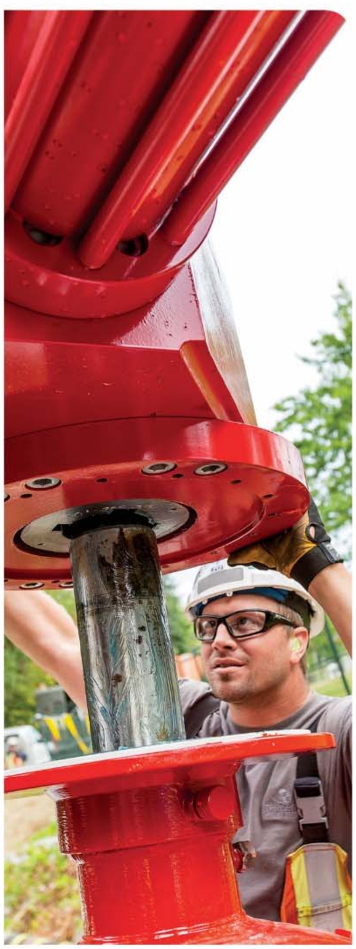
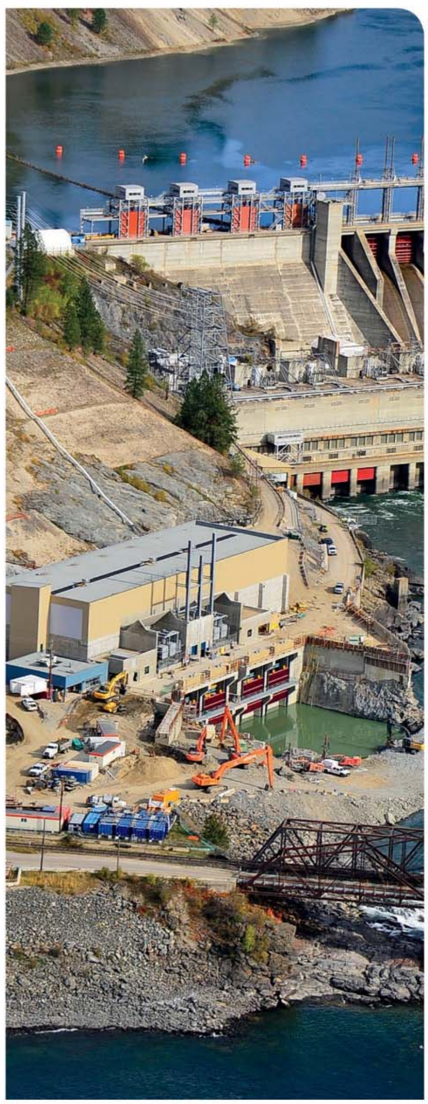
Third Quarter 2015





Dear Fortis Shareholder:

Strong results earnings and cash flow; capital expenditures on track

Fortis had strong financial and operational results for the third quarter of 2015, delivering net earnings attributable to common equity shareholders of $151 million or $0.54 per common share, compared to $14 million, or $0.06 per common share, for the third quarter of 2014.

These results were driven by our U.S. utility acquisitions, including a full quarter's contribution from UNS Energy, which was acquired in mid-August 2014; a $5 million contribution from the Waneta Expansion, which came online in early April 2015; higher capital tracker revenue and customer growth at FortisAlberta; and the resetting of customer rates at Central Hudson, effective July 1, 2015. The continued strength of the U.S. dollar relative to the Canadian dollar and lower operating expenses and a higher equity component of allowance for funds used during construction at FortisBC Energy also contributed to earnings growth.

Cash flow from operating activities for the first nine months of 2015 totalled $1.3 billion, almost double compared to the same period last year due to the acquisition of UNS Energy. After considering the closing of the sale of hotels in October 2015, proforma unused credit facilities totalled approximately $2.3 billion as at September 30, 2015. Almost $400 million in debt was raised at the regulated utilities in the quarter, and $1.0 billion was raised year to date, at attractive interest rates. Capital expenditures were $0.5 billion in the quarter and $1.7 billion year to date, with consolidated capital expenditures for 2015 forecasted to be approximately $2.2 billion, a record for Fortis.

During the quarter, we settled with the Government of Belize regarding their expropriation of the Corporation's approximate 70% interest in Belize Electricity Limited in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the Government of Belize and an approximate 33% equity investment in Belize Electricity.

After the sale of the commercial real estate and hotel assets in mid-October, as well as the disposition of non-regulated generation assets in New York and Ontario, substantially all of Fortis' assets are comprised of regulated utilities and long-term contracted energy infrastructure. Net proceeds of almost $900 million from these sales were used to repay credit facility borrowings, largely associated with the acquisition of UNS Energy, and for other general corporate purposes.

Regulatory Matters

In November 2015 Tucson Electric Power Company, UNS Energy's largest utility, filed a general rate application with the Arizona Corporation Commission requesting new retail rates to be effective January 1, 2017, using June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, its total rate base has increased by approximately U.S.$0.6 billion and the common equity component of capital structure increased from approximately 43.5% to approximately 50%.

At our Canadian utilities, Newfoundland Power and Maritime Electric recently filed general rate applications for 2016 and FortisBC Energy, the benchmark utility in British Columbia, filed its application to review cost of capital for 2016. The regulator in Alberta has also initiated a generic cost of capital proceeding for 2016 and 2017, which will impact FortisAlberta.

Outlook

During the third quarter of 2015, Fortis initiated dividend guidance. We are targeting annual dividend growth of 6% through 2020 based on a 2016 dividend of $1.50. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at our utilities, the successful execution of our $9 billion five-year capital plan, and management's continued confidence in the strength of our diversified portfolio of assets and record of operational excellence. At the same time, Fortis also increased its dividend per common share in the third quarter to over 10% to $0.375 per quarter, or $1.50 on an annualized basis. This increase follows a 6.25% increase that was implemented in March 2015.

Our focus, and virtually all of Fortis' assets, are low-risk, regulated utility businesses and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one third of total assets.

Over the next five-year period through 2020, our capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to approximately $20 billion in 2020 and produce a five-year compound annual growth rate of approximately 4.5%. In addition to the base capital expenditure program, Fortis is pursuing additional investment opportunities in existing and new franchise areas, including further investment in natural gas-related infrastructure. We expect this capital investment to support growth in earnings and dividends.

Focusing on value creation through sustained profitable growth

In closing, 2015 is positioning us for sustained profitable growth. We believe building on the strength of our core business and further diversifying our asset base in regulated utilities – including investing in additional energy infrastructure opportunities, and executing on a robust capital expenditure plan – will help achieve this.

We feel very well positioned to deliver good returns to our shareholders over the long term.

Barry V. Perry
President and Chief Executive Officer
Fortis Inc.

Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2015

Dated November 6, 2015

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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, 2015 and the MD&A and audited consolidated financial statements for the year ended December 31, 2014 included in the Corporation's 2014 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 MD&A within the meaning of applicable securities laws in Canada. 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. Forward-looking statements are typically identified by words such as *"anticipates", "budgets", "could", "estimates", "expects", "forecasts", "may", "might", "opportunity", "projects", "pending", "schedule", "should", "target", "would" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements included in the MD&A include, but are not limited to, statements related to the annualized 2016 common share dividend; targeted annual dividend growth through 2020; the expectation that midyear rate base will increase from 2015 to 2020; the Corporation's forecast gross consolidated capital expenditures for 2015 and total capital spending for the period from 2016 through 2020; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas ("LNG") facility expansion, the pipeline expansion to the Woodfibre LNG site, the development of a diesel power plant in Grand Cayman, the Pinal transmission project in Arizona and additional opportunities including electric transmission, LNG and renewable related infrastructure and generation; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; 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 Corporation's subsidiaries will be able to source the cash required to fund their 2015 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated fixed-term debt maturities and repayments in 2015 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long terms; 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 expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2015; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; and the expectation that the adoption of future accounting or tax pronouncements will not have a material impact on the Corporation's consolidated financial statements.*

Forward-looking statements involve significant risk, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations. Such risk factors or assumptions include, but are not limited to, reasonable decisions by regulators; the implementation of the Corporation's five-year plan; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; fluctuating foreign exchange; the Board exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; 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 electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity 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, coal 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; new or revised environmental laws and regulations will not severely affect the results of operations; 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 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; no significant changes in tax legislation; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements.

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 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. 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 a leader in the North American electric and gas utility business, with total assets of almost $29 billion and fiscal 2014 revenue of $5.4 billion. Its regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis also owns long-term contracted hydroelectric generation assets in British Columbia and Belize.

Year-to-date September 30, 2015, the Corporation's electricity distribution systems met a combined peak demand of 9,685 megawatts ("MW") and its gas distribution system met a peak day demand of 1,198 terajoules. 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, 2015 and to the "Corporate Overview" section of the 2014 Annual MD&A.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas 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. If a historical test year is used to set customer rates, which is the situation at UNS Energy Corporation ("UNS Energy"), there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When 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 prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common 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; (vi) regulatory lag in the case of a historical test year; and (vii) timing differences within an annual financial reporting period between when actual expenses are incurred and when they are recovered from customers in rates. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the 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.

SIGNIFICANT ITEMS

Settlement of Belize Electricity Limited Expropriation Matters: In August 2015 the Corporation agreed to terms of a settlement with the Government of Belize ("GOB") regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity Limited ("Belize Electricity") in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in the third quarter.

Sale of Commercial Real Estate and Hotel Assets: In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties Corporation ("Fortis Properties") for gross proceeds of $430 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $109 million, net of expenses, in the second quarter. As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. Net proceeds from the sale were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As at September 30, 2015, the associated assets have been classified as held for sale on the Corporation's interim unaudited consolidated balance sheet. As a result, the Corporation recognized an approximate $8 million after-tax loss year-to-date 2015, which includes an impairment loss and expenses associated with the sale transaction. Net proceeds from the sale were used by the Corporation to repay credit facility borrowings and for other general corporate purposes.

Sale of Non-Regulated Generation Assets in New York and Ontario: In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized an after-tax gain of approximately $27 million (US$22 million), net of expenses and foreign exchange impacts, in the second quarter.

In July 2015 the Corporation closed the sale of its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $5 million in the third quarter.

Completion of the Waneta Expansion Hydroelectric Generating Facility: On April 1, 2015, the Corporation completed construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility (the "Waneta Expansion") ahead of schedule and on budget. Fortis has a 51% controlling ownership interest in the Waneta Expansion, with Columbia Power Corporation and Columbia Basin Trust holding the remaining 49% interest. The Waneta Expansion contributed $17 million in earnings to the Corporation year-to-date 2015. For further information regarding the Waneta Expansion, refer to the "Non-Regulated – Fortis Generation" and "Capital Expenditure Program" sections of this MD&A.

Regulatory Decisions and Applications: The information below highlights the most significant regulatory decisions and applications of the Corporation's utilities year-to-date 2015. For further details, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

In November 2015 Tucson Electric Power Company ("TEP"), UNS Energy's largest utility, filed a general rate application ("GRA") with the Arizona Corporation Commission ("ACC") requesting new retail rates to be effective January 1, 2017, using June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from approximately 43.5% to approximately 50%.

In June 2015 the New York State Public Service Commission ("PSC") issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US$225 million in energy infrastructure during the two-year delivery rate freeze period ending June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure and includes continuation of revenue decoupling and earnings sharing mechanisms.

