for 2012 transmission costs at FortisAlberta; (ii) the timing of payments for trade accounts payable and other taxes payable at the FortisBC Energy companies; (iii) the change in the fair market value of natural gas commodity derivatives at the FortisBC Energy companies; (iv) the enactment of higher deductions associated with Part VI.1 tax, resulting in the reversal of approximately $23 million in income tax liabilities; and (v) lower amounts owing for purchased power at Newfoundland Power associated with seasonality of operations. The decrease was partially offset by an increase in 2013 transmission costs payable at FortisAlberta.
Regulatory liabilities – current and long-term	158	1	The increase in regulatory liabilities was not significant.

CONSOLIDATED FINANCIAL POSITION (cont'd)

Significant Changes in the Consolidated Balance Sheet (Unaudited) between September 30, 2013 and December 31, 2012 (cont'd)

Balance Sheet Account	**Increase Due to CH Energy Group** *($ millions)*	**Other Increase/ (Decrease)** *($ millions)*	**Explanation for Other Increase/(Decrease)**
Long-term debt (including current portion)	533	686	The increase was driven by: (i) higher committed credit facility borrowings at the Corporation to finance a portion of the acquisition of CH Energy Group; (ii) the issue of $150 million unsecured debentures at FortisAlberta; (iii) higher committed credit facility borrowings at FortisBC Electric, mainly associated with the acquisition of the City of Kelowna's electrical utility assets; (iv) the issue of US$50 million unsecured debentures at Caribbean Utilities; and (v) the impact of foreign exchange on the translation of US-dollar denominated debt. The above-noted increases were partially offset by regularly scheduled debt repayments.
Deferred income tax liabilities – current and long-term	271	90	The increase was driven by tax timing differences related mainly to capital expenditures at the regulated utilities.
Other Liabilities	185	(15)	The decrease in other liabilities was not significant.
Shareholders' equity (before non-controlling interests)	-	817	The increase primarily related to: (i) the conversion of Subscription Receipts into common shares in June 2013 for net after-tax proceeds of $567 million to finance a portion of the acquisition of CH Energy Group; (ii) the issuance of First Preference Shares, Series K in July 2013 for net after-tax proceeds of $244 million; (iii) net earnings attributable to common equity shareholders for the nine months ended September 30, 2013, less dividends declared on common shares; and (iv) the issuance of common shares under the Corporation's Dividend Reinvestment Plan. The above-noted increases were partially offset by the redemption of First Preference Shares, Series C in July 2013 for $125 million.
Non-controlling interests	-	45	The increase was driven by advances from the 49% non-controlling interests in the Waneta Expansion Limited Partnership ("Waneta Partnership").

LIQUIDITY AND CAPITAL RESOURCES

The table below outlines the Corporation's sources and uses of cash for the three and nine months ended September 30, 2013, as compared to the same periods in 2012, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2013**	2012	Variance	**2013**	2012	Variance
Cash, Beginning of Period	**267**	231	36	**154**	87	67
Cash Provided by (Used in):						
Operating Activities	**102**	221	(119)	**680**	804	(124)
Investing Activities	**(249)**	(277)	28	**(1,834)**	(761)	(1,073)
Financing Activities	**35**	(28)	63	**1,155**	17	1,138
Cash, End of Period	**155**	147	8	**155**	147	8

Operating Activities: Cash flow from operating activities was $119 million lower for the quarter and $124 million lower year to date compared to the same periods last year. The decreases were primarily due to unfavourable changes in working capital at FortisAlberta and unfavourable changes in long-term regulatory deferral accounts at the FortisBC Energy companies. The decreases were partially offset by: (i) higher earnings and the collection from customers of regulator-approved increases in depreciation and amortization; (ii) favourable changes in working capital at Maritime Electric in the first quarter of 2013; and (iii) cash proceeds received in the second quarter of 2013 on the settlement of the expropriation matters associated with the Exploits Partnership.

Investing Activities: Cash used in investing activities was $28 million lower quarter over quarter, primarily due to lower capital expenditures related to the non-regulated Waneta Expansion and at FortisAlberta and the FortisBC Energy companies. The decrease was partially offset by capital spending at Central Hudson in the third quarter of 2013.

Cash used in investing activities was $1,073 million higher year to date compared to the same period last year. The increase was primarily due to the acquisition of CH Energy Group in June 2013 for a net cash purchase price of $1,019 million and FortisBC Electric's acquisition of electrical utility assets of the City of Kelowna in March 2013 for approximately $55 million. Higher capital expenditures at the regulated utilities, including capital spending at Central Hudson in the third quarter of 2013, and Fortis Properties was partially offset by lower capital expenditures related to the non-regulated Waneta Expansion.

Financing Activities: Cash provided by financing activities was $35 million for the third quarter compared to cash used in financing activities of $28 million for the same period last year. The change quarter over quarter was primarily due to the issuance of preference shares in July 2013 and higher proceeds from long-term debt, partially offset by higher repayments under committed credit facilities classified as long term and the redemption of preference shares in July 2013.

Cash provided by financing activities was $1,138 million higher year to date compared to the same period last year. The increase was primarily due to the issuance of common shares and borrowings under the Corporation's committed credit facility in connection with the acquisition of CH Energy Group, combined with the issuance of preference shares in July 2013 and higher proceeds from long-term debt. The increase was partially offset by the redemption of preference shares in July 2013 and lower advances from non-controlling interests.

In May 2013 Caribbean Utilities issued 15-year US$10 million 3.34% and 20-year US$40 million 3.54% senior unsecured notes. The proceeds were used to repay short-term borrowings and to finance capital expenditures.

In September 2013 FortisAlberta issued 30-year $150 million 4.85% unsecured debentures. The net proceeds are being used to repay credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

Repayments of long-term debt and capital lease and finance obligations and net (repayments) borrowings under committed credit facilities for the quarter and year to date compared to the same periods last year are summarized in the following tables.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2013**	2012	Variance	**2013**	2012	Variance
FortisBC Energy Companies	**(2)**	-	(2)	**(28)**	(18)	(10)
Caribbean Utilities	**-**	-	-	**(17)**	(13)	(4)
Fortis Properties	**(1)**	-	(1)	**(21)**	(24)	3
Other	**(2)**	-	(2)	**(4)**	(2)	(2)
Total	**(5)**	-	(5)	**(70)**	(57)	(13)

Net (Repayments) Borrowings Under Committed Credit Facilities (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2013**	2012	Variance	**2013**	2012	Variance
FortisAlberta	**(94)**	(22)	(72)	**-**	(13)	13
FortisBC Electric	**11**	(17)	28	**44**	(9)	53
Newfoundland Power	**(20)**	(20)	-	**2**	8	(6)
Corporate	**(84)**	50	(134)	**465**	235	230
Total	**(187)**	(9)	(178)	**511**	221	290

Borrowings under credit facilities by the utilities are primarily in support of their capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility. The borrowings under the Corporation's committed credit facility in 2013 were incurred to finance a portion of the acquisition of CH Energy Group, to support the construction of the Waneta Expansion and to finance an equity injection into FortisAlberta in support of energy infrastructure investment.

Advances from non-controlling interests in the Waneta Partnership of approximately $42 million were received in the first half of 2013 to finance capital spending related to the Waneta Expansion, compared to $14 million and $70 million received during the third quarter and year-to-date periods in 2012, respectively. In January 2012 advances of approximately $12 million were received from two First Nations bands, representing their 15% equity investment in the LNG storage facility on Vancouver Island.

Proceeds from the issuance of common shares were $592 million year-to-date 2013, compared to $12 million for the same period last year. The increase was primarily due to the issuance of 18.5 million common shares in June 2013, as a result of the conversion of the Subscription Receipts on closing of the CH Energy Group acquisition, for proceeds of approximately $567 million, net of after-tax expenses. The increase also reflected a higher number of common shares issued under the Corporation's dividend reinvestment and employee share purchase plans.

In July 2013 Fortis issued 10 million First Preference Shares, Series K for gross proceeds of $250 million. The proceeds were used to redeem all of the Corporation's First Preference Shares, Series C in July 2013 for $125 million, to repay a portion of credit facility borrowings, and for other general corporate purposes.

Common share dividends paid in the third quarter of 2013 were $49 million, net of $17 million of dividends reinvested, compared to $42 million, net of $15 million of dividends reinvested, paid in the same quarter of 2012. Common share dividends paid year-to-date 2013 were $134 million, net of $51 million of dividends reinvested, compared to $128 million, net of $43 million of dividends reinvested, paid year-to-date 2012. The dividend paid per common share for each of the first, second and third quarters of 2013 was $0.31 compared to $0.30 for each of the first, second and third quarters of 2012. The weighted average number of common shares outstanding for the third quarter and year to date was 212.0 million and 199.1 million, respectively, compared to 190.2 million and 189.6 million, respectively, for the same periods in 2012.

CONTRACTUAL OBLIGATIONS

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at September 30, 2013, are outlined in the following table. A detailed description of the nature of the obligations is provided in the 2012 Annual MD&A and below, where applicable.

Contractual Obligations (Unaudited) **As at September 30, 2013** *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**7,119**	369	605	377	58	608	5,102
Government loan obligations	**15**	-	10	5	-	-	-
Capital lease and finance obligations	**2,551**	47	47	49	49	50	2,309
Interest obligations on long-term debt	**7,112**	385	357	328	308	298	5,436
Gas purchase contract obligations (1)	**405**	284	51	19	16	12	23
Power purchase obligations:							
Central Hudson (2)	**42**	20	4	3	3	3	9
FortisBC Electric	**35**	14	11	6	3	1	-
FortisOntario	**320**	46	50	51	52	53	68
Maritime Electric	**111**	40	40	17	1	1	12
Capital cost (3)	**542**	20	19	21	19	21	442
Construction and maintenance projects (4)	**119**	61	33	14	4	3	4
Operating lease obligations	**21**	4	4	3	3	3	4
Waneta Partnership promissory note	**72**	-	-	-	-	-	72
Joint-use asset and shared service agreements	**61**	3	3	3	3	3	46
Defined benefit pension funding contributions	**57**	23	15	12	4	-	3
Performance Share Unit Plan obligations	**8**	2	2	4	-	-	-
Other	**16**	12	-	-	-	-	4
Total	**18,606**	1,330	1,251	912	523	1,056	13,534

(1) Gas purchase contract obligations at the FortisBC Energy companies are based on index prices as at September 30, 2013. Gas purchase contract obligations at Central Hudson are based on tariff rates as at September 30, 2013.

(2) Central Hudson has entered into agreements with Entergy Nuclear Power Marketing, LLC to purchase electricity, and not capacity, on a unit-contingent basis at defined prices from January 1, 2011 through December 31, 2013. Central Hudson must also acquire sufficient peak load capacity to meet the peak load requirements of its full-service customers. This capacity requirement is met through contracts with capacity providers, purchases from the NYISO capacity market and the Company's own generating capacity.

(3) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the facility returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life an additional 27 years and, as a result, the total estimated capital cost obligation has increased approximately $96 million from that disclosed in the 2012 Annual MD&A.

(4) Central Hudson has various purchase commitments and contracts related to ongoing projects and operating activities.

Other contractual obligations, which are not reflected in the above table, did not materially change from those disclosed in the 2012 Annual MD&A, except as follows.

In May 2013 FortisBC Electric entered into a new Power Purchase Agreement ("PPA") with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013. This new PPA does not change the basic parameters of the BC Hydro PPA, which expired on September 30, 2013. An executed version of the PPA was submitted by BC Hydro to the BCUC in May 2013 and is pending regulatory approval. In the interim period until the new PPA is approved by the BCUC, FortisBC Electric and BC Hydro have agreed to continue under the terms of the expired BC Hydro PPA. Power purchases in the interim are approved for recovery in customer rates. The power purchases from the new PPA are expected to be recovered in customer rates.

For a discussion of the nature and amount of the Corporation's consolidated capital expenditure program, that is not included in the preceding Contractual Obligations table, refer to the "Capital Expenditure Program" section of this MD&A.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 45% equity, including preference shares, and 55% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure (Unaudited)	**As at**			
	September 30, 2013		December 31, 2012	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash)	**7,503**	**55.9**	6,317	55.3
Preference shares	**1,229**	**9.2**	1,108	9.7
Common shareholders' equity	**4,688**	**34.9**	3,992	35.0
Total (1)	**13,420**	**100.0**	11,417	100.0

(1) Excludes amounts related to non-controlling interests

The change in the capital structure was primarily due to the financing of the acquisition of CH Energy Group, including: (i) the conversion of Subscription Receipts into common shares for $567 million, net of after-tax expenses; (ii) debt assumed upon acquisition; and (iii) higher borrowings under the Corporation's committed credit facility, to initially finance the remaining portion of the acquisition. The capital structure was also impacted by: (i) an increase in total debt, mainly in support of energy infrastructure investment; (ii) the issuance of First Preference Shares, Series K, partially offset by the redemption of First Preference Shares, Series C; (iii) net earnings attributable to common equity shareholders for the nine months ended September 30, 2013, less dividends declared on common shares; and (iv) the issuance of common shares under the Corporation's Dividend Reinvestment Plan.