In March 2015 regulatory decisions were received on FortisAlberta Inc.'s ("FortisAlberta") Capital Tracker Applications and the Generic Cost of Capital ("GCOC") Proceeding in Alberta. As a result of these regulatory decisions, in the first half of 2015, FortisAlberta recognized a positive $9 million capital tracker revenue adjustment associated with 2013 and 2014.

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with the primary measures of financial performance being earnings per common share and total shareholder return. 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, 2015 and 2014 are provided in the following table.

Consolidated Financial Highlights (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions, except for common share data)	**2015**	2014	Variance	**2015**	2014	Variance
Revenue	**1,566**	1,197	369	**5,019**	3,708	1,311
Energy Supply Costs	**533**	406	127	**1,897**	1,488	409
Operating Expenses	**461**	384	77	**1,392**	1,010	382
Depreciation and Amortization	**217**	181	36	**652**	478	174
Other Income (Expenses), Net	**5**	(43)	48	**188**	(37)	225
Finance Charges	**141**	159	(18)	**416**	406	10
Income Tax Expense (Recovery)	**40**	(8)	48	**173**	40	133
Earnings from Continuing Operations	**179**	32	147	**677**	249	428
Earnings from Discontinued Operations, Net of Tax	**-**	-	-	**-**	5	(5)
Net Earnings	**179**	32	147	**677**	254	423
Net Earnings Attributable to:						
Non-Controlling Interests	**9**	3	6	**26**	8	18
Preference Equity Shareholders	**19**	15	4	**58**	42	16
Common Equity Shareholders	**151**	14	137	**593**	204	389
Net Earnings	**179**	32	147	**677**	254	423
Earnings per Common Share from Continuing Operations						
Basic *($)*	**0.54**	0.06	0.48	**2.13**	0.93	1.20
Diluted *($)*	**0.54**	0.06	0.48	**2.11**	0.93	1.18
Earnings per Common Share						
Basic *($)*	**0.54**	0.06	0.48	**2.13**	0.95	1.18
Diluted *($)*	**0.54**	0.06	0.48	**2.11**	0.95	1.16
Weighted Average Common Shares Outstanding *(# millions)*	**279.1**	215.6	63.5	**277.9**	214.6	63.3
Cash Flow from Operating Activities	**358**	62	296	**1,276**	648	628

Revenue

The increase in revenue for the quarter and year to date was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher revenue at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by a decrease in the commodity cost of natural gas charged to customers at FortisBC Energy and a decrease in non-utility revenue due to the sale of commercial real estate assets in June 2015.

Energy Supply Costs

The increase in energy supply costs for the quarter and year to date was primarily due to the acquisition of UNS Energy and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs. The increase was partially offset by a lower commodity cost of natural gas at FortisBC Energy.

Operating Expenses

The increase in operating expenses for the quarter and year to date was primarily due to the acquisition of UNS Energy, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate assets in June 2015 and lower retirement expenses. Retirement expenses of approximately $9 million ($8 million after tax) and $13 million ($11 million after tax) were recognized in the third quarter and year-to-date 2014, respectively, compared to approximately $2 million ($1 million after tax) recognized year-to-date 2015.

Depreciation and Amortization

The increase in depreciation and amortization for the quarter and year to date was primarily due to the acquisition of UNS Energy and continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income (Expenses), Net

The increase in other income, net of expenses, for the quarter was primarily due to acquisition-related expenses associated with UNS Energy recognized in the third quarter of 2014.

The increase in other income, net of expenses, year to date was primarily due to gains on the sale of commercial real estate and non-regulated generation assets year-to-date 2015 and acquisition-related expenses associated with UNS Energy recognized year-to-date 2014. The increase was partially offset by a loss associated with the sale of hotel assets year-to-date 2015.

Finance Charges

The decrease in finance charges for the quarter was primarily due to lower interest on convertible debentures. Approximately $33 million ($23 million after tax) and $67 million ($47 million after tax) in interest expense for the quarter and year to date, respectively, was recognized in 2014 associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. In October 2014 the convertible debentures were substantially all converted into common shares of the Corporation. The decrease was partially offset by finance charges associated with the acquisition of UNS Energy, including interest expense on debt issued to complete the financing of the acquisition, and unfavorable foreign exchange associated with the translation of US-dollar denominated interest expense.

The increase in finance charges year to date was primarily due to the acquisition of UNS Energy, as discussed above for the quarter, and unfavorable foreign exchange associated with the translation of US-dollar denominated interest expense. The increase was partially offset by lower interest on convertible debentures, as discussed above for the quarter.

Income Tax Expense

The increase in income tax expense for the quarter was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy. The increase was partially offset by a deferred income tax recovery associated with the sale of hotel assets.

The increase in income tax expense year to date was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy and gains on the sale of commercial real estate and non-regulated generation assets. The increase was partially offset by a deferred income tax recovery associated with the sale of hotel assets.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings Per Common Share

Net earnings attributable to common equity shareholders were impacted by a number of non-recurring items or non-operating factors. These factors, referred to as adjusting items, are reconciled below and discussed in the segmented results of operations for the respective reporting segments. Management believes that adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share provides useful information to investors and shareholders as it provides increased transparency and predictive value. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions, except for common share data)	**2015**	2014	Variance	**2015**	2014	Variance
Net Earnings Attributable to Common Equity Shareholders	**151**	14	137	**593**	204	389
Adjusting Items:						
FortisAlberta -						
Capital tracker revenue adjustment for 2013 and 2014	**-**	-	-	**(9)**	-	(9)
Non-Regulated - Fortis Generation -						
Gain on sale of generation assets	**(5)**	-	(5)	**(32)**	-	(32)
Non-Utility -						
Gain on sale of commercial real estate assets	**-**	-	-	**(109)**	-	(109)
(Gain) loss on sale of hotel assets	**(5)**	-	(5)	**8**	-	8
Earnings from discontinued operations	**-**	-	-	**-**	(5)	5
Corporate and Other -						
Foreign exchange gain	**(5)**	(5)	-	**(13)**	(5)	(8)
Loss on settlement of expropriation matters	**9**	-	9	**9**	-	9
Interest expense on convertible debentures	**-**	23	(23)	**-**	47	(47)
Acquisition-related expenses	**-**	35	(35)	**-**	38	(38)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**145**	67	78	**447**	279	168
Adjusted Basic Earnings Per Common Share *($)*	**0.52**	0.31	0.21	**1.61**	1.30	0.31

The increase in adjusted net earnings attributable to common equity shareholders for the quarter and year to date was driven by earnings contribution of $97 million and $169 million, respectively, at UNS Energy compared to $37 million for the third quarter and year-to-date 2014. Earnings contribution of $5 million and $17 million for the third quarter and year-to-date 2015, respectively, from the Waneta Expansion, which represents the Corporation's 51% controlling ownership, also contributed to the increase. Performance for the quarter and year to date was also driven by the Corporation's other regulated utilities, including higher capital tracker revenue for 2015 and customer growth at FortisAlberta; improved performance at Central Hudson; and favourable foreign exchange associated with US dollar-denominated earnings. Earnings at FortisBC Energy and FortisBC Electric were impacted by the timing of regulatory deferral mechanisms; however, FortisBC Energy's earnings for the quarter and year to date were favourably impacted by lower operating expenses and a higher equity component of allowance for funds used during construction ("AFUDC"). The increase in adjusted earnings for the quarter and year to date was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy.

The increase in adjusted earnings per common share for the quarter and year to date was driven by accretion associated with the acquisition of UNS Energy, after considering the finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. Performance at the Corporation's other regulated utilities, as discussed above, contribution from the Waneta Expansion, and the impact of favourable foreign exchange also contributed to the increase.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended September 30		**Quarter**			**Year-to-Date**	
($ millions)	**2015**	2014	Variance	**2015**	2014	Variance
Regulated Electric & Gas Utilities - United States						
UNS Energy	***97***	*37*	*60*	***169***	*37*	*132*
Central Hudson	***11***	*8*	*3*	***43***	*33*	*10*
	108	45	63	**212**	70	142
Regulated Gas Utility - Canadian						
FortisBC Energy	**(20)**	(13)	(7)	**75**	78	(3)
Regulated Electric Utilities - Canadian						
FortisAlberta	***37***	*27*	*10*	***109***	*78*	*31*
FortisBC Electric	***8***	*9*	*(1)*	***42***	*34*	*8*
Eastern Canadian	***13***	*13*	*-*	***47***	*46*	*1*
	58	49	9	**198**	158	40
Regulated Electric Utilities - Caribbean	**11**	8	3	**25**	21	4
Non-Regulated - Fortis Generation	**18**	4	14	**66**	16	50
Non-Regulated - Non-Utility	**11**	9	2	**113**	21	92
Corporate and Other	**(35)**	(88)	53	**(96)**	(160)	64
Net Earnings Attributable to Common Equity Shareholders	**151**	14	137	**593**	204	389

The following is a discussion of the financial results of the Corporation's reporting segments. Refer to the "Material Regulatory Decisions and Applications" section of this MD&A for a discussion pertaining to the Corporation's regulated utilities.

REGULATED ELECTRIC & GAS UTILITIES - UNITED STATES

UNS ENERGY [(1)]

Financial Highlights (Unaudited) [(2)]		**Quarter**			**Year-to-Date**	
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Average US:CDN Exchange Rate [(3)]	**1.31**	1.09	0.22	**1.26**	1.09	0.17
Electricity Sales *(gigawatt hours ("GWh"))*	**4,426**	2,063	2,363	**11,804**	2,063	9,741
Gas Volumes *(petajoules ("PJ"))*	**2**	1	1	**9**	1	8
Revenue *($ millions)*	**623**	249	374	**1,552**	249	1,303
Earnings *($ millions)*	**97**	37	60	**169**	37	132

(1) Primarily includes TEP, UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), acquired by Fortis in August 2014

(2) Financial highlights for 2014 are from the date of acquisition in August 2014.

(3) The reporting currency of UNS Energy is the US dollar.

Electricity Sales & Gas Volumes

Electricity sales for the third quarter were 4,426 gigawatt hours ("GWh") compared to 4,219 GWh for the full quarter last year and 11,804 GWh for the first nine months of 2015 compared to 10,977 GWh for the full nine months of 2014. The increase was primarily due to higher short-term wholesale sales. The majority of short-term wholesale sales is flowed through to customers and has no impact on earnings. Retail sales were comparable quarter over quarter. The year-to-date increase was partially offset by lower retail sales as a result of a decrease in industrial and commercial load.

Gas volumes for the quarter and year to date were comparable with the same periods last year.

Seasonality impacts the earnings of UNS Energy. Earnings for the electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment and earnings for the gas utility are generally highest in the first and fourth quarters due to space-heating requirements. In 2014 approximately 75% of UNS Energy's earnings were recognized in the second and third quarters, excluding acquisition-related expenses.

Revenue

Revenue for the quarter and year to date was US$476 million and US$1,228 million, respectively, compared to US$457 million and US$1,177 million, respectively, for the same periods last year. The increase was primarily due to the flow through to customers of higher purchased power and fuel supply costs, higher wholesale electricity sales, higher transmission revenue and an increase in lost fixed cost recovery revenue. The year-to-date increase was partially offset by lower retail electricity sales.