Excluding capital lease and finance obligations, the Corporation's capital structure as at September 30, 2013 was 54.4% debt, 9.5% preference shares and 36.1% common shareholders' equity (December 31, 2012 - 53.6% debt, 10.1% preference shares and 36.3% common shareholders' equity).

CREDIT RATINGS

The Corporation's credit ratings are as follows:

Standard & Poor's ("S&P")	A- (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

In February 2013 S&P and DBRS affirmed the Corporation's debt credit ratings. The above-noted credit ratings reflect the Corporation's business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. The credit ratings also reflect the Corporation's financing of the acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget.

CAPITAL EXPENDITURE PROGRAM

A breakdown of the $809 million in gross consolidated capital expenditures by segment year-to-date 2013 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year-to-Date September 30, 2013
($ millions)

FortisBC Energy Companies	Central Hudson	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	**Total Regulated Utilities**	**Non-Regulated - Fortis Generation**	**Non-Regulated - Non-Utility**	**Total**
142	28	306	58	63	40	35	**672**	**101**	**36**	**809**

(1) Relates to cash payments to acquire or construct utility and non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes capitalized depreciation and amortization and non-cash equity component of AFUDC.

Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from those forecast.

Gross consolidated capital expenditures for 2013 are forecast to be approximately $1.2 billion. This represents a decrease of approximately $150 million from the original 2013 forecast disclosed in the 2012 Annual MD&A. The decrease is primarily due to the non-regulated Waneta Expansion, FortisBC Electric and FAES, partially offset by Central Hudson.

Lower forecast capital expenditures related to the Waneta Expansion for 2013 are primarily due to the timing of payments. Capital expenditures at FortisBC Electric are expected to be lower than the original forecast for 2013 as a result of labour disruptions. For further information on labour relations refer to the "Business Risk Management" section of this MD&A. Due to the uncertainty of the timing of alternative energy projects at FAES, capital expenditures for 2013 are delayed and are expected to be lower than the original forecast. Capital expenditures for 2013 now include approximately $59 million forecast at Central Hudson from the date of acquisition.

Construction of the $900 million Waneta Expansion is ongoing, with an additional $98 million invested year-to-date 2013. Approximately $534 million has been invested in the Waneta Expansion since construction began late in 2010. Key construction activities year-to-date 2013 include the ongoing civil construction of the powerhouse and intake, installation of the turbine components, installation of ancillary mechanical and electrical powerhouse services, and most notably, the encapsulating of the scrollcase in concrete. During the third quarter, the generator step-up transformers were received onsite for assembly. The key offsite activity in the third quarter of 2013 was the successful completion of the manufacturing of the first turbine runner and turbine operating mechanism.

Over the five-year period 2013 through 2017, gross consolidated capital expenditures are expected to be approximately $6 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 53% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 21% at Canadian Regulated Gas Utilities; 11% at Central Hudson; 4% at Caribbean Regulated Electric Utilities; and the remaining 11% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 36% to meet customer growth, 41% for sustaining capital expenditures, and 23% for facilities, equipment, vehicles, information technology and other assets.

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends.

As at September 30, 2013, management expects consolidated long-term debt maturities and repayments to average approximately $335 million annually over the next five years, excluding borrowings under the Corporation's committed credit facility which were subsequently replaced with long-term financing. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

In May 2012 Fortis filed a short-form base shelf prospectus under which Fortis may offer, from time to time during the 25-month period from May 10, 2012, by way of a prospectus supplement, common shares, preference shares, subscription receipts and/or unsecured debentures in the aggregate amount of up to $1.3 billion (or the equivalent in US dollars or other currencies). The base shelf prospectus provides the Corporation with flexibility to access securities markets in a timely manner.

Through prospectus supplements filed under its base shelf prospectus, Fortis offered and sold: (i) approximately $601 million of Subscription Receipts in June 2012 (refer to the "Significant Items" section in this MD&A); (ii) $200 million First Preference Shares, Series J in November 2012; and (iii) $250 million First Preference Shares, Series K in July 2013 (refer to the "Significant Items" section in this MD&A). The remaining amount available under the base shelf prospectus is approximately $250 million.

In July 2013 FortisBC Electric filed a short-form base shelf prospectus to establish a Medium-Term Note ("MTN") Debentures Program and entered into a dealer agreement with certain affiliates of a group of Canadian Chartered Banks. Upon filing the shelf prospectus, the Company may, from time to time during the 25-month life of the base shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $300 million. The establishment of the MTN Debentures Program has been approved by the BCUC.

In October 2013 FortisAlberta filed a short-form base shelf prospectus under which the Company may, from time to time during the 25-month life of the base shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $500 million.

Fortis and its subsidiaries were compliant with debt covenants as at September 30, 2013 and are expected to remain compliant throughout 2013.

CREDIT FACILITIES

As at September 30, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion, of which $1.9 billion was unused, including $490 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.6 billion of the total credit facilities are committed facilities with maturities ranging from 2014 through 2018.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities (Unaudited)				**As at**	
($ millions)	Regulated Utilities	Non-Regulated	Corporate and Other	**September 30, 2013**	December 31, 2012
Total credit facilities	1,539	115	1,030	**2,684**	2,460
Credit facilities utilized:					
Short-term borrowings	(111)	-	-	**(111)**	(136)
Long-term debt (including current portion)	(123)	-	(509)	**(632)**	(150)
Letters of credit outstanding	(65)	-	(1)	**(66)**	(67)
Credit facilities unused	1,240	115	520	**1,875**	2,107

As at September 30, 2013 and December 31, 2012, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In January 2013 FEVI's $20 million unsecured committed non-revolving credit facility matured and was not replaced.

In April 2013 FortisBC Electric renegotiated and amended its credit facility agreement, resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2016 and $50 million now maturing in May 2014. The amended credit facility agreement contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2013 FHI extended its $30 million unsecured committed revolving credit facility to mature in May 2014 from May 2013.

In May 2013 FortisOntario extended its $30 million unsecured revolving credit facility to mature in June 2014 from June 2013.

In June 2013 Fortis Turks and Caicos entered into new short-term unsecured demand credit facilities for US$21 million ($22 million), replacing its previous US$21 million ($22 million) facilities. The new facilities are comprised of a revolving operating credit facility of US$12 million ($12 million) and a US$9 million ($9 million) emergency standby loan. The facilities mature in June 2014, with an option to renew annually. The new credit facilities reflect a decrease in pricing but otherwise contain terms and conditions substantially similar to the previous facilities.

In July 2013 FEI, FEVI and FortisAlberta amended their $500 million, $200 million and $250 million committed revolving credit facilities, resulting in extensions to the maturity dates to August 2015, December 2015 and August 2018, respectively, from August 2014, December 2013 and August 2016, respectively. The new agreements contain substantially similar terms and conditions as the previous credit facility agreements.

In August 2013 the Corporation extended its $1 billion committed revolving corporate credit facility to mature in July 2018 from July 2015.

As at September 30, 2013, CH Energy Group had a US$100 million ($103 million) unsecured revolving credit facility maturing in October 2015, and Central Hudson had a US$150 million ($155 million) unsecured committed revolving credit facility maturing in October 2016.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments (Unaudited)	**As at**			
	September 30, 2013		December 31, 2012	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**49**	**50**	47	51
Long-term debt, including current portion	**7,119**	**8,029**	5,900	7,338

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) by obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The Financial Instruments table above excludes the long-term other asset associated with the Corporation's expropriated investment in Belize Electricity. Due to uncertainty in the ultimate amount and ability of the Government of Belize ("GOB") to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the book value of the expropriated investment, including foreign exchange impacts, in long-term other assets, which totalled approximately $105 million as at September 30, 2013 (December 31, 2012 - $104 million).

Risk Management: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation, Belize Electric Company Limited ("BECOL") and Griffith is the US dollar.

As at September 30, 2013, the Corporation's corporately issued US$1,044 million (December 31, 2012 – US$557 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at September 30, 2013, the Corporation had approximately US$549 million (December 31, 2012 – US$17 million) in foreign net investments remaining to be hedged. Both the Corporation's US dollar-denominated long-term debt and foreign net investments as at September 30, 2013 were significantly impacted by the CH Energy Group acquisition. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective from June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. The Corporation recognized in earnings a foreign exchange loss of $2 million for the three months ended and a foreign exchange gain of $3 million for the nine months ended September 30, 2013 ($3 million foreign exchange loss for the three and nine months ended September 30, 2012).

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel, electricity and natural gas prices through the use of derivative instruments. The Corporation and its subsidiaries do not hold or issue derivative instruments for trading purposes. As at September 30, 2013, the Corporation's derivative contracts consisted of fuel option contracts, electricity swap contracts, natural gas swap and option contracts, and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities. Electricity swap contracts are held by Central Hudson. Gas swaps and options and gas purchase contract premiums are held by the FortisBC Energy companies and Central Hudson.

The following table summarizes the Corporation's derivative instruments.

Derivative Instruments (Unaudited)				**As at**	
				September 30, 2013	December 31, 2012
(Liability) Asset	**Maturity**	**Number of Contracts**	**Volume** [1]	**Carrying Value** [2] ***($ millions)***	Carrying Value [2] *($ millions)*
Fuel option contracts [3]	**2013**	**2**	**1**	**-**	(1)
Electricity swap contracts	**2017**	**5**	**2,850**	**1**	-
Natural gas commodity derivatives:					
Gas swaps and options	**2014**	**49**	**10**	**(23)**	(51)
Gas purchase contract premiums	**2015**	**75**	**83**	**-**	(8)

[1] The volume for fuel option contracts is reported in millions of imperial gallons; electricity swap contracts in GWh; and natural gas commodity derivatives in PJ.
[2] Carrying value is estimated fair value. The (liability) asset represents the gross derivatives balance.
[3] The carrying value of the fuel option contracts was less than $1 million as at September 30, 2013.

The fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and was calculated using published market prices for heating oil or similar commodities where appropriate. The fuel option contracts matured in October 2013. Approximately 30% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The electricity swap contracts and natural gas commodity derivatives are used by Central Hudson to minimize commodity price volatility for electricity and natural gas purchases for the Company's full-service customers by fixing the effective purchase price for the defined commodities. The fair values of the electricity swap contracts and natural gas commodity derivatives were calculated using forward pricing provided by independent third parties.

The natural gas commodity derivatives are used by the FortisBC Energy companies to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas commodity derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, mitigate gas price volatility on customer rates and reduce the risk of regional price discrepancies. As directed by the regulator in 2011, the FortisBC Energy companies have suspended their commodity hedging activities with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

The fair values of the fuel option contracts, electricity swap contracts, and natural gas commodity derivatives are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

The changes in the fair values of the fuel option contracts, electricity swap contracts and natural gas commodity derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. The fair values of the derivative instruments were recorded in accounts payable and other current liabilities as at September 30, 2013 and December 31, 2012.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $66 million as at September 30, 2013 (December 31, 2012 - $67 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

Year-to-date 2013, the business risks of the Corporation were generally consistent with those disclosed in the Corporation's 2012 Annual MD&A, including certain risks, as disclosed below, and an update to those risks, where applicable.

Regulatory Risk: The allowed ROE and capital structure at Newfoundland Power have been set for 2013 through 2015 and remain unchanged from 2012. At FEI, the allowed ROE and capital structure have been set for 2013, resulting in a decrease of 75 basis points in the allowed ROE and a reduction in the common equity component of capital structure to 38.5% from 40% as compared to 2012.

Final allowed ROEs and capital structures for 2013 remain outstanding for FortisAlberta, FortisBC Electric, FEVI and FEWI. The results of cost of capital proceedings could materially impact the earnings of the above-noted utilities.

PBR commenced at FortisAlberta for a five-year term, beginning January 1, 2013. In March 2013 interim distribution electricity rates under PBR were approved by the AUC, in addition to the recovery, on an interim basis, of 60% of the revenue requirement associated with 2013 capital tracker expenditures applied for by FortisAlberta. While the AUC's 2012 PBR decision provides for a capital tracker mechanism to address recovery of certain capital expenditures outside of the PBR formula, the mechanism has yet to be tested to confirm its applicability to FortisAlberta's capital program. Final decisions on FortisAlberta's rates are expected in the fourth quarter of 2013.

For further information, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Acquisition of CH Energy Group: As a result of the closing of the CH Energy Group acquisition on June 27, 2013, the risks associated with the completion of the transaction are no longer applicable.

Expropriation of Shares in Belize Electricity: A decision is pending from the Belize Court of Appeal regarding the Corporation's appeal of the Belize Supreme Court's dismissal of the Corporation's claim filed in October 2011 challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity.

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a reasonable possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. The book value was $105 million, including foreign exchange impacts, as at September 30, 2013 (December 31, 2012 - $104 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis, for example: (i) the ordering of the return of the shares to Fortis and/or award of damages; or (ii) the ordering of compensation to be paid to Fortis for the unconstitutional expropriation of the shares. Based on presently available information, the $105 million long-term other asset is not deemed impaired as at September 30, 2013. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/United Kingdom Bilateral Investment Treaty.