Earnings

Earnings for the quarter and year to date were US$74 million and US$132 million, respectively, compared to US$67 million and US$123 million for the same periods last year, excluding the impact of acquisition-related expenses. The increase was primarily due to higher transmission revenue, an increase in lost fixed cost recovery revenue, and a decrease in interest expense due to the expiry of leasing arrangements. The year-to-date increase was partially offset by higher operating expenses.

CENTRAL HUDSON

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Average US:CDN Exchange Rate [(1)]	**1.31**	1.09	0.22	**1.26**	1.09	0.17
Electricity Sales *(GWh)*	**1,340**	1,323	17	**3,972**	3,899	73
Gas Volumes *(PJ)*	**4**	3	1	**19**	18	1
Revenue *($ millions)*	**193**	173	20	**678**	635	43
Earnings *($ millions)*	**11**	8	3	**43**	33	10

[(1)] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The increase in electricity sales for the quarter and year to date was due to higher average consumption as a result of warmer temperatures. Gas volumes for the quarter and year to date were comparable with the same periods last year.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

Seasonality impacts delivery revenue at 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.

Revenue

The increase in revenue for the quarter and year to date was driven by approximately $32 million and $83 million, respectively, of favourable foreign exchange associated with the translation of US dollar-denominated revenue. An increase in base electricity rates effective July 1, 2015 and the recovery from customers of previously deferred electricity costs also contributed to the increase in revenue. Additionally, revenue for the first half of 2015 was favourably impacted by energy efficiency incentives and higher gas revenue associated with a new gas delivery contract in late 2014. The increase in revenue for the quarter and year to date was partially offset by the recovery from customers of lower commodity costs, which were mainly due to lower wholesale prices.

Earnings

The increase in earnings for the quarter was primarily due to approximately $2 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and an increase in base electricity rates effective July 1, 2015.

The increase in earnings year to date was primarily due to approximately $6 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings. An increase in base electricity rates effective July 1, 2015, a new gas delivery contract in late 2014 and energy efficiency incentives earned during the first half of 2015 also contributed to the increase in earnings. The increase was partially offset by the impact of higher expenses during the two-year rate freeze period post acquisition, which ended on June 30, 2015.

REGULATED GAS UTILITY - CANADIAN

FORTISBC ENERGY [(1)]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Gas Volumes *(PJ)*	**26**	25	1	**124**	136	(12)
Revenue *($ millions)*	**168**	208	(40)	**884**	1,003	(119)
(Loss) Earnings *($ millions)*	**(20)**	(13)	(7)	**75**	78	(3)

(1) Primarily includes FortisBC Energy Inc. ("FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company.

Gas Volumes

Gas volumes for the quarter were comparable with the same period last year. The decrease in gas volumes year to date was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

FortisBC Energy earns 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 regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas do not materially affect earnings.

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

Revenue

The decrease in revenue for the quarter and year to date was primarily due to a lower commodity cost of natural gas charged to customers, amounts owing to customers under the earnings sharing mechanism, and the timing of regulatory flow-through deferral amounts. Prior to the amalgamation of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEWI") on December 31, 2014, FEVI was subject to a rate stabilization mechanism which accumulated the difference between revenue received and actual cost of service, thereby reducing the seasonality of revenue and earnings. As a result of the amalgamation, effective January 1, 2015, this rate stabilization mechanism ceased, resulting in greater seasonality whereby revenue and earnings will be higher in the first and fourth quarters and lower in the second and third quarters. Lower gas volumes also had an unfavourable impact on revenue year to date.

(Loss) Earnings

The higher loss for the quarter and decrease in earnings year to date were mainly due to approximately $13 million and $9 million, respectively, associated with the timing of regulatory flow-through deferral amounts, as discussed above, and a decrease in the allowed ROE and equity component of capital structure as a result of the amalgamation of FEVI and FEWI with FEI, effective December 31, 2014. Prior to the amalgamation, the allowed ROEs for FEVI and FEWI were 9.25% and 9.50%, respectively, on a common equity component of capital structure of 41.5%. Effective January 1, 2015, the allowed ROE and common equity component of capital structure reverted to those of FEI, which are 8.75% and 38.5%, respectively. The decrease was partially offset by lower operating expenses, net of the regulatory earnings sharing mechanism, and a higher equity component of AFUDC.

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Energy Deliveries *(GWh)*	**4,251**	4,152	99	**12,944**	12,926	18
Revenue *($ millions)*	**141**	131	10	**423**	386	37
Earnings *($ millions)*	**37**	27	10	**109**	78	31

Energy Deliveries
The increase in energy deliveries for the quarter and year to date was primarily due to higher average consumption by residential, commercial and farm and irrigation customers, mainly due to warmer temperatures, and growth in the number of residential and commercial customers. Lower levels of precipitation also had a favorable impact on energy deliveries to farm and irrigation customers for the quarter. The increase was partially offset by lower average consumption by oil and gas customers due to low commodity prices for oil and gas.

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.

Revenue
The increase in revenue for the quarter was primarily due to the operation of the PBR formula, including an increase in customer rates based on a combined inflation and productivity factor of 1.49%, higher 2015 capital tracker revenue, growth in the number of customers, and higher revenue related to flow-through costs to customers.

The increase in revenue year to date was due to the same factors discussed above for the quarter, combined with a positive $9 million capital tracker revenue adjustment recognized in the first half of 2015 associated with 2013 and 2014, as discussed below.

In March 2015 regulatory decisions were received on FortisAlberta's Capital Tracker Applications and the GCOC Proceeding in Alberta. The Capital Tracker Decision approved revenue for substantially all of FortisAlberta's capital programs as filed; previously, revenue was recognized on an interim basis at 60% of the applied for amounts. The GCOC Proceeding set the utility's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The impact of the changes in the allowed ROE and common equity component of capital structure only applies to the portion of FortisAlberta's revenue that is funded by capital tracker revenue throughout the term of the PBR regulation. The $9 million capital tracker revenue adjustment associated with 2013 and 2014 reflects the combined impact of the Capital Tracker Decision and the GCOC Decision, taking into consideration the capital tracker revenue previously recognized on an interim basis for 2013 and 2014 at 60% of the applied for amounts. For further details on these regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Earnings
The increase in earnings for the quarter and year to date was primarily due to rate base growth and associated 2015 capital tracker revenue, growth in the number of customers and a decrease in depreciation and amortization as a result of a technical update to FortisAlberta's last depreciation study. Also contributing to the increase in earnings year to date was capital tracker revenue of approximately $9 million recognized in the first half of 2015 associated with 2013 and 2014, as discussed above.

FORTISBC ELECTRIC [1]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Electricity Sales *(GWh)*	**742**	732	10	**2,280**	2,333	(53)
Revenue *($ millions)*	**85**	78	7	**261**	244	17
Earnings *($ millions)*	**8**	9	(1)	**42**	34	8

[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 Walden Power Partnership.

Electricity Sales
The increase in electricity sales for the quarter was mainly due to higher average consumption as a result of changes in temperatures. The decrease in electricity sales year to date was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

Revenue
The increase in revenue for the quarter was driven by increases in base electricity rates, electricity sales growth and surplus capacity sales. Revenue was also favourably impacted by higher contribution from non-regulated operating, maintenance and management services.

The increase in revenue year to date was due to the same factors discussed above for the quarter, partially offset by a decrease in electricity sales.

Earnings
The decrease in earnings for the quarter was primarily due to the timing of earnings compared to the same period last year as a result of the impact of regulatory deferral mechanisms, as well as the timing of power purchase costs. The decrease was partially offset by higher earnings from non-regulated operating, maintenance and management services.

The increase in earnings year to date was primarily due to timing differences, as discussed above for the quarter, which had the opposite effect on year-to-date earnings, rate base growth, and higher earnings from non-regulated operating, maintenance and management services. The increases in base electricity rates were mainly established to recover higher power purchase costs, which commenced in the second quarter of 2015.

EASTERN CANADIAN ELECTRIC UTILITIES [1]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Electricity Sales *(GWh)*	**1,543**	1,529	14	**6,214**	6,173	41
Revenue *($ millions)*	**206**	198	8	**760**	742	18
Earnings *($ millions)*	**13**	13	-	**47**	46	1

[1] Comprised of Newfoundland Power Inc., Maritime Electric Company, Limited and FortisOntario Inc. ("FortisOntario"). FortisOntario mainly includes Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company, Limited, and Algoma Power Inc.

Electricity Sales
The increase in electricity sales for the quarter and year to date was primarily due to customer growth in Newfoundland, as well as higher average consumption on Prince Edward Island, mainly due to an increase in the number of customers using electricity for home heating. The year-to-date increase was partially offset by lower average consumption in Ontario.

Revenue
The increase in revenue for the quarter and year to date was mainly due to the flow through in customer electricity rates of higher energy supply costs and electricity sales growth. The increase was partially offset by a higher regulatory rate of return adjustment at Maritime Electric for the quarter and year-to-date 2015 compared to the same periods last year, and lower electricity sales in Ontario.

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

The increase in earnings year to date was primarily due to electricity sales growth and lower operating costs, mainly due to restoration efforts at Newfoundland Power following the loss of energy supply from Newfoundland and Labrador Hydro and related power interruptions in January 2014. The increase was partially offset by $1 million in business development costs in Ontario.

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Average US:CDN Exchange Rate [(2)]	**1.31**	1.09	0.22	**1.26**	1.09	0.17
Electricity Sales *(GWh)*	**219**	207	12	**601**	584	17
Revenue *($ millions)*	**87**	85	2	**239**	237	2
Earnings *($ millions)*	**11**	8	3	**25**	21	4

[(1)] Comprised of Caribbean Utilities Company, Ltd. ("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 and Turks and Caicos Utilities Limited (collectively "Fortis Turks and Caicos"). Also includes the Corporation's 33% equity investment in Belize Electricity. For further information refer to the "Significant Items" section of this MD&A.

[(2)] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales
The increase in electricity sales for the quarter and year to date was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures, which increased air conditioning load.

Revenue
The increase in revenue for the quarter and year to date was primarily due to approximately $13 million and $30 million, respectively, of favourable foreign exchange associated with the translation of US dollar-denominated revenue, and electricity sales growth. The increase was partially offset by the flow through in customer electricity rates of lower fuel costs at Caribbean Utilities.

Earnings
The increase in earnings for the quarter and year to date was due to approximately $2 million and $3 million, respectively, of favourable foreign exchange associated with the translation of US dollar-denominated earnings, electricity sales growth and higher capitalized interest at Caribbean Utilities, partially offset by higher depreciation.

NON-REGULATED - FORTIS GENERATION [1]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2015**	2014	Variance	**2015**	2014	Variance
Energy Sales *(GWh)*	**170**	77	93	**722**	298	424
Revenue *($ millions)*	**29**	8	21	**77**	30	47
Earnings *($ millions)*	**18**	4	14	**66**	16	50

[1] Primarily comprised of hydroelectric generation assets in British Columbia and Belize, with a combined generating capacity of 407 MW. On April 1, 2015, the Corporation completed construction of the $900 million, 335-MW Waneta Expansion. For further information, refer to the “Capital Expenditure Program” section of this MD&A. Non-regulated generation assets in Upstate New York and Ontario were sold in June 2015 and July 2015, respectively. For further information, refer to the “Significant Items” section of this MD&A.