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generating subsidiary in Belize. As at October 31, 2013, Belize Electricity owed BECOL US$2 million for overdue energy purchases, representing approximately 10% of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Capital Resources and Liquidity Risk - Credit Ratings: The Corporation's credit ratings were affirmed by S&P and DBRS in February 2013. Year-to-date 2013, the following changes were made to the credit ratings of the Corporation's utilities: (i) S&P updated Maritime Electric's debt credit rating from 'A- stable' to 'A stable' in February 2013; (ii) Moody's Investors Service ("Moody's"), in June 2013, affirmed the long-term credit ratings of FHI, FEI, FEVI and FortisBC Electric, and changed the rating outlooks to negative from stable; and (iii) Fitch Ratings and Moody's, in July 2013, affirmed Central Hudson's debt credit ratings at 'A stable' and 'A3 stable', respectively, and S&P also affirmed the Company's debt credit rating at 'A' and removed it from 'credit watch with negative implications'.

Defined Benefit Pension and OPEB Plan Assets: As at September 30, 2013, the fair value of the Corporation's consolidated defined benefit pension and OPEB plan assets was $1,563 million, up $695 million or 80%, from $868 million as at December 31, 2012. Of the increase from December 31, 2012, approximately $652 million, or 75%, was due to the acquisition of CH Energy Group.

Labour Relations: The collective agreement between the FortisBC Energy companies and the Canadian Office and Professional Employees Union ("COPE"), Local 378, expired on March 31, 2012. COPE represents employees in specified occupations in the areas of administration and operations support. A new three-year collective agreement, expiring on March 31, 2015, was reached in March 2013.

The collective agreement between FortisBC Electric and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on January 31, 2013. IBEW, Local 213, represents employees in specified occupations in the areas of generation and T&D. The parties have been negotiating since January 2013. The IBEW, Local 213 served the Company 72 hours' strike notice on March 13, 2013 and commenced partial job action on May 16, 2013. FortisBC Electric is operating under the most recent essential services order issued by the Labour Relations Board of British Columbia in September 2013. The essential services order outlines these services that are necessary to prevent immediate and serious danger to the health, safety or welfare of the citizens of British Columbia. FortisBC Electric activated the essential services order to provide certainty and stability in the delivery of electricity service. The Company is committed to reaching a fair and reasonable agreement that balances the needs of its employees and customers. Approximately 200 of FortisBC Electric's employees are members of the IBEW, Local 213.

Power Supply Contract: FortisBC Electric has a power supply sale agreement with BC Hydro for the sale of electricity generated from its non-regulated Walden Power Partnership hydroelectric generating facility, which has a net book value of approximately $10 million as at September 30, 2013. The agreement is set to expire in the fourth quarter of 2013. Accordingly, the Company is exposed to the risk that it will not be able to sell the power from this facility beyond 2013 on similar terms.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting pronouncements that are applicable to, and were adopted by, Fortis, effective January 1, 2013, are described as follows.

Disclosures About Offsetting Assets and Liabilities
The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet – Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") No. 2011-11 and ASU No. 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The above-noted amendments were applied retrospectively and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2013.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income
The Corporation adopted the amendments to ASC Topic 220, *Other Comprehensive Income - Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("AOCI")* as outlined in ASU No. 2013-02. The amendments improve the reporting of reclassifications out of AOCI and require entities to report, in one place, information about reclassifications out of AOCI and to present details of the reclassifications in the disclosure for changes in AOCI balances. The amendments were applied by the Corporation prospectively commencing on January 1, 2013 and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2013.

FUTURE ACCOUNTING PRONOUNCEMENTS

Obligations Resulting from Joint and Several Liability Arrangements
In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*. The objective of this update is to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Parent's Accounting for the Cumulative Translation Adjustment
In March 2013, FASB issued ASU No. 2013-5, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*. This update applies to the release of the cumulative translation adjustment into net earnings when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets within a foreign entity. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Presentation of an Unrecognized Tax Benefit
In July 2013, FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists.* This amendment provides guidance on the presentation of unrecognized tax benefits when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist and is intended to better reflect the manner in which an entity would settle any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's interim unaudited consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates year-to-date 2013 from those disclosed in the 2012 Annual MD&A.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval.

FHI
During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. A settlement was reached with CRA in the second quarter of 2013 resulting in the release of income tax provisions of approximately $5 million.

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

FortisBC Electric
The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake in 2003, prior to the acquisition of FortisBC Electric by Fortis, and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which includes FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the utility has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

Central Hudson

Danskammer Point Steam Electric Generating Station

In 1999, the New York State Attorney General alleged that Central Hudson may have constructed, and continued to operate, major modifications to the Danskammer Point Steam Electric Generating Station ("Danskammer Plant") without obtaining certain requisite pre-construction permits. In March 2000, the Environmental Protection Agency assumed responsibility for the investigation. Central Hudson believes any permits required for these projects were obtained in a timely manner. The Company sold the Danskammer Plant to Dynegy Inc. in January 2001. While Central Hudson could have retained liability after the sale, depending on the type of remedy, the Company believes that the statutes of limitation relating to any alleged violation of air emissions rules have lapsed.

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800's with all sites ceasing operations by the 1950's. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement, or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at September 30, 2013, an obligation of US$8 million was recognized in respect of MGPs remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$152 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, the differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Eltings Corners

Central Hudson owns and operates a maintenance and warehouse facility. In the course of Central Hudson's hazardous waste permit renewal process for this facility, sediment contamination was discovered within the wetland area across the street from the main property. In cooperation with the DEC, Central Hudson continues to investigate the nature and extent of the contamination. The extent of the contamination, as well as the timing and costs for any future remediation efforts, cannot be reasonably estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

Asbestos Litigation

Prior to the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,341 asbestos cases have been raised, 1,169 remained pending as at September 30, 2013. Of the cases no longer pending against Central Hudson, 2,017 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 155 cases. The Company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2011 through September 30, 2013. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results (Unaudited) Quarter Ended	**Revenue** *($ millions)*	**Net Earnings Attributable to Common Equity Shareholders** *($ millions)*	**Earnings per Common Share** Basic *($)*	Diluted *($)*
September 30, 2013	971	48	0.23	0.23
June 30, 2013	790	54	0.28	0.28
March 31, 2013	1,113	151	0.79	0.76
December 31, 2012	999	87	0.46	0.45
September 30, 2012	714	45	0.24	0.24
June 30, 2012	792	62	0.33	0.33
March 31, 2012	1,149	121	0.64	0.62
December 31, 2011	1,034	82	0.44	0.43

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

September 2013/September 2012: Net earnings attributable to common equity shareholders were $48 million, or $0.23 per common share, for the third quarter of 2013 compared to earnings of $45 million, or $0.24 per common share, for the third quarter of 2012. A discussion of the quarter over quarter variance in financial results is provided in the "Financial Highlights" section of this MD&A.

June 2013/June 2012: Net earnings attributable to common equity shareholders were $54 million, or $0.28 per common share, for the second quarter of 2013 compared to earnings of $62 million, or $0.33 per common share, for the second quarter of 2012. Earnings for the second quarter of 2013 were reduced by $32 million due to acquisition-related expenses and customer and community benefits offered to obtain regulatory approval of the acquisition of CH Energy Group, compared to $3 million of acquisition-related expenses in the second quarter of 2012. Earnings for the second quarter of 2013 were favourably impacted by an income tax recovery of $25 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends. In the second quarter of 2012, earnings were reduced by income tax expenses of $3 million associated with Part VI.1 tax. Excluding the above-noted acquisition-related and Part VI.1 tax impacts, net earnings for the second quarter of 2013 were $61 million compared to $68 million for the second quarter of 2012. The decrease in earnings was mainly due to lower contribution from the FortisBC Energy companies, FortisAlberta and FortisBC Electric, and decreased non-regulated hydroelectric production in Belize due to lower rainfall, partially offset by lower Corporate expenses. Earnings at the FortisBC Energy companies and FortisBC Electric were reduced by $8 million and

$2 million, respectively, as a result of the regulatory decision related to the first phase of the GCOC Proceeding in British Columbia, which was received in the second quarter of 2013. At the FortisBC Energy companies, earnings contribution from growth in energy infrastructure investment was largely offset by lower gas transportation volumes and lower-than-expected customer additions. FortisAlberta's earnings decreased due to lower net transmission revenue and timing of the recognition of a regulatory decision in 2012 impacting depreciation, partially offset by the timing of operating expenses, growth in energy infrastructure investment and customer growth. At FortisBC Electric, lower-than-expected finance charges, growth in energy infrastructure investment and higher capitalized AFUDC favourably impacted earnings. Lower Corporate expenses were primarily due to the favourable impact of the release of income tax provisions in the second quarter of 2013, a higher foreign exchange gain and lower finance charges, partially offset by higher preference share dividends.

March 2013/March 2012: Net earnings attributable to common equity shareholders were $151 million, or $0.79 per common share, for the first quarter of 2013 compared to earnings of $121 million, or $0.64 per common share, for the first quarter of 2012. Earnings for the first quarter of 2013 included an extraordinary gain of approximately $22 million after tax upon the settlement of expropriation matters associated with the Exploits Partnership. The remainder of the increase in earnings was primarily due to higher contribution from FortisAlberta, the FortisBC Energy companies and FortisBC Electric, and lower Corporate expenses. Higher earnings at FortisAlberta were primarily due to lower depreciation and net transmission revenue of approximately $2 million recognized in the first quarter of 2013 associated with the finalization of 2012 net transmission volume variances. At the FortisBC Energy companies, improved performance was mainly due to rate base growth and increased gas transportation volumes, partially offset by lower-than-expected customer additions and higher effective income taxes. Increased earnings at FortisBC Electric due to rate base growth, timing of operating expenses, lower-than-expected finance charges and depreciation, and higher capitalized AFUDC were partially offset by higher effective income taxes. Corporate expenses for the first quarter of 2013 were reduced by $2 million related to foreign exchange, while Corporate expenses for the first quarter of 2012 were increased by $1.5 million related to foreign exchange. Acquisition-related expenses in the first quarter of 2013 were approximately $0.5 million after tax compared to $4 million after tax in the first quarter of 2012. Excluding foreign exchange impacts and acquisition-related expenses noted above, Corporate expenses increased quarter over quarter mainly due to higher preference share dividends, partially offset by lower finance charges. The increase in earnings was partially offset by decreased non-regulated hydroelectric production in Belize due to lower rainfall and lower earnings at Maritime Electric and Fortis Properties.

December 2012/December 2011: Net earnings attributable to common equity shareholders were $87 million, or $0.46 per common share, for the fourth quarter of 2012 compared to earnings of $82 million, or $0.44 per common share, for the fourth quarter of 2011. The increase in earnings was primarily due to higher contribution from FortisAlberta, Other Canadian Regulated Electric Utilities and FortisBC Electric, partially offset by decreased non-regulated hydroelectric production in Belize associated with lower rainfall, increased Corporate expenses and decreased earnings at the FortisBC Energy companies. Higher earnings at FortisAlberta were driven by rate base growth, net transmission revenue of $2 million recognized in the fourth quarter of 2012 and the rate revenue reduction accrual during the fourth quarter of 2011, reflecting the cumulative impact from January 1, 2011 of the decrease in the allowed ROE for 2011. At Other Canadian Regulated Electric Utilities, improved performance was mainly due to lower effective income taxes at Maritime Electric and the accrual of the cumulative return earned on FortisOntario's capital investment in smart meters. Increased earnings at FortisBC Electric were driven by rate base growth, lower-than-expected finance charges in 2012 and higher pole-attachment revenue, partially offset by the expiry of the PBR mechanism on December 31, 2011. The increase in Corporate expenses was largely due to a $3 million non-recurring provision recognized in the fourth quarter of 2012 and lower effective income tax recoveries, partially offset by a foreign exchange gain of $1 million recognized in the fourth quarter of 2012, compared to a foreign exchange loss of $1 million recognized in the fourth quarter of 2011, and lower finance charges. At the FortisBC Energy companies, the decrease in earnings was mainly due to the timing of certain operating and maintenance expenses during 2012, lower capitalized AFUDC and lower-than-expected customer additions in 2012, partially offset by rate base growth, higher gas transportation volumes and lower effective income taxes.

OUTLOOK

Over the five years 2013 through 2017, the Corporation's consolidated capital expenditure program is expected to total approximately $6 billion and will support continuing growth in earnings and dividends. Capital investment over that period is expected to allow utility rate base and hydroelectric generation investment to increase at a combined compound annual growth rate of approximately 6%.

With the closing of the acquisition of CH Energy Group in June 2013, the Corporation's regulated midyear rate base has increased to more than $10 billion. The acquisition is expected to be accretive to earnings per common share of Fortis beginning in 2015.

Fortis remains disciplined and patient in its pursuit of additional electric and gas utility acquisitions in the United States and Canada that will add value for its shareholders. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

SUBSEQUENT EVENT

In October 2013 the Corporation issued 10-year US$285 million unsecured notes at 3.84% and 30-year US$40 million unsecured notes at 5.08%. Proceeds from the offering were used to repay a portion of the Corporation's US dollar-denominated credit facility borrowings incurred to initially finance a portion of the CH Energy Group acquisition and for general corporate purposes.