Energy Sales

The increase in energy sales for the quarter was driven by the Waneta Expansion, which commenced production on April 2, 2015 and reported energy sales of 88 GWh for the third quarter. Increased production in Belize due to higher rainfall early in the quarter also contributed to the increase, which was partially offset by decreased production in Upstate New York and Ontario due to the sale of generation assets in June 2015 and July 2015, respectively.

The increase in energy sales year to date was driven by the Waneta Expansion, as discussed above for the quarter, which reported energy sales of 485 GWh. The increase was partially offset by decreased production in Belize due to lower rainfall and decreased production in Upstate New York and Ontario due to the sale of generation assets, as discussed above for the quarter, lower rainfall, and generating units taken out of service for repairs.

Revenue

The increase in revenue for the quarter and year to date was driven by the Waneta Expansion, which recognized revenue of $18 million and $49 million, respectively, and favourable foreign exchange associated with the translation of US dollar-denominated revenue of approximately $2 million and $3 million, respectively. Increased production in Belize also contributed to the increase for the quarter. The increase in revenue year to date was partially offset by decreased production in Belize, Upstate New York and Ontario.

Earnings

The increase in earnings for the quarter was due to earnings contribution of $5 million from the Waneta Expansion, which represents the Corporation’s 51% controlling ownership interest, the recognition of an after-tax gain of approximately $5 million on the sale of generation assets in Ontario in July 2015, increased production in Belize, and approximately $2 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings.

The increase in earnings year to date was driven by the recognition of after-tax gains of approximately $27 million (US$22 million) and $5 million, net of expenses and foreign exchange impacts, on the sale of generation assets in Upstate New York in June 2015 and Ontario in July 2015, respectively, and earnings contribution of $17 million from the Waneta Expansion. Favourable foreign exchange associated with the translation of US dollar-denominated earnings of approximately $2 million and lower business development costs were partially offset by decreased production in Belize, Upstate New York and Ontario.

NON-REGULATED - NON-UTILITY [(1)]

Financial Highlights (Unaudited) Periods Ended September 30 ($ millions)	Quarter 2015	 2014	 Variance	Year-to-Date 2015	 2014	 Variance
Revenue	**47**	68	(21)	**165**	187	(22)
Earnings	**11**	9	2	**113**	21	92

(1) Comprised of Fortis Properties and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate and hotel assets in June 2015 and October 2015, respectively. For further information, refer to the "Significant Items" section of this MD&A. Griffith was sold in March 2014. As such, the results of operations of Griffith have been presented as discontinued operations on the consolidated statements of earnings and, accordingly, revenue excludes amounts associated with Griffith. Earnings, however, reflect the financial results of Griffith to March 2014.

Revenue

The decrease in revenue at Fortis Properties for the quarter and year to date was primarily due to the sale of commercial real estate assets in June 2015.

Earnings

Earnings for the quarter reflect a $5 million positive adjustment, largely related to a deferred income tax recovery, associated with the sale of hotel assets, compared to an after-tax loss of approximately $8 million year to date. An after-tax gain of approximately $109 million, net of expenses, on the sale of Fortis Properties' commercial real estate assets was recognized in the second quarter of 2015. For further information, refer to the "Significant Items" section of this MD&A.

Excluding the impacts of the above-noted sales transactions, Fortis Properties contributed earnings of $6 million and $12 million for the quarter and year to date, respectively, compared to $9 million and $16 million, respectively, for the same periods last year. The decrease in earnings was primarily due to the sale of commercial real estate assets in June 2015, partially offset by lower depreciation associated with the hotel assets. Earnings for the first quarter of 2014 include $5 million associated with Griffith from normal operations to the date of sale in March 2014.

CORPORATE AND OTHER [(1)]

Financial Highlights (Unaudited) Periods Ended September 30 ($ millions)	Quarter 2015	 2014	 Variance	Year-to-Date 2015	 2014	 Variance
Revenue	**8**	9	(1)	**22**	24	(2)
Operating Expenses	**8**	16	(8)	**25**	30	(5)
Depreciation and Amortization	**-**	1	(1)	**1**	2	(1)
Other Income (Expenses), Net	**(4)**	(48)	44	**4**	(49)	53
Finance Charges	**25**	57	(32)	**70**	125	(55)
Income Tax Recovery	**(13)**	(40)	27	**(32)**	(64)	32
	(16)	(73)	57	**(38)**	(118)	80
Preference Share Dividends	**19**	15	4	**58**	42	16
Net Corporate and Other Expenses	**(35)**	(88)	53	**(96)**	(160)	64

(1) Includes Fortis net Corporate expenses; non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. and UNS Energy Corporation; and the financial results of FHI's wholly owned subsidiary FortisBC Alternative Energy Services Inc.

Net Corporate and Other expenses were impacted by the following items:

(i) A foreign exchange gain of approximately $5 million and $13 million for the third quarter and year-to-date 2015, respectively, compared to approximately $5 million for each of the third quarter and year-to-date 2014, associated with the Corporation's previous US-dollar denominated long-term other asset that represented the book value of the Corporation's expropriated investment in Belize Electricity, which was included in other income;
(ii) A loss of approximately $9 million recognized in the third quarter of 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses;
(iii) Finance charges of $33 million ($23 million after tax) and $67 million ($47 million after tax) for the third quarter and year-to-date 2014, respectively, associated with the convertible debentures issued in January 2014 to finance a portion of the acquisition of UNS Energy;
(iv) Other expenses of approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, associated with customer benefits offered by the Corporation to close the acquisition of UNS Energy, recognized in the third quarter of 2014; and
(v) Other expenses of $20 million ($15 million after tax) and $24 million ($18 million after tax) for the third quarter and year-to-date 2014, respectively, related to the acquisition of UNS Energy.

Excluding the above-noted items, net Corporate and Other expenses were $31 million and $100 million for the quarter and year to date, respectively, compared to $35 million and $80 million, respectively, for the same periods last year. The variance explanations below exclude the above-noted items.

The $4 million decrease in net Corporate and Other expenses for the quarter was primarily due to lower operating expenses, partially offset by higher preference share dividends associated with preference shares issued to finance a portion of the acquisition of UNS Energy. Retirement expenses of approximately $9 million ($8 million after tax) were recognized in the third quarter of 2014. Finance charges were comparable quarter over quarter. The impacts of no longer capitalizing interest upon completion of the Waneta Expansion, new long-term debt associated with the acquisition of UNS Energy, and unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense were largely offset by interest on the Corporation's acquisition credit facility in the third quarter of 2014, which was used to initially finance a portion of the acquisition of UNS Energy.

The $20 million increase in net Corporate and Other expenses year to date was primarily due to higher preference share dividends and finance charges, largely as a result of the acquisition of UNS Energy. Finance charges were also impacted by no longer capitalizing interest upon completion of the Waneta Expansion and unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense. The increases were partially offset by a higher income tax recovery and lower operating expenses. Retirement expenses of approximately $13 million ($11 million after tax) were recognized year-to-date 2014 compared to approximately $2 million ($1 million after tax) recognized year-to-date 2015. Additionally, a $3 million ($2 million after tax) corporate donation was recognized in the second quarter of 2015.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

The nature of regulation associated with each of the Corporation's regulated electric and gas utilities is generally consistent with that disclosed in the 2014 Annual MD&A. The following summarizes the significant regulatory decisions and applications for the Corporation's regulated utilities year-to-date 2015.

UNS Energy
In November 2015 TEP, UNS Energy's largest utility, filed a GRA with the ACC requesting new retail rates to be effective January 1, 2017, using June 30, 2015 as a historical test year. The key provisions of the rate request include: (i) a base retail rate increase of US$110 million, or 12.0%, compared with adjusted test year revenue; (ii) a 7.34% return on original cost rate base of US$2.1 billion, which includes approximately US$73 million of post-test year adjustments for utility capital assets that are expected to be in service by December 31, 2016; (iii) a common equity component of capital structure of approximately 50%; and (iv) rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from approximately 43.5% to approximately 50%. In May 2015 UNS Electric filed a GRA requesting new retail rates to be effective May 1, 2016, using December 31, 2014 as a historical test year. The nature of UNS Electric's GRA was similar to that of TEP.

Central Hudson
In June 2015 the PSC issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US$225 million in energy infrastructure during the two-year delivery rate freeze period ending June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Rate Order includes capital investments of approximately US$490 million during the three-year period targeted at making the electric and gas systems stronger.

The approved Rate Order includes full cost recovery of electric and natural gas commodity costs and continuation of certain mechanisms, including revenue decoupling and earnings sharing mechanisms. In the approved earnings sharing mechanism, the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. In addition, the Rate Order includes a major storm reserve for electric operations and provides for continuation of recovery of various operating expenses, including environmental site investigation and remediation costs. To the extent that Central Hudson receives gas delivery revenue associated with a new contract in late 2014, effective July 1, 2015, associated revenue is being used to mitigate future gas customer rate increases.

FortisBC Energy and FortisBC Electric
On December 31, 2014, FEI, FEVI and FEWI were amalgamated, as approved by the British Columbia Utilities Commission ("BCUC") in February 2014, and FEI is the resulting Company. Prior to the amalgamation, the allowed ROEs for FEVI and FEWI were 9.25% and 9.50%, respectively, on a common equity component of capital structure of 41.5%. Effective January 1, 2015, the allowed ROE and common equity component of capital structure reverted to those of FEI, which are 8.75% and 38.5%, respectively.

In May 2015 and June 2015, the BCUC issued its decisions on FEI and FortisBC Electric's 2015 rates in compliance with the PBR decisions issued in September 2014. The decisions approved 2015 midyear rate base of approximately $3,661 million and $1,249 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2015 of 0.7% and 4.2% over 2014 rates, respectively. For FortisBC Electric, this decision results in the Company applying a 3.5% rate increase from January 1, 2015 to July 31, 2015, and a 5.1% rate increase effective August 1, 2015, both as compared to 2014 rates.

In September 2015 FEI and FortisBC Electric filed applications for approval of 2016 rates under the PBR plan. The 2016 applications include forecast midyear rate base of approximately $3,691 million and $1,287 million for FEI and FortisBC Electric, respectively, and request approval of customer rate increases for 2016 of 2.22% and 1.98%, respectively. In October 2015 the Companies filed evidentiary updates to the applications, which updated the 2016 customer rate increases to 2.74% for FEI and 3.12% for FortisBC Electric.

In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. As FEI is the benchmark utility, the review of the application could also have an impact on FortisBC Electric.

FortisAlberta

Generic Cost of Capital Proceedings

In March 2015 the Alberta Utilities Commission ("AUC") issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it will not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE of 8.75% and common equity component of capital structure of 41%, as set in a previous GCOC decision.

In April 2015 the AUC initiated a GCOC Proceeding to set the allowed ROE and capital structure for 2016 and 2017. While the AUC approved a request by utilities in Alberta to negotiate matters at issue in the GCOC Proceeding for 2016, a negotiated settlement was not reached. Therefore, the 2016 and 2017 GCOC Proceeding will commence in the first quarter of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures.

In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the criteria established in the original PBR decision and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital used in the accounting test is to be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding. Substantially all of FortisAlberta's capital programs were approved as filed.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million and $29 million in 2013 and 2014, respectively, and expects to collect $62 million in 2015, related to capital tracker expenditures.

In May 2015 FortisAlberta filed an application with the AUC seeking: (i) capital tracker revenue for 2016 of $72 million and 2017 of $90 million, respectively; (ii) a reduction of $7 million to reflect actual capital expenditures; and (iii) approval of additional revenue of $3 million related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015, with a decision from the regulator expected in the first quarter of 2016.

FortisAlberta expects to recognize capital tracker revenue of approximately $59 million in 2015, of which $9 million is related to 2013 and 2014 capital tracker expenditures and is not yet collected from customers. The capital tracker revenue for 2015 of approximately $50 million incorporates an updated forecast for related capital expenditures as compared to the approved forecast reflected in current rates. This is expected to result in a deferral of approximately $12 million of 2015 capital tracker revenue as a regulatory liability. For the nine months ended September 30, 2015, FortisAlberta recognized capital tracker revenue of approximately $36 million related to 2015 capital tracker expenditures and deferred $9 million of revenue as a regulatory liability.

2016 Annual Rates Application

In September 2015 FortisAlberta filed its 2016 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2016, include an increase of approximately 6.2% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of $72 million, which is 100% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed for in the capital tracker applications, as discussed previously; and (iii) $17 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed for in the capital tracker compliance filing related to the 2015 capital tracker decision. A decision on this filing is expected in the fourth quarter of 2015.

Utility Asset Disposition Matters

In previous decisions, the AUC made statements regarding cost responsibility for stranded assets and gains or losses related to extraordinary retirement of utility assets, which FortisAlberta and other Alberta 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 also conflicted with the *Electric Utilities Act* (Alberta). As a result, the utilities in Alberta had filed leave to appeal motions with the Court of Appeal of Alberta.

In September 2015 the Court of Appeal of Alberta issued a decision that dismissed the appeals of the utilities. The basis for the decision was that the AUC should be accorded deference for its conclusions in utility asset disposition matters. The decision by the Court of Appeal of Alberta has no immediate impact on FortisAlberta's financial position. However, the Company is exposed to the risk that the remaining unrecovered costs of utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers. FortisAlberta is assessing its option to file a leave to appeal motion with the Supreme Court of Canada.

Eastern Canadian Electric Utilities

In October 2015 Newfoundland Power filed a 2016/2017 GRA with the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") to set customer rates effective July 1, 2016. The Company is proposing an overall average increase in electricity rates of 3.1%. This proposed increase results from a full review of Newfoundland Power's costs, including cost of capital. The application is currently under review by the PUB and a hearing is expected in the first half of 2016.

In October 2015 Maritime Electric filed a GRA with the Island Regulatory and Appeals Commission to set customer rates effective March 1, 2016, on expiry of the *Prince Edward Island Energy Accord*. The Company is proposing an overall average increase in electricity rates of 2.5%.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's regulated utilities.

Regulated Utility	Application / Proceeding	Filing Date	Expected Decision
TEP	GRA for 2017	Fourth quarter of 2015	To be determined
Central Hudson	Reforming the Energy Vision	Not applicable	To be determined
FEI	2016 Cost of Capital Application	Fourth quarter of 2015	To be determined
FortisAlberta	2016 Annual Rates Application	Third quarter of 2015	Fourth quarter of 2015
	2016/2017 Capital Tracker Application	Second quarter of 2015	First quarter of 2016
	2016/2017 GCOC Proceeding	Not applicable	To be determined
Newfoundland Power	GRA for 2016/2017	Fourth quarter of 2015	To be determined
Maritime Electric	GRA for 2016	Fourth quarter of 2015	To be determined

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between September 30, 2015 and December 31, 2014.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between September 30, 2015 and December 31, 2014

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Cash and cash equivalents	117	The increase was mainly due to an increase in cash at the Corporation, due to proceeds received on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, an increase in cash at the Waneta Expansion and the impact of foreign exchange on the translation of US dollar-denominated cash.
Accounts receivable and other current assets	(104)	The decrease was primarily due to the impact of a seasonal decrease in sales at FortisBC Energy and Newfoundland Power, partially offset by a seasonal increase in sales at UNS Energy and the impact of foreign exchange on US dollar-denominated accounts receivable.
Assets held for sale	390	The increase was primarily due to the sale of Fortis Properties' hotel assets in October 2015, which were reclassified from non-utility capital assets.
Utility capital assets	1,781	The increase was primarily due to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation.
Non-utility capital assets	(664)	The decrease was due to the sale of Fortis Properties' commercial real estate assets in June 2015 and hotel assets in October 2015, which were reclassified to assets held for sale.
Goodwill	343	The increase was due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Long-term debt (including current portion)	842	The increase was primarily due the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US-dollar denominated debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities.
Capital lease and finance obligations (including current portion)	(188)	The decrease was mainly due to the purchase of an additional ownership interest in the Springerville Unit 1 generating facility and the Springerville coal handling facilities at UNS Energy following the expiry of lease arrangements.
Deferred income tax liabilities – current and long-term	234	The increase was mainly due to the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities, tax timing differences mainly related to capital expenditures at the regulated utilities, and an increase in the provincial statutory tax rate at FortisAlberta.
Shareholders' equity (before non-controlling interests)	943	The increase primarily related to: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the nine months ended September 30, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

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, 2015, as compared to the same periods in 2014, 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)	**2015**	2014	Variance	**2015**	2014	Variance
Cash, Beginning of Period	**797**	612	185	**230**	72	158
Cash Provided by (Used in):						
Operating Activities	**358**	62	296	**1,276**	648	628
Investing Activities	**(446)**	(2,972)	2,526	**(1,134)**	(3,370)	2,236
Financing Activities	**(388)**	2,748	(3,136)	**(66)**	3,104	(3,170)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**24**	8	16	**41**	4	37
Change in Cash Associated with Assets Held for Sale	**2**	-	2	**-**	-	-
Cash, End of Period	**347**	458	(111)	**347**	458	(111)

Operating Activities: Cash flow from operating activities was $296 million higher quarter over quarter. The increase was primarily due to higher cash earnings, largely due to the acquisition of UNS Energy in August 2014. Favourable changes in regulatory deferrals at FortisBC Energy and favourable changes in working capital, mainly associated with accounts payable at UNS Energy, also contributed to the increase for the quarter.

Cash flow from operating activities was $628 million higher year to date compared to the same period last year. The increase was primarily due to higher cash earnings, largely due to the acquisition of UNS Energy, as discussed above for the quarter. Favourable changes in working capital at UNS Energy, FortisBC Energy and Central Hudson, mainly associated with accounts payable, inventory and current regulatory deferrals, respectively, also contributed to the year-to-date increase in cash flow from operating activities. The increases were partially offset by unfavourable changes in working capital at FortisAlberta, mainly associated with current regulatory deferrals and accounts receivable.

Investing Activities: Cash used in investing activities was $2,526 million lower quarter over quarter. The decrease was primarily due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of $2,745 million. The decrease was partially offset by capital expenditures at UNS Energy and higher capital spending at most of the Corporation's regulated utilities.

Cash used in investing activities was $2,236 million lower year to date compared to the same period last year. The decrease was primarily due to the acquisition of UNS Energy in August 2014, as discussed above for the quarter. Also contributing to the decrease were proceeds received from the sale of Fortis Properties' commercial real estate assets and generation assets in Upstate New York in June 2015 for approximately $430 million and $77 million (US$63 million), respectively, compared to proceeds of approximately $105 million (US$95 million) on the sale of Griffith in March 2014. The decrease was partially offset by capital expenditures at UNS Energy and higher capital spending at most of the Corporation's regulated utilities.

Financing Activities: Cash provided by financing activities was $3,136 million lower quarter over quarter. The decrease was primarily due to financing associated with the acquisition of UNS Energy in August 2014, including borrowings under the Corporation's acquisition credit facilities and the issuance of preference shares. Lower proceeds from the issuance of long-term debt, higher repayments of long-term debt and higher net repayments of committed credit facility borrowings were partially offset by higher short-term borrowings at FortisBC Energy.

Cash provided by financing activities was $3,170 million lower year to date compared to the same period last year. The decrease was primarily due to financing associated with the acquisition of UNS Energy, as discussed above for the quarter, combined with $599 million, or $561 million net of issue costs, from the first installment of convertible debentures issued in January 2014 also to finance a portion of the acquisition of UNS Energy. Higher repayments of long-term debt and higher net repayments of committed credit facility borrowings also contributed the year-to-date decrease in cash provided by financing activities, which was partially offset by higher proceeds from the issuance of long-term debt.

Proceeds from long-term debt, net of issue costs, 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.

Proceeds from Long-Term Debt, Net of Issue Costs (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2015**	2014	Variance	**2015**	2014	Variance
UNS Energy [(1)]	**163**	-	163	**594**	-	594
Central Hudson [(2)]	**-**	-	-	**25**	33	(8)
FortisBC Energy [(3)]	**-**	-	-	**150**	-	150
FortisAlberta [(4)]	**149**	274	(125)	**149**	274	(125)
Newfoundland Power [(5)]	**75**	-	75	**75**	-	75
Corporate [(6)]	**-**	312	(312)	**-**	539	(539)
Other [(7)]	**-**	-	-	**12**	-	12
Total	**387**	586	(199)	**1,005**	846	159

(1) In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used to repay short-term borrowings. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured debentures and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt and for general corporate purposes.

(2) In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for other general corporate purposes.

(3) In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

(4) In September 2015 FortisAlberta issued 30-year $150 million 4.27% unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes. In September 2014 FortisAlberta issued $275 million senior unsecured debentures in a dual tranche of 10-year $150 million and 30-year $125 million at 3.30% and 4.11%, respectively. The net proceeds were used to repay maturing long-term debt in October 2014, to finance capital expenditures and for general corporate purposes.

(5) In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(6) In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 years to 30 years and coupon rates ranging from 2.92% to 4.88%. The notes have a weighted-average term to maturity of approximately 9 years and a weighted-average coupon rate of 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 years to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted-average term to maturity is approximately 12 years and the weighted-average coupon rate is 4.11%. Net proceeds were used to refinance existing indebtedness, including the US$150 million 5.74% senior unsecured notes of Fortis that matured in October 2014 and $125 million 5.56% unsecured debentures of a subsidiary that matured in September 2014, and for general corporate purposes.

(7) In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2015**	2014	Variance	**2015**	2014	Variance
UNS Energy	**(276)**	-	(276)	**(449)**	-	(449)
Central Hudson	**-**	-	-	**-**	(16)	16
FortisBC Energy	**(75)**	(1)	(74)	**(89)**	(4)	(85)
Newfoundland Power	**-**	(29)	29	**-**	(29)	29
Caribbean Utilities	**-**	-	-	**(13)**	(15)	2
Corporate	**-**	(125)	125	**-**	(125)	125
Other	**(2)**	(2)	-	**(38)**	(12)	(26)
Total	**(353)**	(157)	(196)	**(589)**	(201)	(388)

Net (Repayments) Borrowings Under Committed Credit Facilities (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2015**	2014	Variance	**2015**	2014	Variance
UNS Energy	**(19)**	-	(19)	**(141)**	-	(141)
FortisAlberta	**(105)**	-	(105)	**(23)**	(20)	(3)
FortisBC Electric	**-**	36	(36)	**-**	(43)	43
Newfoundland Power	**(92)**	33	(125)	**(65)**	33	(98)
Corporate [(1)]	**(370)**	257	(627)	**(95)**	83	(178)
Total	**(586)**	326	(912)	**(324)**	53	(377)

(1) Repayments under the Corporation's credit facility in the third quarter of 2015 were made using net proceeds from the sale of commercial real estate assets in June 2015. Year-to-date 2015, net repayments were partially offset by borrowings to finance equity injections into UNS Energy and FEI, and for other general corporate purposes.