OUTSTANDING SHARE DATA

As at October 31, 2013, the Corporation had issued and outstanding approximately 212.4 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 10.0 million First Preference Shares, Series H; 8.0 million First Preference Shares, Series J; and 10.0 million First Preference Shares, Series K. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether or not such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options and First Preference Shares, Series E were converted as at October 31, 2013 is as follows.

Conversion of Securities into Common Shares (Unaudited) **As at October 31, 2013** **Security**	**Number of Common Shares** *(millions)*
Stock Options	**5.1**
First Preference Shares, Series E	**6.5**
Total	**11.6**

Additional information, including the Fortis 2012 Annual Information Form, Management Information Circular and Annual Report, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

FORTIS INC.

Interim Consolidated Financial Statements
For the three and nine months ended September 30, 2013 and 2012
(Unaudited)

Prepared in accordance with accounting principles generally accepted in the United States

Fortis Inc.
Consolidated Balance Sheets (Unaudited)
As at
(in millions of Canadian dollars)

	September 30, 2013	December 31, 2012
		(Note 25)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 155**	$ 154
Accounts receivable	**523**	587
Prepaid expenses	**53**	18
Inventories	**172**	133
Regulatory assets (Note 4)	**146**	185
Deferred income taxes	**34**	16
	1,083	1,093
Other assets	**233**	200
Regulatory assets (Note 4)	**1,825**	1,515
Deferred income taxes	**4**	-
Utility capital assets	**11,350**	9,623
Non-utility capital assets	**655**	626
Intangible assets	**356**	325
Goodwill (Note 15)	**2,064**	1,568
	$ 17,570	$ 14,950
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 20)	**$ 111**	$ 136
Accounts payable and other current liabilities	**847**	966
Regulatory liabilities (Note 4)	**108**	72
Current installments of long-term debt	**369**	159
Current installments of capital lease and finance obligations	**7**	7
Deferred income taxes	**9**	10
	1,451	1,350
Other liabilities	**808**	638
Regulatory liabilities (Note 4)	**804**	681
Deferred income taxes	**1,064**	702
Long-term debt	**6,750**	5,741
Capital lease and finance obligations	**421**	428
	11,298	9,540
Shareholders' equity		
Common shares [(1)] (Note 5)	**3,760**	3,121
Preference shares (Note 6)	**1,229**	1,108
Additional paid-in capital	**16**	15
Accumulated other comprehensive loss	**(101)**	(96)
Retained earnings	**1,013**	952
	5,917	5,100
Non-controlling interests (Note 7)	**355**	310
	6,272	5,410
	$ 17,570	$ 14,950

[(1)] *No par value. Unlimited authorized shares; 212.4 million and 191.6 million issued and outstanding as at September 30, 2013 and December 31, 2012, respectively*

Commitments and Contingent Liabilities (Notes 21 and 23, respectively)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Earnings (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars, except per share amounts)

	Quarter Ended		Nine Months Ended	
	2013	2012	**2013**	2012
Revenue	**$ 971**	$ 714	**$ 2,874**	$ 2,655
Expenses				
Energy supply costs	**356**	235	**1,143**	1,092
Operating	**299**	203	**726**	621
Depreciation and amortization	**141**	118	**400**	351
	796	556	**2,269**	2,064
Operating income	**175**	158	**605**	591
Other income (expenses), net (Note 10)	**2**	1	**(36)**	(2)
Finance charges (Note 11)	**103**	93	**284**	276
Earnings before income taxes and extraordinary item	**74**	66	**285**	313
Income tax expense (Note 12)	**7**	7	**3**	44
Earnings before extraordinary item	**67**	59	**282**	269
Extraordinary gain, net of tax (Note 13)	**-**	-	**22**	-
Net earnings	**$ 67**	$ 59	**$ 304**	$ 269
Net earnings attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**16**	11	**44**	34
Common equity shareholders	**48**	45	**253**	228
	$ 67	$ 59	**$ 304**	$ 269
Earnings per common share before extraordinary item (Note 14)				
Basic	**$ 0.23**	$ 0.24	**$ 1.16**	$ 1.20
Diluted	**$ 0.23**	$ 0.24	**$ 1.16**	$ 1.19
Earnings per common share (Note 14)				
Basic	**$ 0.23**	$ 0.24	**$ 1.27**	$ 1.20
Diluted	**$ 0.23**	$ 0.24	**$ 1.27**	$ 1.19

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Comprehensive Income (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Nine Months Ended	
	2013	2012	**2013**	2012
Net earnings	**$ 67**	$ 59	**$ 304**	$ 269
Other comprehensive loss				
Unrealized foreign currency translation losses, net of hedging activities and tax	**(15)**	(3)	**(7)**	(3)
Unrealized employee future benefits gains, net of tax	**-**	-	**2**	1
	(15)	(3)	**(5)**	(2)
Comprehensive income	**$ 52**	$ 56	**$ 299**	$ 267
Comprehensive income attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**16**	11	**44**	34
Common equity shareholders	**33**	42	**248**	226
	$ 52	$ 56	**$ 299**	$ 267

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Cash Flows (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Nine Months Ended	
	2013	2012	**2013**	2012
Operating activities				
Net earnings	**$ 67**	$ 59	**$ 304**	$ 269
Adjustments to reconcile net earnings to net cash provided by operating activities:				
Depreciation - capital assets	**123**	105	**351**	316
Amortization - intangible assets	**13**	12	**36**	33
Amortization - other	**5**	1	**13**	2
Deferred income tax expense (recovery)	**4**	-	**(18)**	8
Accrued employee future benefits	**12**	3	**14**	(4)
Equity component of allowance for funds used during construction (Note 10)	**(1)**	(1)	**(5)**	(4)
Other	**9**	1	**(14)**	(10)
Change in long-term regulatory assets and liabilities	**(45)**	(16)	**(54)**	(25)
Change in non-cash operating working capital (Note 17)	**(85)**	57	**53**	219
	102	221	**680**	804
Investing activities				
Change in other assets and other liabilities	**(3)**	(2)	**(16)**	2
Capital expenditures - utility capital assets	**(243)**	(264)	**(750)**	(737)
Capital expenditures - non-utility capital assets	**(11)**	(9)	**(35)**	(24)
Capital expenditures - intangible assets	**(8)**	(10)	**(24)**	(33)
Contributions in aid of construction	**16**	15	**46**	45
Business acquisitions, net of cash acquired (Note 15)	**-**	(7)	**(1,055)**	(14)
	(249)	(277)	**(1,834)**	(761)
Financing activities				
Change in short-term borrowings	**23**	17	**(55)**	(61)
Proceeds from long-term debt, net of issue costs	**150**	-	**201**	-
Repayments of long-term debt and capital lease and finance obligations	**(5)**	-	**(70)**	(57)
Net borrowings under committed credit facilities	**(187)**	(9)	**511**	221
Advances from non-controlling interests	**1**	14	**44**	83
Subscription Receipts issue costs (Note 5)	**-**	(1)	**-**	(13)
Issue of common shares, net of costs and dividends reinvested (Note 5)	**3**	6	**592**	12
Issue of preference shares, net of costs (Note 6)	**242**	-	**242**	-
Redemption of preference shares (Note 6)	**(125)**	-	**(125)**	-
Dividends				
Common shares, net of dividends reinvested	**(49)**	(42)	**(134)**	(128)
Preference shares	**(16)**	(11)	**(44)**	(34)
Subsidiary dividends paid to non-controlling interests	**(2)**	(2)	**(7)**	(6)
	35	(28)	**1,155**	17
Change in cash and cash equivalents	**(112)**	(84)	**1**	60
Cash and cash equivalents, beginning of period	**267**	231	**154**	87
Cash and cash equivalents, end of period	**$ 155**	$ 147	**$ 155**	$ 147

Supplementary Information to Consolidated Statements of Cash Flows (Note 17)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Changes in Equity (Unaudited)

For the periods ended September 30

(in millions of Canadian dollars)

	Common Shares *(Note 5)*	Preference Shares *(Note 6)*	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Non-Controlling Interests	Total Equity
As at January 1, 2013	**$ 3,121**	**$ 1,108**	**$ 15**	**$ (96)**	**$ 952**	**$ 310**	**$ 5,410**
Net earnings	**-**	**-**	**-**	**-**	**297**	**7**	**304**
Other comprehensive loss	**-**	**-**	**-**	**(5)**	**-**	**-**	**(5)**
Preference share issue	**-**	**244**	**-**	**-**	**-**	**-**	**244**
Preference share redemption	**-**	**(123)**	**-**	**-**	**-**	**-**	**(123)**
Common share issues	**639**	**-**	**(1)**	**-**	**-**	**-**	**638**
Stock-based compensation	**-**	**-**	**2**	**-**	**-**	**-**	**2**
Advances from non-controlling interests	**-**	**-**	**-**	**-**	**-**	**44**	**44**
Foreign currency translation impacts	**-**	**-**	**-**	**-**	**-**	**1**	**1**
Subsidiary dividends paid to non-controlling interests	**-**	**-**	**-**	**-**	**-**	**(7)**	**(7)**
Dividends declared on common shares ($0.93 per share)	**-**	**-**	**-**	**-**	**(192)**	**-**	**(192)**
Dividends declared on preference shares	**-**	**-**	**-**	**-**	**(44)**	**-**	**(44)**
As at September 30, 2013	**$ 3,760**	**$ 1,229**	**$ 16**	**$ (101)**	**$ 1,013**	**$ 355**	**$ 6,272**
As at January 1, 2012	$ 3,036	$ 912	$ 14	$ (95)	$ 868	$ 208	$ 4,943
Net earnings	-	-	-	-	262	7	269
Other comprehensive loss	-	-	-	(2)	-	-	(2)
Common share issues	56	-	(1)	-	-	-	55
Stock-based compensation	-	-	2	-	-	-	2
Advances from non-controlling interests	-	-	-	-	-	83	83
Foreign currency translation impacts	-	-	-	-	-	(4)	(4)
Subsidiary dividends paid to non-controlling interests	-	-	-	-	-	(6)	(6)
Dividends declared on common shares ($0.90 per share)	-	-	-	-	(173)	-	(173)
Dividends declared on preference shares	-	-	-	-	(34)	-	(34)
As at September 30, 2012	$ 3,092	$ 912	$ 15	$ (97)	$ 923	$ 288	$ 5,133

See accompanying Notes to Interim Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

NATURE OF OPERATIONS

Fortis Inc. ("Fortis" or the "Corporation") is principally an international gas and electric distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets and non-utility assets, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates autonomously, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following outlines each of the Corporation's reportable segments and is consistent with the basis of segmentation as disclosed in the Corporation's 2012 annual audited consolidated financial statements, with the exception of the acquisition of CH Energy Group, Inc. ("CH Energy Group") on June 27, 2013 (Note 15).

REGULATED UTILITIES

The Corporation's interests in regulated gas and electric utilities are as follows:

a. *Regulated Gas Utilities - Canadian:* The FortisBC Energy companies, comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc.

b. *Regulated Gas & Electric Utility - United States:* Central Hudson Gas & Electric Corporation ("Central Hudson"), acquired by Fortis as part of the acquisition of CH Energy Group (Note 15).

c. *Regulated Electric Utilities - Canadian:* Comprised of FortisAlberta, FortisBC Electric, Newfoundland Power, and Other Canadian Electric Utilities (Maritime Electric and FortisOntario). FortisOntario mainly includes Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company, Limited and Algoma Power Inc.

d. *Regulated Electric Utilities - Caribbean:* Comprised of Caribbean Utilities, in which Fortis holds an approximate 60% controlling interest; and two wholly owned utilities in the Turks and Caicos Islands, FortisTCI Limited ("FortisTCI") and Turks and Caicos Utilities Limited, acquired in August 2012, (collectively "Fortis Turks and Caicos"). In June 2013 Atlantic Equipment & Power (Turks and Caicos) Ltd. was amalgamated with FortisTCI.

NON-REGULATED - FORTIS GENERATION

Fortis Generation includes the financial results of non-regulated generation assets in Belize, Ontario, British Columbia and Upstate New York. In March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters, including release from all debt obligations, pertaining to the December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by the Exploits River Hydro Partnership ("Exploits Partnership") in which Fortis held an indirect 51% interest (Note 13).

NON-REGULATED - NON-UTILITY

a. Fortis Properties: Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada.

1. DESCRIPTION OF THE BUSINESS (cont'd)

NON-REGULATED - NON-UTILITY (cont'd)

b. *Griffith:* Comprised primarily of Griffith Energy Services, Inc. ("Griffith"), acquired by Fortis as part of the acquisition of CH Energy Group (Note 15). Griffith mainly supplies petroleum products and related services to approximately 65,000 customers in the Mid-Atlantic Region of the United States.

CORPORATE AND OTHER

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes Fortis net corporate expenses and the net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities. Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP") and FortisBC Alternative Energy Services Inc. ("FAES"). CWLP is a non-regulated shared-services business in which FHI holds a 30% interest. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. CWLP's financial results are recorded using the equity method of accounting. FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") for interim financial statements. As a result, these interim consolidated financial statements do not include all of the information and disclosures required in the annual consolidated financial statements and should be read in conjunction with the Corporation's 2012 annual audited consolidated financial statements. In management's opinion, the interim consolidated financial statements include all adjustments that are of a recurring nature and necessary to present fairly the consolidated financial position of the Corporation.

Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. As a result of natural gas consumption patterns, most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Given the diversified group of companies, seasonality may vary.

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the three and nine months ended September 30, 2013.

An evaluation of subsequent events through to October 31, 2013, the date these interim consolidated financial statements were approved by the Audit Committee of the Board of Directors, was completed to determine whether circumstances warranted recognition and disclosure of events or transactions in the interim consolidated financial statements as at September 30, 2013 (Note 24).

All amounts are presented in Canadian dollars unless otherwise stated.

These interim consolidated financial statements are comprised of the accounts of Fortis and its wholly owned subsidiaries and controlling ownership interests, including the financial statements of CH Energy Group commencing June 27, 2013, the date of acquisition. All significant intercompany balances and transactions have been eliminated on consolidation.

These interim consolidated financial statements have been prepared following the same accounting policies and methods as those used to prepare the Corporation's 2012 annual audited consolidated financial statements, except as described below.

Regulation

Central Hudson is regulated by the New York State Public Service Commission ("PSC") regarding such matters as rates, construction, operations, financing and accounting. Certain activities of the Company are subject to regulation by the U.S. Federal Energy Regulatory Commission under the *Federal Power Act* (United States). Central Hudson is also subject to regulation by the North American Electric Reliability Corporation.

Central Hudson operates under cost of service ("COS") regulation as administered by the PSC. The PSC uses a future test year to establish rates for the utility and, pursuant to this method, the determination of the approved rate of return on forecast rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined. Once rates are approved, they are not adjusted as a result of actual COS being different from that which was applied for, other than for certain prescribed costs that are eligible for deferral account treatment.

Central Hudson's allowed rate of return on common shareholders' equity ("ROE") is set at 10% on a deemed capital structure of 48% common equity. The Company began operating under a three-year rate order issued by the PSC effective July 1, 2010. As approved by the PSC in June 2013, the original three-year rate order has been extended for two years, through June 30, 2015, as a condition required to close the acquisition (Note 15). Effective July 1, 2013, Central Hudson is also subject to a modified earnings sharing mechanism, whereby the Company and customers equally share earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

Central Hudson's approved regulatory regime allows for full recovery of purchased electricity and natural gas costs. The Company's rates also include Revenue Decoupling Mechanisms ("RDMs"), which are intended to minimize the earnings impact resulting from reduced energy consumption as energy-efficiency programs are implemented. The RDMs allow the Company to recognize electric delivery revenue and gas revenue at the levels approved in rates for most of Central Hudson's customer base. Deferral account treatment is approved for certain other specified costs, including provisions for manufactured gas plant ("MGP") site remediation, pension and other post employment benefit ("OPEB") costs.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

New Accounting Policies

Disclosures About Offsetting Assets and Liabilities
Effective January 1, 2013, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet - Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") No. 2011-11 and ASU No. 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The above-noted amendments were applied retrospectively and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2013.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income
Effective January 1, 2013, the Corporation adopted the amendments to ASC Topic 220, *Other Comprehensive Income - Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("AOCI")* as outlined in ASU No. 2013-02. The amendments improve the reporting of reclassifications out of AOCI and require entities to report, in one place, information about reclassifications out of AOCI and to present details of the reclassifications in the disclosure for changes in AOCI balances. The amendments were applied by the Corporation prospectively commencing on January 1, 2013 and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2013.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Obligations Resulting from Joint and Several Liability Arrangements
In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*. The objective of this update is to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Parent's Accounting for the Cumulative Translation Adjustment
In March 2013, FASB issued ASU No. 2013-5, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity.* This update applies to the release of the cumulative translation adjustment into net earnings when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets within a foreign entity. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Presentation of an Unrecognized Tax Benefit
In July 2013, FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists.* This amendment provides guidance on the presentation of unrecognized tax benefits when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist and is intended to better reflect the manner in which an entity would settle any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist. This accounting update is effective for annual and interim periods beginning on or after December 15, 2013 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

4. REGULATORY ASSETS AND LIABILITIES

A summary of the Corporation's regulatory assets and liabilities is provided below. For a detailed description of the nature of the Corporation's regulatory assets and liabilities, refer to Note 7 to the Corporation's 2012 annual audited consolidated financial statements.

	As at	
($ millions)	**September 30, 2013**	December 31, 2012
Regulatory assets		
Deferred income taxes *(i)*	**822**	713
Employee future benefits *(i)*	**637**	498
Deferred lease costs - FortisBC Electric	**81**	77
Deferred energy management costs *(i)*	**61**	50
Rate stabilization accounts - electric utilities *(i)*	**56**	57
Deferred operating overhead costs	**40**	32
Deferred net losses on disposal of utility capital assets and intangible assets	**34**	27
Rate stabilization accounts - gas utilities *(i)*	**29**	48
Income taxes recoverable on OPEB plans	**23**	23
Customer Care Enhancement Project cost deferral	**22**	24
Alternative energy projects cost deferral	**15**	18
Whistler pipeline contribution deferral	**13**	14
MGP site remediation deferral *(i)*	**12**	-
Deferred development costs for capital projects	**10**	10
Natural gas transportation incentive deferral	**9**	4
Residual natural gas deferral *(i)*	**7**	-
Deferred costs - smart meters	**1**	9
Replacement energy deferral - Point Lepreau *(ii)*	**-**	47
Other regulatory assets *(i)*	**99**	49
Total regulatory assets	**1,971**	1,700
Less: current portion	**(146)**	(185)
Long-term regulatory assets	**1,825**	1,515

	As at	
($ millions)	**September 30, 2013**	December 31, 2012
Regulatory liabilities		
Non-asset retirement obligation removal cost provision *(iii)*	**556**	486
Rate stabilization accounts - gas utilities *(iii)*	**105**	117
Rate stabilization accounts - electric utilities *(iii)*	**41**	46
Alberta Electric System Operator charges deferral	**40**	44
Deferred income taxes *(iii)*	**31**	12
OPEB cost deferral *(iii)*	**27**	-
Customer and community benefits obligation *(iii)*	**22**	-
Meter reading and customer service variance deferral	**13**	6
Rate base impact of tax repair project *(iii)*	**10**	-
Deferred interest	**8**	9
Income tax variance deferral	**3**	7
Other regulatory liabilities *(iii)*	**56**	26
Total regulatory liabilities	**912**	753
Less: current portion	**(108)**	(72)
Long-term regulatory liabilities	**804**	681

4. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities

(i) The respective regulatory assets as at September 30, 2013 include amounts related to Central Hudson. MGP site remediation and residual natural gas deferrals are being amortized and collected from customers over a two- and four-year period, respectively, as approved by the regulator.

(ii) In March 2013 Maritime Electric received proceeds of approximately $47 million from the Government of Prince Edward Island upon its assumption of the utility's replacement energy deferral during the refurbishment of the New Brunswick Power Point Lepreau nuclear generating station ("Point Lepreau").

(iii) The respective regulatory liabilities as at September 30, 2013 include amounts related to Central Hudson. As approved by the regulator, the difference between Central Hudson's defined benefit pension and OPEB costs recognized under US GAAP and those which are expected to be refunded to, or recovered from, customers in future rates are subject to deferral account treatment. As a result, a regulatory liability has been recognized in relation to Central Hudson's OPEB plan.

As approved by the PSC, Fortis will provide Central Hudson's customers and community with approximately US$50 million in financial benefits that would not have been realized in the absence of the acquisition (Note 15). These incremental benefits include: (i) US$35 million to cover expenses that would normally be recovered in customer rates; (ii) guaranteed savings to customers of more than US$9 million over five years resulting from the elimination of costs CH Energy Group would otherwise incur as a public company; and (iii) the establishment of a US$5 million Community Benefit Fund to be used for low-income customer and economic development programs for communities and residents of the Mid-Hudson River Valley. As a result, $41 million (US$40 million) in expenses were recognized in the second quarter of 2013 associated with the write-off of a $20 million (US$20 million) regulatory asset related to deferred storm costs and the recognition of a regulatory liability for customer and community benefits of $21 million (US$20 million) (Notes 10 and 15).

The tax repair project regulatory liability represents accumulated tax refunds plus accrued carrying charges to be refunded to customers through future rates over a time period to be determined during Central Hudson's next rate hearing with the PSC.

5. COMMON SHARES

Common shares issued during the period were as follows:

	Quarter Ended September 30, 2013		**Year-to-Date September 30, 2013**	
	Number of Shares *(in thousands)*	**Amount *($ millions)***	**Number of Shares *(in thousands)***	**Amount *($ millions)***
Balance, beginning of period	**211,717**	**3,739**	**191,566**	**3,121**
Public offering - Conversion of Subscription Receipts	**-**	**-**	**18,500**	**567**
Dividend Reinvestment Plan	**591**	**17**	**1,637**	**52**
Consumer Share Purchase Plan	**10**	**-**	**27**	**1**
Employee Share Purchase Plan	**76**	**3**	**293**	**10**
Stock Option Plans	**24**	**1**	**395**	**9**
Balance, end of period	**212,418**	**3,760**	**212,418**	**3,760**

5. COMMON SHARES (cont'd)

In June 2012, to finance a portion of the acquisition of CH Energy Group, the Corporation sold 18.5 million Subscription Receipts at $32.50 each, for gross proceeds of approximately $601 million. On June 27, 2013, upon closing of the acquisition of CH Energy Group, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt Holder also received a cash payment of $1.22 per Subscription Receipt, which is an amount equal to the aggregate amount of dividends declared per common share of Fortis for which record dates have occurred since the issuance of the Subscription Receipts. The proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $567 million, net of after-tax expenses (Note 15).

6. PREFERENCE SHARES

In July 2013, the Corporation redeemed all of the issued and outstanding $125 million 5.45% First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $2 million of after-tax issuance costs associated with First Preference Shares, Series C were recognized in net earnings attributable to preference equity shareholders.

In July 2013, the Corporation issued 10 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K ("First Preference Shares, Series K") at a price of $25.00 per share for net after-tax proceeds of $244 million.

The First Preference Shares, Series K are entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors of the Corporation at a rate of 4.0%, in an amount equal to $1.00 per share per annum, for each year up to but excluding March 1, 2019. The dividends are payable in equal quarterly installments on the first day of each quarter. For each five-year period after that date, the holders of First Preference Shares, Series K are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.05%.

On each Series K Conversion Date, the holders of First Preference Shares, Series K, have the option to convert any or all of their First Preference Shares, Series K into an equal number of Cumulative Redeemable Floating Rate First Preference Shares, Series L ("First Preference Shares, Series L"). The holders of the Corporation's First Preference Shares, Series L will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 2.05%.

On or after specified dates, the Corporation has the option to redeem for cash all or any part of the outstanding First Preference Shares, Series K and First Preference Shares, Series L at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

First Preference Shares, Series K and First Preference Shares, Series L do not have fixed maturity dates and are not redeemable at the option of the holders.

7. NON-CONTROLLING INTERESTS

($ millions)	As at September 30, 2013	December 31, 2012
Waneta Expansion Limited Partnership ("Waneta Partnership")	**262**	220
Caribbean Utilities	**74**	71
Mount Hayes Limited Partnership	**12**	12
Preference shares of Newfoundland Power	**7**	7
	355	310

8. STOCK-BASED COMPENSATION PLANS

In January 2013, 8,497 Deferred Share Units ("DSUs") were granted to the Corporation's Board of Directors, representing the first quarter equity component of the Directors' annual compensation and, where opted, their first quarter component of annual retainers in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

In March 2013, 66,978 Performance Share Units ("PSUs") were paid out to the President and Chief Executive Officer ("CEO") of the Corporation at $33.59 per PSU, for a total of approximately $2 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2010 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

In March 2013 the Corporation granted 807,600 options to purchase common shares under its 2012 Stock Option Plan ("2012 Plan") at the five-day volume weighted average trading price immediately preceding the date of grant of $33.58. The options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2012 Plan. The fair value of each option granted was $3.91 per option.

The fair value was estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

Dividend yield (%)	3.78
Expected volatility (%)	21.4
Risk-free interest rate (%)	1.31
Weighted average expected life (years)	5.3

8. STOCK-BASED COMPENSATION PLANS (cont'd)

In March 2013 the Corporation's Board of Directors approved the 2013 PSU Plan, effective January 1, 2013. The 2013 PSU Plan represents a component of the long-term incentives awarded to senior management of the Corporation and its subsidiaries, including the President and CEO of Fortis. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors. In May 2013, 136,058 PSUs were granted to senior management of the Corporation and its subsidiaries.

In April 2013, 8,553 DSUs were granted to the Corporation's Board of Directors, representing the second quarter equity component of the Directors' annual compensation and, where opted, their second quarter component of annual retainers in lieu of cash.

In July 2013, 7,892 DSUs were granted to the Corporation's Board of Directors, representing the third quarter equity component of the Directors' annual compensation and, where opted, their third quarter component of annual retainers in lieu of cash.

For the three and nine months ended September 30, 2013, stock-based compensation expense of approximately $1 million and $5 million, respectively, was recognized ($2 million and $5 million for the three and nine months ended September 30, 2012, respectively).

9. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group registered retirement savings plans, for employees. The Corporation and certain subsidiaries also offer OPEB plans for qualifying employees. The net benefit cost of providing the defined benefit pension and OPEB plans is detailed in the following tables.

	Quarter Ended September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2013**	2012	**2013**	2012
Components of net benefit cost:				
Service costs	**10**	6	**3**	2
Interest costs	**18**	12	**4**	2
Expected return on plan assets	**(21)**	(12)	**-**	-
Amortization of actuarial losses	**13**	6	**3**	2
Amortization of past service credits/plan amendments	**-**	-	**(2)**	-
Regulatory adjustments	**(3)**	(2)	**(2)**	-
Net benefit cost	**17**	10	**6**	6

	Year-to-Date September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2013**	2012	**2013**	2012
Components of net benefit cost:				
Service costs	**26**	20	**7**	5
Interest costs	**41**	35	**10**	8
Expected return on plan assets	**(48)**	(37)	**-**	-
Amortization of actuarial losses	**27**	19	**6**	4
Amortization of past service credits/plan amendments	**-**	-	**(4)**	(2)
Amortization of transitional obligation	**-**	1	**-**	1
Regulatory adjustments	**(10)**	(8)	**(1)**	1
Net benefit cost	**36**	30	**18**	17

9. EMPLOYEE FUTURE BENEFITS (cont'd)

For the three and nine months ended September 30, 2013, the Corporation expensed $5 million and $12 million, respectively ($3 million and $10 million for the three and nine months ended September 30, 2012 respectively), related to defined contribution pension plans.

10. OTHER INCOME (EXPENSES), NET

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2013**	2012	**2013**	2012
Equity component of allowance for funds used during construction ("AFUDC")	**1**	1	**5**	4
Net foreign exchange (loss) gain (Notes 20 and 22)	**(2)**	(3)	**3**	(3)
Interest income	**3**	2	**5**	4
Acquisition-related expenses (Note 15)	**(1)**	-	**(9)**	(8)
Acquisition-related customer and community benefits (Notes 4 and 15)	**-**	-	**(41)**	-
Other	**1**	1	**1**	1
	2	1	**(36)**	(2)

11. FINANCE CHARGES

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2013**	2012	**2013**	2012
Interest:				
Long-term debt and capital lease and finance obligations	**106**	95	**294**	282
Short-term borrowings	**2**	3	**6**	6
Debt component of AFUDC	**(5)**	(5)	**(16)**	(12)
	103	93	**284**	276

12. INCOME TAXES

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory income taxes to consolidated effective income taxes.

	Quarter Ended September 30		Year-to-Date September 30	
($ millions, except as noted)	**2013**	2012	**2013**	2012
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	29.0%	**29.0%**	29.0%
Statutory income tax rate applied to earnings before income taxes and extraordinary item	**21**	19	**83**	91
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(5)**	(3)	**(13)**	(10)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**-**	(1)	**(8)**	(9)
Items capitalized for accounting purposes but expensed for income tax purposes	**(13)**	(11)	**(39)**	(39)
Difference between capital cost allowance and amounts claimed for accounting purposes	**6**	3	**4**	7
Non-deductible expenses	**1**	2	**3**	5
Impacts associated with Part VI.1 tax	**-**	(1)	**(23)**	2
Release of income tax reserves	**(2)**	-	**(7)**	(2)
Difference between employee future benefits paid and amounts expensed for accounting purposes	**-**	-	**1**	1
Other	**(1)**	(1)	**2**	(2)
Income tax expense	**7**	7	**3**	44
Effective income tax rate	**9.5%**	10.6%	**1.1%**	14.1%

In June 2013 the Government of Canada enacted changes associated with Part VI.1 tax on the Corporation's preference share dividends. In accordance with US GAAP, income taxes are required to be recognized based on enacted tax legislation. In the second quarter of 2013, the Corporation recognized an approximate $25 million income tax recovery due to the enactment of higher deductions associated with Part VI.1 tax.

In June 2013 a settlement was reached with Canada Revenue Agency ("CRA") resulting in the release of income tax provisions of approximately $5 million (Note 23).

As at September 30, 2013, the Corporation had non-capital and capital loss carryforwards of approximately $108 million (December 31, 2012 - $73 million), of which $17 million (December 31, 2012 - $13 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2013 and 2033.

13. EXTRAORDINARY GAIN, NET OF TAX

Effective March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters, including release from all debt obligations, pertaining to the December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by the Exploits Partnership, in which Fortis held an indirect 51% interest. As a result of the settlement an extraordinary gain of approximately $25 million ($22 million after tax) was recognized in the first quarter of 2013.

14. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. Diluted EPS is calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

	Earnings to Common Shareholders				Earnings Per Share		
Quarter Ended September 30, 2013	Before Extraordinary Gain (*$ millions*)	Extraordinary Gain (*$ millions*)	After Extraordinary Gain (*$ millions*)	Weighted Average Shares (*millions*)	Before Extraordinary Gain	Extraordinary Gain	After Extraordinary Gain
Basic EPS	**48**	**-**	**48**	**212.0**	**$ 0.23**	**$ -**	**$ 0.23**
Effect of potential dilutive securities:							
Stock Options	**-**	**-**	**-**	**0.7**			
Preference Shares	**3**	**-**	**3**	**6.5**			
	51	**-**	**51**	**219.2**			
Deduct anti-dilutive impacts:							
Preference Shares	**(3)**	**-**	**(3)**	**(6.5)**			
Diluted EPS	**48**	**-**	**48**	**212.7**	**$ 0.23**	**$ -**	**$ 0.23**
Quarter Ended September 30, 2012							
Basic EPS	45	-	45	190.2	$ 0.24	$ -	$ 0.24
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.9			
Preference Shares	4	-	4	10.3			
	49	-	49	201.4			
Deduct anti-dilutive impacts:							
Preference Shares	(4)	-	(4)	(10.3)			
Diluted EPS	45	-	45	191.1	$ 0.24	$ -	$ 0.24

	Earnings to Common Shareholders				Earnings Per Share		
Year-to-Date September 30, 2013	Before Extraordinary Gain (*$ millions*)	Extraordinary Gain (*$ millions*)	After Extraordinary Gain (*$ millions*)	Weighted Average Shares (*millions*)	Before Extraordinary Gain	Extraordinary Gain	After Extraordinary Gain
Basic EPS	**231**	**22**	**253**	**199.1**	**$ 1.16**	**$ 0.11**	**$ 1.27**
Effect of potential dilutive securities:							
Stock Options	**-**	**-**	**-**	**0.7**			
Preference Shares	**11**	**-**	**11**	**8.8**			
	242	**22**	**264**	**208.6**			
Deduct anti-dilutive impacts:							
Preference Shares	**(11)**	**-**	**(11)**	**(8.8)**			
Diluted EPS	**231**	**22**	**253**	**199.8**	**$ 1.16**	**$ 0.11**	**$ 1.27**
Year-to-Date September 30, 2012							
Basic EPS	228	-	228	189.6	$ 1.20	$ -	$ 1.20
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.9			
Preference Shares	12	-	12	10.3			
	240	-	240	200.8			
Deduct anti-dilutive impacts:							
Preference Shares	(5)	-	(5)	(3.9)			
Diluted EPS	235	-	235	196.9	$ 1.19	$ -	$ 1.19

15. BUSINESS ACQUISITIONS

CH ENERGY GROUP

On June 27, 2013 Fortis acquired all of the outstanding common shares of CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. The net cash purchase price of approximately $1,019 million (US$972 million) was financed through proceeds from the issuance of 18.5 million common shares of Fortis, pursuant to the conversion of Subscription Receipts on the closing of the acquisition, for proceeds of approximately $567 million, net of after-tax expenses (Note 5), with the balance being initially funded through drawings under the Corporation's $1 billion committed credit facility.

CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated transmission and distribution utility serving approximately 300,000 electric and 76,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson accounts for approximately 93% of the total assets of CH Energy Group and is subject to regulation by the PSC under a traditional COS model (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. Therefore, in determining the fair value of assets and liabilities of Central Hudson at the date of acquisition, fair value approximates book value. No fair value adjustments were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

Non-regulated net assets acquired relate mainly to Griffith, which is primarily a fuel delivery business. Fair value approximates book value, with the exception of intangible assets associated with Griffith's customer relationships.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at June 27, 2013 based on their fair values, using an exchange rate of US$1.00=CDN$1.0484. The amount of the purchase price allocated to goodwill is entirely associated with the regulated gas and electric operations of Central Hudson.

($ millions)	**Total**
Purchase consideration	**1,019**
Fair value assigned to net assets:	
Current assets	**215**
Long-term regulatory assets	**235**
Utility capital assets	**1,283**
Non-utility capital assets	**11**
Intangible assets	**45**
Other long-term assets	**33**
Current liabilities	**(133)**
Assumed short-term borrowings	**(39)**
Assumed long-term debt (including current portion)	**(543)**
Long-term regulatory liabilities	**(123)**
Other long-term liabilities	**(468)**
	516
Cash and cash equivalents	**19**
Fair value of net assets acquired	**535**
Goodwill	**484**

15. BUSINESS ACQUISITIONS (cont'd)

CH ENERGY GROUP (cont'd)

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on June 27, 2013.

Acquisition-related expenses totalled approximately $9 million ($6 million after tax) for the nine months ended September 30, 2013 and have been recognized in other income (expenses), net on the consolidated statement of earnings (Note 10). In addition, approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, in customer and community benefits offered to obtain regulatory approval of the acquisition were expensed in the second quarter of 2013, as approved by the PSC, and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 4 and 10).

Supplemental Pro Forma Data
The unaudited pro forma financial information below gives effect to the acquisition of CH Energy Group as if the transaction had occurred at the beginning of 2012. This pro forma data is presented for information purposes only, and does not necessarily represent the results that would have occurred had the acquisition taken place at the beginning of 2012, nor is it necessarily indicative of the results that may be expected in future periods.

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2013**	2012	**2013**	2012
Pro forma revenue	**971**	931	**3,391**	3,346
Pro forma net earnings (1)	**67**	65	**357**	300

(1) Pro forma net earnings exclude all acquisition-related expenses incurred by CH Energy Group and the Corporation, net of tax (Note 10). A pro forma adjustment has been made to net earnings for the respective periods presented to reflect the Corporation's after-tax financing costs associated with the acquisition.

CITY OF KELOWNA'S ELECTRICAL UTILITY ASSETS

In March 2013 FortisBC Electric acquired the electrical utility assets of the City of Kelowna (the "City") for approximately $55 million, which now allows FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electrical utility assets under contract since 2000.

The acquisition was approved by the British Columbia Utilities Commission ("BCUC") in March 2013 and allowed for approximately $38 million of the purchase price to be included in FortisBC Electric's rate base. Based on this regulatory decision, the book value of the assets acquired has been assigned as fair value in the purchase price allocation. FortisBC Electric is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change in ownership. Therefore, in determining the fair value of assets at the date of acquisition, fair value approximates book value. No fair value adjustments were recorded for the assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

15. BUSINESS ACQUISITIONS (cont'd)

CITY OF KELOWNA'S ELECTRICAL UTILITY ASSETS (cont'd)

The following table summarizes the allocation of the purchase price to the assets acquired as at the date of acquisition based on their fair values.

($ millions)	**Total**
Purchase consideration	**55**
Fair value assigned to assets:	
Utility capital assets	**38**
Long-term deferred income tax asset	**3**
Fair value of assets acquired	**41**
Goodwill	**14**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing in March 2013.

16. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED UTILITIES								NON-REGULATED				
	Gas	Gas & Electric	Electric										
Quarter Ended September 30, 2013 *($ millions)*	**FortisBC Energy Canadian**	**Central Hudson US**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	**194**	**170**	119	74	105	97	**395**	**77**	**12**	**124**	**6**	**(7)**	**971**
Energy supply costs	**64**	**62**	-	19	54	65	**138**	**47**	**-**	**45**	**-**	**-**	**356**
Operating expenses	**70**	**72**	39	19	19	11	**88**	**10**	**2**	**56**	**2**	**(1)**	**299**
Depreciation and amortization	**44**	**10**	37	12	13	7	**69**	**9**	**2**	**7**	**-**	**-**	**141**
Operating income	**16**	**26**	43	24	19	14	**100**	**11**	**8**	**16**	**4**	**(6)**	**175**
Other income (expenses), net	**1**	**1**	-	-	1	-	**1**	**1**	**-**	**-**	**(1)**	**(1)**	**2**
Finance charges	**35**	**8**	18	10	9	5	**42**	**4**	**-**	**8**	**13**	**(7)**	**103**
Income tax (recovery) expense	**(5)**	**7**	-	3	3	2	**8**	**-**	**-**	**2**	**(5)**	**-**	**7**
Net (loss) earnings	**(13)**	**12**	25	11	8	7	**51**	**8**	**8**	**6**	**(5)**	**-**	**67**
Non-controlling interests	**1**	**-**	-	-	-	-	**-**	**2**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**16**	**-**	**16**
Net (loss) earnings attributable to common equity shareholders	**(14)**	**12**	25	11	8	7	**51**	**6**	**8**	**6**	**(21)**	**-**	**48**
Goodwill	**913**	**476**	227	235	-	67	**529**	**146**	**-**	**-**	**-**	**-**	**2,064**
Identifiable assets	**4,504**	**1,710**	2,973	1,775	1,375	698	**6,821**	**673**	**837**	**792**	**637**	**(468)**	**15,506**
Total assets	**5,417**	**2,186**	3,200	2,010	1,375	765	**7,350**	**819**	**837**	**792**	**637**	**(468)**	**17,570**
Gross capital expenditures	**50**	**28**	77	25	25	12	**139**	**11**	**22**	**12**	**-**	**-**	**262**

Quarter Ended September 30, 2012 *($ millions)*													
Revenue	**192**	**-**	117	71	100	91	**379**	**72**	**8**	**65**	**5**	**(7)**	**714**
Energy supply costs	**61**	**-**	-	16	54	59	**129**	**45**	**-**	**-**	**-**	**-**	**235**
Operating expenses	**64**	**-**	40	20	17	11	**88**	**7**	**2**	**42**	**2**	**(2)**	**203**
Depreciation and amortization	**40**	**-**	34	12	11	7	**64**	**8**	**1**	**5**	**-**	**-**	**118**
Operating income	**27**	**-**	43	23	18	14	**98**	**12**	**5**	**18**	**3**	**(5)**	**158**
Other income (expenses), net	**1**	**-**	-	1	1	-	**2**	**1**	**-**	**-**	**(3)**	**-**	**1**
Finance charges	**36**	**-**	17	9	9	4	**39**	**4**	**-**	**6**	**13**	**(5)**	**93**
Income tax (recovery) expense	**(2)**	**-**	-	2	1	3	**6**	**-**	**-**	**4**	**(1)**	**-**	**7**
Net (loss) earnings	**(6)**	**-**	26	13	9	7	**55**	**9**	**5**	**8**	**(12)**	**-**	**59**
Non-controlling interests	**-**	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Net (loss) earnings attributable to common equity shareholders	**(6)**	**-**	26	13	9	7	**55**	**6**	**5**	**8**	**(23)**	**-**	**45**
Goodwill	**913**	**-**	227	221	-	67	**515**	**138**	**-**	**-**	**-**	**-**	**1,566**
Identifiable assets	**4,472**	**-**	2,651	1,686	1,289	705	**6,331**	**735**	**686**	**623**	**498**	**(425)**	**12,920**
Total assets	**5,385**	**-**	2,878	1,907	1,289	772	**6,846**	**873**	**686**	**623**	**498**	**(425)**	**14,486**
Gross capital expenditures	**66**	**-**	104	19	22	13	**158**	**11**	**39**	**9**	**-**	**-**	**283**

16. SEGMENTED INFORMATION (cont'd)

	REGULATED UTILITIES								NON-REGULATED				
	Gas	Gas & Electric	Electric										
Year-to-Date September 30, 2013 *($ millions)*	**FortisBC Energy Canadian**	**Central Hudson US**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	**932**	**170**	354	230	434	280	**1,298**	**213**	**24**	**242**	**19**	**(24)**	**2,874**
Energy supply costs	**386**	**62**	-	58	279	183	**520**	**131**	**-**	**45**	**-**	**(1)**	**1,143**
Operating expenses	**207**	**72**	117	61	58	36	**272**	**26**	**7**	**139**	**8**	**(5)**	**726**
Depreciation and amortization	**136**	**10**	109	37	38	21	**205**	**26**	**4**	**18**	**1**	**-**	**400**
Operating income	**203**	**26**	128	74	59	40	**301**	**30**	**13**	**40**	**10**	**(18)**	**605**
Other income (expenses), net	**2**	**1**	2	1	2	-	**5**	**2**	**-**	**-**	**(45)**	**(1)**	**(36)**
Finance charges	**106**	**8**	53	29	27	15	**124**	**11**	**-**	**20**	**34**	**(19)**	**284**
Income tax expense (recovery)	**21**	**7**	1	9	(5)	3	**8**	**-**	**-**	**5**	**(38)**	**-**	**3**
Net earnings (loss) before extraordinary item	**78**	**12**	76	37	39	22	**174**	**21**	**13**	**15**	**(31)**	**-**	**282**
Extraordinary gain, net of tax	**-**	**-**	-	-	-	-	**-**	**-**	**22**	**-**	**-**	**-**	**22**
Net earnings (loss)	**78**	**12**	76	37	39	22	**174**	**21**	**35**	**15**	**(31)**	**-**	**304**
Non-controlling interests	**1**	**-**	-	-	-	-	**-**	**6**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**44**	**-**	**44**
Net earnings (loss) attributable to common equity shareholders	**77**	**12**	76	37	39	22	**174**	**15**	**35**	**15**	**(75)**	**-**	**253**
Goodwill	**913**	**476**	227	235	-	67	**529**	**146**	**-**	**-**	**-**	**-**	**2,064**
Identifiable assets	**4,504**	**1,710**	2,973	1,775	1,375	698	**6,821**	**673**	**837**	**792**	**637**	**(468)**	**15,506**
Total assets	**5,417**	**2,186**	3,200	2,010	1,375	765	**7,350**	**819**	**837**	**792**	**637**	**(468)**	**17,570**
Gross capital expenditures	**142**	**28**	306	58	63	40	**467**	**35**	**101**	**36**	**-**	**-**	**809**

Year-to-Date September 30, 2012 *($ millions)*													
Revenue	**1,004**	**-**	335	225	422	264	**1,246**	**202**	**26**	**181**	**18**	**(22)**	**2,655**
Energy supply costs	**472**	**-**	-	54	274	168	**496**	**124**	**1**	**-**	**-**	**(1)**	**1,092**
Operating expenses	**197**	**-**	116	62	54	35	**267**	**24**	**6**	**124**	**8**	**(5)**	**621**
Depreciation and amortization	**120**	**-**	99	36	33	20	**188**	**24**	**3**	**15**	**1**	**-**	**351**
Operating income	**215**	**-**	120	73	61	41	**295**	**30**	**16**	**42**	**9**	**(16)**	**591**
Other income (expenses), net	**2**	**-**	2	1	2	-	**5**	**2**	**1**	**-**	**(11)**	**(1)**	**(2)**
Finance charges	**107**	**-**	49	29	27	15	**120**	**11**	**1**	**18**	**36**	**(17)**	**276**
Income tax expense (recovery)	**20**	**-**	-	7	8	7	**22**	**-**	**1**	**7**	**(6)**	**-**	**44**
Net earnings (loss)	**90**	**-**	73	38	28	19	**158**	**21**	**15**	**17**	**(32)**	**-**	**269**
Non-controlling interests	**1**	**-**	-	-	-	-	**-**	**6**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**34**	**-**	**34**
Net earnings (loss) attributable to common equity shareholders	**89**	**-**	73	38	28	19	**158**	**15**	**15**	**17**	**(66)**	**-**	**228**
Goodwill	**913**	**-**	227	221	-	67	**515**	**138**	**-**	**-**	**-**	**-**	**1,566**
Identifiable assets	**4,472**	**-**	2,651	1,686	1,289	705	**6,331**	**735**	**686**	**623**	**498**	**(425)**	**12,920**
Total assets	**5,385**	**-**	2,878	1,907	1,289	772	**6,846**	**873**	**686**	**623**	**498**	**(425)**	**14,486**
Gross capital expenditures	**144**	**-**	304	52	58	35	**449**	**33**	**144**	**24**	**-**	**-**	**794**

16. SEGMENTED INFORMATION (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) electricity sales from Newfoundland Power to Non-Utility; and (ii) finance charges on related party borrowings. The significant related party inter-segment transactions for the three and nine months ended September 30, 2013 and 2012 were as follows:

Significant Inter-Segment Transactions	**Quarter Ended September 30**		**Year-to-Date September 30**	
($ millions)	**2013**	2012	**2013**	2012
Sales from Fortis Generation to				
Other Canadian Electric Utilities	**-**	-	**1**	-
Sales from Newfoundland Power to Non-Utility	**1**	1	**4**	4
Inter-segment finance charges on lending from:				
Fortis Generation to Other Canadian Electric Utilities	**-**	-	**-**	1
Corporate to Regulated Electric Utilities - Caribbean	**1**	1	**3**	3
Corporate to Fortis Generation	**-**	-	**-**	1
Corporate to Non-Utility	**4**	4	**14**	12

The significant inter-segment asset balances were as follows:

	As at September 30	
($ millions)	**2013**	2012
Inter-segment lending from:		
Fortis Generation to Other Canadian Electric Utilities	**20**	20
Corporate to Regulated Electric Utilities - Caribbean	**83**	84
Corporate to Fortis Generation	**13**	12
Corporate to Non-Utility	**325**	284
Other inter-segment assets	**27**	25
Total inter-segment eliminations	**468**	425

17. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2013**	2012	**2013**	2012
Change in non-cash operating working capital:				
Accounts receivable	**64**	96	**190**	224
Prepaid expenses	**(20)**	(8)	**(18)**	(14)
Inventories	**(35)**	(48)	**(17)**	(21)
Regulatory assets - current portion	**29**	2	**69**	50
Accounts payable and other current liabilities	**(112)**	28	**(185)**	(39)
Regulatory liabilities - current portion	**(11)**	(13)	**14**	19
	(85)	57	**53**	219
Non-cash investing and financing activities:				
Common share dividends reinvested	**17**	15	**51**	43
Additions to utility and non-utility capital assets, and intangible assets included in current liabilities	**84**	73	**84**	73
Contributions in aid of construction included in current assets	**13**	11	**13**	11
Exercise of stock options into common shares	**-**	-	**1**	1

18. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at September 30, 2013, the Corporation's derivative contracts consisted of fuel option contracts, electricity swap contracts, natural gas swap and option contracts, and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities. Electricity swap contracts are held by Central Hudson. Gas swaps and options, and gas purchase contract premiums are held by the FortisBC Energy companies and Central Hudson.

Volume of Derivative Activity

As at September 30, 2013, the following notional volumes related to fuel option contracts and electricity and natural gas commodity derivatives that are expected to be settled are outlined below.

	2013	**2014**	**2015**	**2016**	**2017**
Fuel option contracts *(millions of imperial gallons)*	1	-	-	-	-
Electricity swap contracts *(gigawatt hours)*	221	1,095	876	439	219
Gas swaps and options *(petajoules)*	3	7	-	-	-
Gas purchase contract premiums *(petajoules)*	29	48	6	-	-

Presentation of Derivative Instruments in the Consolidated Financial Statements

On the Corporation's consolidated balance sheets, derivative instruments are presented on a net basis by counterparty, where the right of offset exists.

The Corporation's outstanding derivative balances are as follows:

	As at	
($ millions)	**September 30, 2013**	December 31, 2012
Gross derivative balances [1]	**22**	60
Netting [2]	**-**	-
Cash collateral	**-**	-
Total derivative balances [3]	**22**	60

[1] Refer to Note 19 for a discussion of the valuation techniques used to calculate the fair value of the derivative instruments.
[2] Positions, by counterparty, are netted where the intent and legal right to offset exists.
[3] Unrealized losses on commodity risk-related derivative instruments as at September 30, 2013 of $18 million were recognized in current regulatory assets (December 31, 2012 - $60 million) and $4 million were recognized in current regulatory liabilities. These unrealized losses would otherwise be recognized on the consolidated statement of comprehensive income and in accumulated other comprehensive loss.

Cash flows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

19. FAIR VALUE MEASUREMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except for those which qualify for the normal purchase and normal sale exception.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table details the estimated fair value measurements of the Corporation's financial instruments, all of which were measured using Level 2 pricing inputs, except for other investments and certain long-term debt and derivative instruments as noted below.

Asset (Liability)	**As at**			
	September 30, 2013		December 31, 2012	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset - Belize Electricity [(1)]	**105**	**n/a** [(2)]	104	n/a [(2)]
Other investments [(1) (3)]	**8**	**8**	-	-
Long-term debt, including current portion [(4)]	**(7,119)**	**(8,029)**	(5,900)	(7,338)
Waneta Partnership promissory note [(5)]	**(49)**	**(50)**	(47)	(51)
Fuel option contracts [(6)]	**-**	**-**	(1)	(1)
Electricity swap contracts [(6)]	**1**	**1**	-	-
Natural gas commodity derivatives: [(6)]				
Gas swaps and options	**(23)**	**(23)**	(51)	(51)
Gas purchase contract premiums	**-**	**-**	(8)	(8)

(1) Included in long-term other assets on the consolidated balance sheet
(2) The Corporation's expropriated investment in Belize Electricity is recognized at book value, including foreign exchange impacts. The actual amount of compensation that the Government of Belize may pay to Fortis is indeterminable at this time (Notes 20 and 22).
(3) Other investments were valued using Level 1 inputs.
(4) The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $632 million (December 31, 2012 - $150 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.
(5) Included in long-term other liabilities on the consolidated balance sheet
(6) The fair values of the derivatives were recorded in accounts payable and other current liabilities as at September 30, 2013 and December 31, 2012. The fair value of the fuel option contracts as at September 30, 2013 was less than $1 million. The fair value of electricity swap contracts was determined using Level 3 inputs.