Borrowings under credit facilities by the utilities are primarily in support of their respective 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.

Common share dividends paid in the third quarter of 2015 were $56 million, net of $38 million of dividends reinvested, compared to $51 million, net of $18 million of dividends reinvested, paid in the same quarter of 2014. Common share dividends paid year-to-date 2015 were $171 million, net of $112 million in dividends reinvested, compared to $146 million, net of $60 million in dividends reinvested, paid year-to-date 2014. The dividend paid per common share for each of the first, second and third quarters of 2015 was $0.34 compared to $0.32 for each of the same quarters of 2014. The weighted average number of common shares outstanding for the third quarter and year-to-date 2015 was 279.1 million and 277.9 million, respectively, compared to 215.6 million and 214.6 million for the same periods in 2014.

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, 2015, are outlined in the following table. A detailed description of the nature of the obligations is provided in the 2014 Annual MD&A and below, where applicable.

Contractual Obligations (Unaudited) As at September 30, 2015 *($ 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	**11,343**	543	174	87	384	569	9,586
Interest obligations on long-term debt	**9,487**	530	505	501	491	482	6,978
Capital lease and finance obligations	**2,450**	69	71	63	91	86	2,070
Renewable power purchase obligations (1)	**1,550**	89	89	89	89	88	1,106
Power purchase obligations (2) (3)	**1,529**	264	222	195	120	50	678
Long-term contracts - UNS Energy	**1,037**	145	139	109	99	83	462
Gas purchase contract obligations	**923**	320	130	117	76	66	214
Capital cost	**493**	19	19	19	19	19	398
Operating lease obligations	**177**	13	11	11	11	13	118
Renewable energy credit purchase agreements	**159**	12	12	12	12	12	99
Purchase of Springerville common facilities	**142**	-	-	51	-	-	91
Defined benefit pension funding contributions	**129**	34	17	9	9	10	50
Waneta Partnership promissory note	**72**	-	-	-	-	72	-
Joint-use asset and shared service agreements	**54**	3	3	3	3	3	39
Other	**81**	12	10	13	3	-	43
Total	**29,626**	2,053	1,402	1,279	1,407	1,553	21,932

(1) UNS Energy is party to renewable power purchase agreements totalling approximately US$1,162 million as at September 30, 2015, which require UNS Energy to purchase 100% of certain renewable energy generation facilities that have achieved commercial operation. In September 2015 one of the facilities achieved commercial operation, increasing estimated future payments of renewable power purchase contracts by US$315 million as at September 30, 2015.

(2) In March 2015 Maritime Electric extended its power purchase agreement with New Brunswick Power from March 2016 to February 2019, increasing the total commitment under this agreement by approximately $172 million as at September 30, 2015.

(3) FortisBC Energy has entered into an Electricity Supply Agreement with BC Hydro for the purchase of electrical service to the Tilbury Expansion Project, with obligations totalling approximately $548 million as at September 30, 2015.

Other contractual obligations, which are not reflected in the above table, did not materially change from those disclosed in the 2014 Annual MD&A.

For a discussion of the nature and amount of the Corporation's consolidated capital expenditure program 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 electric and gas utilities 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 ensure continued access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 35% common equity, 65% debt and preferred equity, 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, 2015		December 31, 2014	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**11,908**	**55.3**	11,304	56.5
Preference shares	**1,820**	**8.4**	1,820	9.1
Common shareholders' equity	**7,814**	**36.3**	6,871	34.4
Total [(2)]	**21,542**	**100.0**	19,995	100.0

(1) Includes long-term debt, capital lease and finance obligations, including current portion, and short-term borrowings, net of cash

(2) Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at September 30, 2015 was 54.2% debt, 8.6% preference shares and 37.2% common shareholders' equity (December 31, 2014 - 55.0% debt, 9.4% preference shares and 35.6% common shareholders' equity).

The improvement in the capital structure was due to an increase in common shareholder's equity as a result of: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the nine months ended September 30, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans. The capital structure was also impacted by an increase in total debt, mainly due to the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US-dollar denominated debt, partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities.

CREDIT RATINGS

The Corporation's credit ratings are as follows:

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

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In April 2015 S&P confirmed the Corporation's credit rating with a Stable outlook.

CAPITAL EXPENDITURE PROGRAM

A breakdown of the $1,683 million in gross consolidated capital expenditures by segment year-to-date 2015 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year-to-Date September 30, 2015
($ millions)

Regulated Utilities								**Non-Regulated**		
UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Electric Caribbean	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility**	**Total**
552	123	364	306	83	115	95	**1,638**	**31**	**14**	**1,683**

(1) Relates to cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the 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 2015 are forecast to be approximately $2.2 billion. There have been no material changes in the overall expected level, nature and timing of the Corporation's significant capital projects from those that were disclosed in the 2014 Annual MD&A.

Construction of the $900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts.

Construction of FEI's Tilbury liquefied natural gas ("LNG") facility expansion ("Tilbury 1A") in Delta, British Columbia is ongoing. Key construction activities during the third quarter included continued construction on the LNG storage tank, the liquefaction process area foundations and structural steel, and the power substations. Tilbury 1A will be included in regulated rate base and is estimated to cost approximately $440 million, including an equity component of AFUDC. It will include a second LNG tank and a new liquefier, both expected to be in service by the end of 2016. Approximately $268 million has been invested in Tilbury 1A to the end of the third quarter.

In January 2015, upon expiration of the Springerville Unit 1 lease, UNS Energy closed the purchase of an additional ownership interest in the unit for US$46 million. UNS Energy's ownership interests in Springerville Unit 1 now total 49.5%. Additionally, upon expiration of the Springerville Coal Handling Facilities lease in April 2015, UNS Energy purchased an additional ownership interest in the previously leased coal-handling assets for US$72 million.

The Pinal Transmission Project at UNS Energy is the construction of a 500-kilovolt transmission line in Pinal County that will increase the Company's import capacity from the Palo Verde trading hub. Key construction activities during the third quarter include completion of the installation of the conductor wires, optical ground wires and static wires from the substation to all of the structures. Construction of the transmission line was completed in October 2015 and the lines are expected to be energized in November 2015 once the expansion of the Tortolia Substation is complete. The total cost of the project is expected to be US$79 million, of which approximately US$72 million has been invested to the end of the third quarter.

Caribbean Utilities was the successful bidder for new generation capacity and entered into a design-build contract agreement to cover the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. Key construction activities during the third quarter were completion of the engine and steam turbine foundations as well the fourth borehole. Continued construction on underground utilities work, steel structures and the service tank farm occurred during the third quarter. The project cost is estimated at US$85 million and the plant is expected to be commissioned by June 2016. Approximately US$40 million has been invested to date.

FortisBC is pursuing additional LNG infrastructure investment opportunities, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC. These additional investment opportunities, discussed in further detail below, are not included in the Corporation's capital expenditure forecast.

The pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. The Woodfibre LNG plant has passed the British Columbia Environmental Assessment Office review and the Squamish First Nation approved an environmental certificate for the project in October 2015. These approvals are significant milestones; however, the project is pending a Federal Environmental Assessment. In addition, FortisBC Energy's pipeline expansion, at an estimated total project cost of $600 million, is also subject to various environmental approvals. A final investment decision by Woodfibre LNG is expected in 2016.

The further expansion of Tilbury is conditional upon having long-term energy supply contracts in place for 70% of the additional liquefaction capacity, on average, for the first 15 years of operation. FortisBC has a conditional contract with Hawaiian Electric Company that would meet this requirement, subject to the regulatory approval process in Hawaii. The Corporation continues to have discussions with Hawaiian Electric Company, which is expected to be the primary offtaker, regarding the viability and scope of the project. Any resulting agreement would be subject to the approval of the Hawaii Public Utilities Commission.

Over the five-year period through 2020, gross consolidated capital expenditures are expected to reach almost $9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 39% at U.S. Regulated Electric & Gas Utilities; 38% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 18% at Canadian Regulated Gas Utility; 4% at Caribbean Regulated Electric Utilities; and the remaining 1% 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: 49% for sustaining capital expenditures, 35% to meet customer growth, and 16% 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. The subsidiaries expect to be able to source the cash required to fund their 2015 capital expenditure programs.

In April 2015 FortisBC Energy filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $1 billion during the 25-month life of the shelf prospectus. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures under the base shelf prospectus. The net proceeds were used to repay short-term borrowings.

In June 2015 Fortis injected US$180 million of equity into TEP. Proceeds were used to repay credit facility borrowings in June 2015 and the balance was used to redeem bonds in August 2015 and provide additional liquidity to TEP. This equity injection fulfilled one of the commitments made by Fortis in order to receive regulatory approval for the acquisition of UNS Energy, and increased TEP's equity thickness to almost 50%, which is comparable with other regulated utilities in Arizona.

In May 2015 Caribbean Utilities completed a rights offering in which it raised gross proceeds of US$32 million through the issue of 2.9 million common shares. Fortis invested US$23 million in approximately 2.2 million common shares of Caribbean Utilities. The net proceeds from the rights offering were used by Caribbean Utilities to finance capital expenditures.

In October 2015 FortisAlberta filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $500 million during the 25-month life of the shelf prospectus.

As at September 30, 2015, management expects consolidated fixed-term debt maturities and repayments to average approximately $200 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

Fortis and its subsidiaries were compliant with debt covenants as at September 30, 2015 and are expected to remain compliant throughout 2015.

CREDIT FACILITIES

As at September 30, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.3 billion, of which approximately $2.0 billion was unused, including $273 million unused under the Corporation's 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 $3.1 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

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, 2015**	December 31, 2014
Total credit facilities [(1)]	2,013	13	1,297	**3,323**	3,854
Credit facilities utilized:					
Short-term borrowings	(397)	-	-	**(397)**	(330)
Long-term debt [(2)]	-	-	(832)	**(832)**	(1,096)
Letters of credit outstanding	(71)	-	(34)	**(105)**	(192)
Credit facilities unused	1,545	13	431	**1,989**	2,236

(1) Total credit facilities exclude a $300 million increase to the Corporation's committed corporate credit facility in March 2015, as discussed below.

(2) As at September 30, 2015, credit facility borrowings classified as long-term debt included $230 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 - $257 million).

As at September 30, 2015 and December 31, 2014, 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.

The significant changes in available credit facilities from that disclosed in the Corporation's 2014 Annual MD&A are as follows.

In March 2015 the Corporation amended its $1 billion corporate committed credit facility, resulting in the ability to increase the facility to $1.3 billion and an extension of the maturity date to July 2020 from July 2018. As at September 30, 2015, the Corporation has not yet exercised its option for the additional $300 million.

In March 2015 TEP repaid its US$130 million non-revolving term loan commitment using net proceeds from the issuance of long-term debt. In June 2015 TEP terminated the associated credit agreement, which also included US$70 million in unsecured committed revolving credit facilities.

In April 2015 FortisBC Electric amended its $150 million unsecured committed revolving credit facility to now mature in May 2018.

In June 2015 FortisOntario amended its $30 million unsecured committed revolving credit facility to now mature in June 2016.

In July 2015 FortisAlberta renegotiated and amended its $250 million unsecured committed revolving credit facility, extending the maturity date to August 2020 from August 2019.

In July 2015 CH Energy Group amended its US$100 million committed credit facility, resulting in a decrease in the facility to US$50 million and an extension of the maturity date to July 2020 from October 2015. In October 2015 Central Hudson entered into a US$200 million unsecured committed revolving credit facility maturing in October 2020, replacing its previous US$150 million credit facility.

In July 2015 the Corporation repaid its $273 million medium-term bridge facility using net proceeds from the sale of commercial real estate assets.

In August 2015 Fortis Turks and Caicos amended its US$26 million unsecured demand credit facilities to now mature in September 2016.

In August 2015 FortisBC Energy amended its $500 million credit facility, resulting in an increase in the facility to $700 million and an extension of the maturity date to August 2018 from August 2016, and cancelled its $200 million credit facility due to mature in December 2015.

In September 2015 TEP terminated its US$82 million letter of credit facility. In October 2015 TEP, UNS Electric and UNS Gas entered into unsecured committed revolving credit facilities totalling US$350 million maturing in October 2020, replacing their previous US$300 million credit facilities. In addition, UNS Energy Corporation entered into a US$150 million unsecured committed revolving credit facility maturing in October 2020, replacing its previous US$125 million facility. The new credit facility agreements allow for two one-year extensions.

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, 2015		December 31, 2014	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**55**	**58**	53	56
Long-term debt, including current portion	**11,343**	**12,721**	10,501	12,237

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) 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 following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. The fair values reflect point-in-time estimates based on current and relevant market information as at the balance sheet dates. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value (Unaudited)		**As at**	
($ millions)	**Fair value hierarchy**	**September 30, 2015**	December 31, 2014
Assets			
Energy contracts subject to regulatory deferral (1) (2) (3)	Levels 2/3	**2**	3
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**3**	1
Available-for-sale investment (4) (5)	Level 1	**34**	-
Assets held for sale	Level 2	**362**	-
Other investments (4)	Level 1	**12**	5
Total gross assets		**413**	9
Less: Counterparty netting not offset on the balance sheet (6)		**(2)**	(3)
Total net assets		**411**	6
Liabilities			
Energy contracts subject to regulatory deferral (1) (2) (7)	Levels 1/2/3	**65**	72
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**-**	1
Energy contracts - cash flow hedges (2) (8)	Level 3	**-**	1
Interest rate swaps - cash flow hedges (8)	Level 2	**5**	5
Total gross liabilities		**70**	79
Less: Counterparty netting not offset on the balance sheet (6)		**(2)**	(3)
Total net liabilities		**68**	76

(1) The fair value of the Corporation's energy contracts are recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

(3) Includes less than $1 million - level 2 and $1 million - level 3 (2014 - $3 million - level 3)

(4) Included in long-term other assets on the consolidated balance sheet.

(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

(7) Includes $1 million – level 1, $44 million - level 2 and $20 million - level 3 (2014 - $2 million - level 1, $35 million - level 2 and $35 million - level 3)

(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation is required to record all derivative instruments at fair value, except for those that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments 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.

Energy Contracts Subject to Regulatory Deferral
UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts are estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums 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 derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at September 30, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at September 30, 2015, unrealized losses of $63 million (December 31, 2014 - $69 million) were recognized in current regulatory assets and no unrealized gains were recognized in regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral
In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges
UNS Energy holds interest rate swaps, expiring through 2020, to mitigate its exposure to volatility in variable interest rates on debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

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

Volume of Derivative Activity

As at September 30, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2015	2016	2017	2018	2019	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2017	6	295	713	219	-	-	-
Electricity power purchase contracts *(GWh)*	2017	23	271	780	145	-	-	-
Gas swap and option contracts *(PJ)*	2018	176	11	29	8	1	-	-
Gas purchase contract premiums *(PJ)*	2024	94	39	87	40	37	22	87
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	663	1,310	-	-	-	-

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $105 million as at September 30, 2015 (December 31, 2014 - $192 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 2015, the business risks of the Corporation were generally consistent with those disclosed in the Corporation's 2014 Annual MD&A, including certain risks, as disclosed below, and an update to those risks, where applicable.

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

Expropriation of Shares in Belize Electricity: As a result of the settlement with the GOB regarding the GOB's expropriation of the Corporation's 70% interest in Belize Electricity in June 2011, the risks associated with this expropriation are no longer applicable. For further information, refer to the "Significant Items" section of this MD&A.

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion on managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements that could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third-party owners with respect to the existing facility support agreement for Springerville Unit 1. This dispute has resulted in the refusal of third-party owners to pay their pro rata share of such Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Environmental Risks: In August 2015 the United States Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP") limiting carbon emissions from existing and new fossil fuelled power plants. The CPP establishes state-level carbon emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that receive an extension must submit a final completed plan to the EPA by September 2018. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, including the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP plans to comment on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo. TEP cannot predict the ultimate outcome of these matters. TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule.

Capital Project Budget Overrun, Completion and Financing Risk in the Corporation's Non-Regulated Business: As a result of the completion of the Waneta Expansion on April 1, 2015, ahead of schedule and on budget, the risks associated with this capital project are no longer applicable.

Capital Resources and Liquidity Risk - Credit Ratings: In February 2015 Moody's Investor Service ("Moody's") upgraded the debt credit ratings of UNS Energy to 'Baa1' from 'Baa2' and TEP, UNS Electric and UNS Gas to 'A3' from 'Baa1'. In July 2015 Fitch Ratings downgraded Central Hudson's debt credit rating to 'A-' from 'A' and changed the rating outlook to Stable from Negative. Central Hudson's debt continues to be rated 'A' by S&P and 'A2' by Moody's, both with Stable outlooks.

Defined Benefit Pension and Other Post-Employment Benefit Plan Assets: As at September 30, 2015, the fair value of the Corporation's consolidated defined benefit pension and other post-employment benefit plan assets was $2,560 million, up $190 million or 8% from $2,370 million as at December 31, 2014.

Labour Relations: The collective agreement between FortisBC Energy and Canadian Office and Professional Employees Union, representing employees in specified occupations in the areas of administration and operations support expired on March 31, 2015 and was renewed in the second quarter for a three-year term which expires on March 31, 2018.

The two collective agreements between Newfoundland Power and International Brotherhood of Electrical Workers ("IBEW") expired on September 30, 2014. The Company and IBEW reached tentative agreements in December 2014. One agreement was ratified in March 2015 and the second was ratified in June 2015. The contracts expire in September 2017.

CHANGES IN ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared following the same accounting policies and methods as those used to prepare the Corporation's 2014 annual audited consolidated financial statements, except as described below.

Available-for-Sale Assets
The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
Effective January 1, 2015, the Corporation adopted amendments to Accounting Standards Codification ("ASC"), Topics 205 and 360, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity,* as outlined in Accounting Standards Update ("ASU") No. 2014-08. The amendments were applied prospectively and, as a result, the sale of commercial real estate assets and non-regulated generation assets did not meet the new criteria for discontinued operations. The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period
Effective January 1, 2015, the Corporation early adopted amendments to ASC 718, Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period, as outlined in ASU No. 2014-12. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2015.

FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers
In May 2014 the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-09, *Revenue from Contracts with Customers*. The amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. In August 2015 FASB issued ASU No. 2015-14, *Deferral of the Effective Date*. The amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The Corporation is assessing the impact that the adoption of this standard will have on its consolidated financial statements.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern
In August 2014 FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods ending after December 15, 2016. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items
In January 2015 FASB issued ASU No. 2015-01, *Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items*. The amendments in this update are part of FASB's initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Amendments to the Consolidation Analysis

In February 2015 FASB issued ASU No. 2015-02, *Amendments to the Consolidation Analysis*. The amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

In April 2015 FASB issued ASU No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update would require that debt issuance costs be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. This update is effective for annual and interim periods beginning after December 15, 2015 and should be applied on a retrospective basis. Early adoption is permitted. The adoption of this update will result in the reclassification of debt issuance costs from long-term other assets to long-term debt on the Corporation's consolidated balance sheet. As at September 30, 2015, debt issuance costs included in long-term other assets were approximately $72 million (December 31, 2014 - $67 million). Additionally, in August 2015 FASB issued ASU No. 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* The guidance in ASU No. 2015-03 does not address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements. The amendments in ASU No. 2015-15 permit an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Simplifying the Measurement of Inventory

In July 2015 FASB issued ASU No. 2015-11, *Simplifying the Measurement of Inventory*. The amendments in this update would change the subsequent measurement of inventory from the lower of cost or market to the lower of cost and net realizable value. This update is effective for annual and interim periods beginning after December 15, 2016 and should be applied on a prospective basis. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015 FASB issued ASU No. 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. The amendments in this update require that in a business combination, an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. This update is effective for annual and interim periods beginning after December 15, 2015 and should be applied on a prospective basis. 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 regulated utilities operate often require amounts to be recognized 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. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

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 nine months ended September 30, 2015 from those disclosed in the 2014 Annual MD&A, with the exception of depreciation and amortization at FortisAlberta as discussed below.

Depreciation and Amortization: Effective January 1, 2015, FortisAlberta's depreciation and amortization rates were changed as a result of an update to its last depreciation study, which was completed as of December 31, 2010. As a result, depreciation and amortization expense decreased by approximately $3 million and $6 million for the three and nine months ended September 30, 2015, respectively.

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 adverse effect on the Corporation's consolidated financial position or results of operations. The following describes the nature of the Corporation's contingencies.

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with the Federal Energy Regulatory Commission ("FERC"), alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action and in October 2015 FERC denied this request.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to Wilmington Trust Company, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the third-party owners' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the third-party owners to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 by October 22, 2015, and ordering that they timely pay their share of all future Springerville Unit 1 expenses and expenditures during the pendency of the arbitration. Any amounts collected could be subject to refund if the arbitration panel subsequently upholds all or portions of the third-party owners' claims. The arbitration panel denied the third-party owners' motion for interim relief which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. On October 20, 2015, the third-party owners informed the arbitration panel that the owner trustees have no available funds and are unable to make the payments required by the interim order, and requested that the panel reconsider its associated decision in the interim order. In a letter dated October 27, 2015, the arbitration panel indicated that it reconsidered its decision and declined to change it. The arbitration hearing is scheduled for July 2016.

On October 30, 2015, TEP filed a petition to confirm the interim arbitration order in the U.S. District Court for the Southern District of New York naming the third-party owners as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act.

As at September 30, 2015, TEP billed the third-party owners approximately US$17 million for their pro-rata share of Springerville Unit 1 expenses and US$2 million for their pro-rata share of capital expenditures, none of which had been paid as of November 5, 2015.

Under the Springerville Unit 1 facility support agreement, TEP is permitted to dispatch and use any of the third-party owners' unscheduled entitlement share of power from Springerville Unit 1. TEP commenced such dispatch and use for TEP's benefit in June 2015.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

San Juan Generating Station

San Juan Coal Company ("SJCC") operates an underground coal mine in an area where certain gas producers have oil and gas leases with the Government of the United States, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. The Company cannot reasonably estimate the impact of any future claims by these gas producers and, accordingly, no amount has been accrued in the consolidated financial statements.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. Upon expiration of the coal supply agreements, which expire between 2017 and 2031, TEP's share of reclamation costs at all three mines is expected to be US$37 million in total. The mine reclamation liability recorded as at September 30, 2015 was US$24 million (December 31, 2014 - US$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Site Investigation and Remediation Program

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 1800s, with all sites ceasing operations by the 1950s. 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, 2015, an obligation of US$104 million was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 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, 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. In the three-year Rate Order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018.