19. FAIR VALUE MEASUREMENTS (cont'd)

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) by obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and was calculated using published market prices for heating oil or similar commodities where appropriate. The fuel option contracts matured in October 2013. Approximately 30% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The electricity swap contracts and natural gas commodity derivatives are used by Central Hudson to minimize commodity price volatility for electricity and natural gas purchases for the Company's full-service customers by fixing the effective purchase price for the defined commodities. The fair values of the electricity swap contracts and natural gas commodity derivatives were calculated using forward pricing provided by independent third parties.

The natural gas commodity derivatives are used by the FortisBC Energy companies to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas commodity derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the fuel option contracts, electricity swap contracts, and natural gas commodity derivatives are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. As at September 30, 2013, none of the fuel option contracts, electricity swap contracts and natural gas commodity derivatives were designated as hedges of fuel purchases or electricity and natural gas supply contracts. However, any gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators.

20. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk	Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity Risk	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market Risk	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at September 30, 2013, FortisAlberta's gross credit risk exposure was approximately $105 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to less than $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist. The following table summarizes the FortisBC Energy companies' net credit risk exposure to its counterparties, as well as credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as it relates to its natural gas swaps and options.

	As at	
($ millions, except as noted)	**September 30, 2013**	December 31, 2012
Gross credit exposure before credit collateral [(1)]	**23**	51
Credit collateral	**-**	-
Net credit exposure [(2)]	**23**	51
Number of counterparties > 10% (#)	**3**	4
Net exposure to counterparties > 10%	**19**	45

[(1)] Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported do not include adjustments for time value or liquidity.

[(2)] Net credit exposure is the gross credit exposure collateral minus credit collateral (cash deposits and letters of credit).

The Corporation is exposed to credit risk associated with the amount and timing of fair value compensation that Fortis is entitled to receive from the Government of Belize ("GOB") as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. As at September 30, 2013, the Corporation had a long-term other asset of $105 million (December 31, 2012 - $104 million), including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 19 and 22).

Additionally, as at September 30, 2013, Belize Electricity owed Belize Electric Company Limited ("BECOL") approximately US$8 million for energy purchases of which US$3 million was overdue (December 31, 2012 – US$8 million, of which US$7 million was overdue). In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at September 30, 2013, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $335 million, excluding borrowings under the Corporation's committed credit facility which were subsequently replaced with long-term financing (Note 24). The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at September 30, 2013, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.7 billion, of which $1.9 billion was unused, including $490 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.6 billion of the total credit facilities are committed facilities with maturities ranging from 2014 to 2018.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

				As at	
($ millions)	**Regulated Utilities**	**Non-Regulated**	**Corporate and Other**	**September 30, 2013**	December 31, 2012
Total credit facilities	**1,539**	**115**	**1,030**	**2,684**	2,460
Credit facilities utilized:					
Short-term borrowings [(1)]	**(111)**	**-**	**-**	**(111)**	(136)
Long-term debt [(2)]	**(123)**	**-**	**(509)**	**(632)**	(150)
Letters of credit outstanding	**(65)**	**-**	**(1)**	**(66)**	(67)
Credit facilities unused	**1,240**	**115**	**520**	**1,875**	2,107

(1) The weighted average interest rate on short-term borrowings was approximately 1.5% as at September 30, 2013 (December 31, 2012 - 1.9%).

(2) As at September 30, 2013, credit facility borrowings classified as long term included $50 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2012 - $62 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 2.9% as at September 30, 2013 (December 31, 2012 - 2.1%).

As at September 30, 2013 and December 31, 2012, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

In January 2013 FEVI's $20 million unsecured committed non-revolving credit facility matured and was not replaced.

In April 2013 FortisBC Electric renegotiated and amended its credit facility agreement, resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2016 and $50 million now maturing in May 2014. The amended credit facility agreement contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2013 FHI extended its $30 million unsecured committed revolving credit facility to mature in May 2014 from May 2013.

In May 2013 FortisOntario extended its $30 million unsecured revolving credit facility to mature in June 2014 from June 2013.

In June 2013 Fortis Turks and Caicos entered into new short-term unsecured demand credit facilities for US$21 million ($22 million), replacing its previous US$21 million ($22 million) facilities. The new facilities are comprised of a revolving operating credit facility of US$12 million ($12 million) and a US$9 million ($9 million) emergency standby loan. The facilities mature in June 2014, with an option to renew annually. The new credit facilities reflect a decrease in pricing but otherwise contain terms and conditions substantially similar to the previous facilities.

In July 2013 FEI, FEVI and FortisAlberta amended their $500 million, $200 million and $250 million committed revolving credit facilities, resulting in extensions to the maturity dates to August 2015, December 2015 and August 2018, respectively, from August 2014, December 2013 and August 2016, respectively. The new agreements contain substantially similar terms and conditions as the previous credit facility agreements.

In August 2013 the Corporation extended its $1 billion committed revolving corporate credit facility to mature in July 2018 from July 2015.

As at September 30, 2013, CH Energy Group had a US$100 million ($103 million) unsecured revolving credit facility maturing in October 2015, and Central Hudson had a US$150 million ($155 million) unsecured committed revolving credit facility maturing in October 2016.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at September 30, 2013, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A- (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

In February 2013 S&P and DBRS affirmed the Corporation's debt credit ratings. The above-noted credit ratings reflect the Corporation's business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. The credit ratings also reflect the Corporation's financing of the acquisition of CH Energy Group and the expected completion of the Waneta Expansion hydroelectric generating facility on time and on budget.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy Corporation, BECOL and Griffith is the US dollar.

As at September 30, 2013, the Corporation's corporately issued US$1,044 million (December 31, 2012 – US$557 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at September 30, 2013, the Corporation had approximately US$549 million (December 31, 2012 – US$17 million) in foreign net investments remaining to be hedged. Both the Corporation's US dollar-denominated long-term debt and foreign net investments as at September 30, 2013 were significantly impacted by the CH Energy Group acquisition. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective from June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis (Note 22). As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. The Corporation recognized in earnings a foreign exchange loss of $2 million for the three months ended and a foreign exchange gain of $3 million for the nine months ended September 30, 2013 ($3 million foreign exchange loss for the three and nine months ended September 30, 2012) (Note 10).

Interest Rate Risk
The Corporation and most of its subsidiaries are exposed to interest rate risk associated with credit facility borrowings. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

Commodity Price Risk
The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas; Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas; and Caribbean Utilities is exposed to commodity price risk associated with changes in the market price for fuel (Notes 18 and 19). The risks have been reduced by entering into natural gas commodity derivatives, electricity derivatives and fuel option contracts that effectively fix the price of natural gas purchases, electricity purchases and fuel purchases, respectively. The natural gas and electricity derivatives and fuel option contracts are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates.

20. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)
The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, mitigate gas price volatility on customer rates and reduce the risk of regional price discrepancies. As directed by the regulator in 2011, the FortisBC Energy companies have suspended their commodity hedging activities with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

21. COMMITMENTS

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2012 annual audited consolidated financial statements, except as follows.

Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit. A major refurbishment of Point Lepreau that began in 2008 was completed and the station returned to service in November 2012. The refurbishment is expected to extend the facility's estimated life an additional 27 years and, as a result, the total estimated capital cost obligation has increased approximately $96 million from that disclosed in the 2012 annual audited consolidated financial statements.

In May 2013 FortisBC Electric entered into a new Power Purchase Agreement ("PPA") with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013. This new PPA does not change the basic parameters of the BC Hydro PPA, which expired on September 30, 2013. An executed version of the PPA was submitted by BC Hydro to the BCUC in May 2013 and is pending regulatory approval. In the interim period until the new PPA is approved by the BCUC, FortisBC Electric and BC Hydro have agreed to continue under the terms of the expired BC Hydro PPA. Power purchases in the interim are approved for recovery in customer rates. The power purchases from the new PPA are expected to be recovered in customer rates.

Central Hudson is party to various gas purchase contracts with obligations totaling approximately $126 million as at September 30, 2013. These obligations are based on tariff rates as at September 30, 2013.

Central Hudson is also party to agreements with Entergy Nuclear Power Marketing, LLC to purchase electricity, and not capacity, on a unit-contingent basis at defined prices from January 1, 2011 through December 31, 2013. Central Hudson must also acquire sufficient peak load capacity to meet the peak load requirements of its full-service customers. This capacity requirement is met through contracts with capacity providers, purchases from the New York Independent System Operator capacity market and the Company's own generating capacity. Obligations in respect of electricity purchase agreements totalled $42 million as at September 30, 2013.

Central Hudson has various purchase commitments and contracts related to ongoing projects and operating activities with an obligation totalling approximately $119 million as at September 30, 2013.

22. EXPROPRIATED ASSETS

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by independent valuators. The GOB also commissioned a valuation of Belize Electricity which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset.

In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision is pending. Any decision of the Belize Court of Appeal may be appealed to the Caribbean Court of Justice, the highest court of appeal available for judicial matters in Belize.

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a reasonable possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. The book value was $105 million, including foreign exchange impacts, as at September 30, 2013 (December 31, 2012 - $104 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis, for example: (i) the ordering of the return of the shares to Fortis and/or award of damages; or (ii) the ordering of compensation to be paid to Fortis for the unconstitutional expropriation of the shares. Based on presently available information, the $105 million long-term other asset is not deemed impaired as at September 30, 2013. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/United Kingdom Bilateral Investment Treaty.

23. CONTINGENT LIABILITIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval.

23. CONTINGENT LIABILITIES (cont'd)

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from CRA for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. A settlement was reached with CRA in the second quarter of 2013 resulting in the release of income tax provisions of approximately $5 million (Note 12).

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake in 2003, prior to the acquisition of FortisBC Electric by Fortis, and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which includes FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the utility has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

Central Hudson

Danskammer Point Steam Electric Generating Station

In 1999, the New York State Attorney General alleged that Central Hudson may have constructed, and continued to operate, major modifications to the Danskammer Point Steam Electric Generating Station ("Danskammer Plant") without obtaining certain requisite pre-construction permits. In March 2000, the Environmental Protection Agency assumed responsibility for the investigation. Central Hudson believes any permits required for these projects were obtained in a timely manner. The Company sold the Danskammer Plant to Dynegy Inc. in January 2001. While Central Hudson could have retained liability after the sale, depending on the type of remedy, the Company believes that the statutes of limitation relating to any alleged violation of air emissions rules have lapsed.

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800's with all sites ceasing operations by the 1950's. This process produced certain by-products that may pose risks to human health and the environment.

23. CONTINGENT LIABILITIES (cont'd)

Central Hudson (cont'd)
Former MGP Facilities (cont'd)
The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement, or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at September 30, 2013, an obligation of US$8 million was recognized in respect of MGPs remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$152 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, the differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return (Note 4).

Eltings Corners
Central Hudson owns and operates a maintenance and warehouse facility. In the course of Central Hudson's hazardous waste permit renewal process for this facility, sediment contamination was discovered within the wetland area across the street from the main property. In cooperation with the DEC, Central Hudson continues to investigate the nature and extent of the contamination. The extent of the contamination, as well as the timing and costs for any future remediation efforts, cannot be reasonably estimated at this time and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

Asbestos Litigation
Prior to the acquisition of CH Energy Group, various asbestos lawsuits had been brought against Central Hudson. While a total of 3,341 asbestos cases have been raised, 1,169 remained pending as at September 30, 2013. Of the cases no longer pending against Central Hudson, 2,017 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 155 cases. The Company is presently unable to assess the validity of the remaining asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the interim unaudited consolidated financial statements.

24. SUBSEQUENT EVENT

In October 2013 the Corporation issued 10-year US$285 million unsecured notes at 3.84% and 30-year US$40 million unsecured notes at 5.08%. Proceeds from the offering were used to repay a portion of the Corporation's US dollar-denominated credit facility borrowings incurred to initially finance a portion of the CH Energy Group acquisition and for general corporate purposes.

25. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation.

Dates – Dividends* and Earnings

Expected Earnings Release Dates

February 6, 2014	May 8, 2014
August 1, 2014	November 7, 2014

Dividend Record Dates

November 15, 2013	February 14, 2014
May 16, 2014	August 15, 2014

Dividend Payment Dates

December 1, 2013	March 1, 2014
June 1, 2014	September 1, 2014

* *The declaration and payment of dividends are subject to Board of Directors' approval.*

Registrar and Transfer Agent

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514-982-7555 or 1-866-586-7638
F: 416-263-9394 or 1-888-453-0330
W: www.investorcentre.com/fortisinc

Share Listings

The Common Shares, First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and First Preference Shares, Series K of Fortis are traded on the Toronto Stock Exchange under the symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J and FTS.PR.K, respectively.

Fortis Common Shares ($) Quarter Ended September 30		
	2013	**2012**
High	**32.95**	**34.03**
Low	**29.78**	**32.37**
Close	**31.29**	**33.53**

FORTIS INC.

The Fortis Building
Suite 1201, 139 Water Street
PO Box 8837
St. John's, NL Canada A1B 3T2

T: 709.737.2800
F: 709.737.5307

www.fortisinc.com
TSX:FTS