Asbestos Litigation

Prior to and after the acquisition of CH Energy Group, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,168 remained pending as at September 30, 2015. Of the cases no longer pending against Central Hudson, 2,026 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding 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 consolidated financial statements.

FortisBC Electric

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 include 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 notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis
Following the announcement of the acquisition of UNS Energy on December 11, 2013, four complaints which named Fortis and other defendants were filed in the Superior Court of the State of Arizona ("Superior Court") in and for the County of Pima and one claim in the United States District Court in and for the District of Arizona, challenging the acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the acquisition and that UNS Energy, Fortis, FortisUS Inc., and Color Acquisition Sub Inc. aided and abetted that breach. In March 2014 two of the four complaints filed in the Superior Court were dismissed by the plaintiffs and counsel for the parties in the two actions remaining in the Superior Court executed a Memorandum of Understanding recording an agreement-in-principle on the structure of a settlement to be proposed to the Superior Court for approval following closing of the acquisition. In April 2014 the complaint filed in the United States District Court was dismissed by the plaintiff, and in August 2015 the case was settled for less than $1 million.

FHI
In April 2013 FHI and Fortis were named as defendants in an action in the B.C. 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 consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2013 through September 30, 2015. 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)		**Net Earnings Attributable to Common Equity**		
	Revenue	**Shareholders**	**Earnings per Common Share**	
Quarter Ended	*($ millions)*	*($ millions)*	**Basic** *($)*	**Diluted** *($)*
September 30, 2015	1,566	151	0.54	0.54
June 30, 2015	1,538	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66
December 31, 2013	1,229	100	0.47	0.47

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas 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 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 FortisBC Energy are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

September 2015 / September 2014: Net earnings attributable to common equity shareholders were $151 million, or $0.54 per common share, for the third quarter of 2015 compared to earnings of $14 million, or $0.06 per common share, for the third quarter of 2014. A discussion of the quarter over quarter variance in financial results is provided in the "Financial Highlights" section of this MD&A.

June 2015 / June 2014: Net earnings attributable to common equity shareholders were $244 million, or $0.88 per common share, for the second quarter of 2015 compared to earnings of $47 million, or $0.22 per common share, for the second quarter of 2014. The increase was driven by a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets. The increase was also due to earnings contribution of $52 million at UNS Energy and $12 million from the Waneta Expansion, representing the Corporation's 51% controlling ownership. Performance was also driven by the Corporation's regulated utilities, including higher capital tracker revenue for 2015, customer growth and a decrease in depreciation and amortization at FortisAlberta; increases at FortisBC Electric, largely due to timing of quarterly earnings compared to the same periods last year, resulting from the impact of regulatory deferral mechanisms; and improved performance at Central Hudson. The increase was partially offset by a $5 million decrease in earnings at FortisBC Energy due to the timing of regulatory flow-through deferral amounts, and higher preference share dividends and finance charges in the Corporate and Other segment associated with the acquisition of UNS Energy.

March 2015 / March 2014: Net earnings attributable to common equity shareholders were $198 million, or $0.72 per common share, for the first quarter of 2015 compared to earnings of $143 million, or $0.67 per common share, for the first quarter of 2014. The increase in earnings was driven by the Corporation's regulated utilities. UNS Energy contributed earnings of $20 million in the first quarter of 2015. FortisAlberta's earnings were favourably impacted by higher capital tracker revenue, including approximately $10 million associated with 2013 and 2014, and customer growth. Earnings at FortisBC Energy and FortisBC Electric were $9 million and $5 million, respectively, higher quarter over quarter, largely due to timing of quarterly earnings compared to the same periods last year resulting from the impact of regulatory deferral mechanisms. Central Hudson and Eastern Canadian Regulated Electric Utilities also reported improved performance. The increase in earnings at the regulated utilities was partially offset by lower earnings at the Corporation's non-regulated subsidiaries, largely due to decreased production in Belize as a result of lower rainfall, costs at Fortis Properties associated with the strategic review, and approximately $5 million earnings contribution in the first quarter of 2014 from Griffith to the date of sale. Corporate and Other expenses were lower quarter over quarter, due to approximately $11 million in after-tax interest expense associated with the convertible debentures in the first quarter of 2014 and a higher foreign exchange gain, partially offset by higher preference share dividends and finance charges associated with the acquisition of UNS Energy.

December 2014 / December 2013: Net earnings attributable to common equity shareholders were $113 million, or $0.44 per common share, for the fourth quarter of 2014 compared to earnings of $100 million, or $0.47 per common share, for the fourth quarter of 2013. The increase in earnings was primarily due to: (i) earnings contribution of $23 million from UNS Energy; (ii) higher earnings at FortisAlberta, driven by customer growth and the timing of operating expenses; and (iii) higher earnings at the Non-Utility segment, due to higher contribution from Fortis Properties and the impact of a net loss of approximately $2.5 million at Griffith in the fourth quarter of 2013. The increase was partially offset by higher Corporate and Other expenses and lower earnings at Central Hudson. The increase in Corporate and Other expenses was primarily due to higher finance charges and preference share dividends associated with the financing of the acquisition of UNS Energy, and approximately $4 million in after-tax interest expense associated with the convertible debentures, partially offset by a higher income tax recovery. At Central Hudson, the continued impact of higher depreciation and operating expenses during the two-year rate freeze post acquisition had an unfavourable impact on earnings. Higher storm-restoration and other non-recurring expenses also reduced earnings in the fourth quarter of 2014.

OUTLOOK

Fortis is a leader in the North American electric and gas utility business, serving more than 3 million customers. Fortis' focus, and virtually all of the Corporations' assets, are low-risk, regulated utility businesses and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one third of total assets.

Over the five-year period through 2020, the Corporation's capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to approximately $20 billion in 2020 and produce a five-year compound annual growth rate of approximately 4.5%. In addition to the base capital expenditure program, Fortis is pursuing additional investment opportunities in existing and new franchise areas, including further investment in natural-gas related infrastructure. Fortis expects this capital investment to support growth in earnings and dividends.

During the third quarter of 2015, Fortis initiated dividend guidance. Fortis is targeting annual dividend growth of 6% through 2020. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $9 billion five-year capital plan, and management's continued confidence in the strength of its diversified portfolio of assets and record of operational excellence.

SUBSEQUENT EVENT

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As at September 30, 2015, the associated assets have been classified as held for sale on the consolidated balance sheet. Net proceeds from the sale were used by the Corporation to repay credit facility borrowings and for other general corporate purposes. For further information, refer to the "Significant Items" section of this MD&A.

OUTSTANDING SHARE DATA

As at November 5, 2015, the Corporation had issued and outstanding approximately 280.2 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; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. 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 November 5, 2015 is as follows.

Conversion of Securities into Common Shares (Unaudited)
As at November 5, 2015

Security	**Number of Common Shares** *(millions)*
Stock Options	**4.5**
First Preference Shares, Series E	**5.6**
Total	**10.1**

Additional information, including the Fortis 2014 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, 2015 and 2014
(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, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	**$ 347**	$ 230
Accounts receivable and other current assets	**796**	900
Prepaid expenses	**96**	59
Inventories	**349**	321
Regulatory assets (Note 5)	**235**	295
Assets held for sale (Note 6)	**390**	-
Deferred income taxes	**124**	158
	2,337	1,963
Other assets	**354**	337
Regulatory assets (Note 5)	**2,364**	2,230
Deferred income taxes	**28**	62
Utility capital assets	**18,933**	17,152
Non-utility capital assets	**-**	664
Intangible assets	**546**	488
Goodwill	**4,075**	3,732
	$ 28,637	$ 26,628
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 19)	**$ 397**	$ 330
Accounts payable and other current liabilities	**1,386**	1,440
Regulatory liabilities (Note 5)	**235**	192
Current installments of long-term debt (Note 8)	**543**	525
Current installments of capital lease and finance obligations	**25**	208
Liabilities associated with assets held for sale (Note 6)	**3**	-
Deferred income taxes	**11**	9
	2,600	2,704
Other liabilities	**1,167**	1,141
Regulatory liabilities (Note 5)	**1,403**	1,363
Deferred income taxes	**2,069**	1,837
Long-term debt (Note 8)	**10,800**	9,976
Capital lease and finance obligations	**490**	495
	18,529	17,516
Shareholders' equity		
Common shares [(1)] (Note 9)	**5,807**	5,667
Preference shares (Note 10)	**1,820**	1,820
Additional paid-in capital	**15**	15
Accumulated other comprehensive income	**633**	129
Retained earnings	**1,359**	1,060
	9,634	8,691
Non-controlling interests	**474**	421
	10,108	9,112
	$ 28,637	$ 26,628

[(1)] *No par value. Unlimited authorized shares; 279.9 million and 276.0 million issued and outstanding as at September 30, 2015 and December 31, 2014, respectively*

Commitments and Contingencies (Notes 20 and 22, 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	
	2015	2014	**2015**	2014
Revenue	**$ 1,566**	$ 1,197	**$ 5,019**	$ 3,708
Expenses				
Energy supply costs	**533**	406	**1,897**	1,488
Operating	**461**	384	**1,392**	1,010
Depreciation and amortization	**217**	181	**652**	478
	1,211	971	**3,941**	2,976
Operating income	**355**	226	**1,078**	732
Other income (expenses), net (Note 13)	**5**	(43)	**188**	(37)
Finance charges (Note 14)	**141**	159	**416**	406
Earnings before income taxes and discontinued operations	**219**	24	**850**	289
Income tax expense (recovery) (Note 15)	**40**	(8)	**173**	40
Earnings from continuing operations	**179**	32	**677**	249
Earnings from discontinued operations, net of tax (Note 7)	**-**	-	**-**	5
Net earnings	**$ 179**	$ 32	**$ 677**	$ 254
Net earnings attributable to:				
Non-controlling interests	**$ 9**	$ 3	**$ 26**	$ 8
Preference equity shareholders	**19**	15	**58**	42
Common equity shareholders	**151**	14	**593**	204
	$ 179	$ 32	**$ 677**	$ 254
Earnings per common share from continuing operations (Note 16)				
Basic	**$ 0.54**	$ 0.06	**$ 2.13**	$ 0.93
Diluted	**$ 0.54**	$ 0.06	**$ 2.11**	$ 0.93
Earnings per common share (Note 16)				
Basic	**$ 0.54**	$ 0.06	**$ 2.13**	$ 0.95
Diluted	**$ 0.54**	$ 0.06	**$ 2.11**	$ 0.95

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	
	2015	2014	**2015**	2014
Net earnings	**$ 179**	$ 32	**$ 677**	$ 254
Other comprehensive income (loss)				
Unrealized foreign currency translation gains, net of hedging activities and tax	**253**	107	**502**	109
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax	**-**	-	**2**	-
Unrealized gains (losses) on available-for-sale investment	**1**	-	**(1)**	-
Net change in fair value of cash flow hedges, net of tax	**1**	-	**1**	-
Unrealized employee future benefits gains, net of tax	**-**	-	**-**	1
	255	107	**504**	110
Comprehensive income	**$ 434**	$ 139	**$ 1,181**	$ 364
Comprehensive income attributable to:				
Non-controlling interests	**$ 9**	$ 3	**$ 26**	$ 8
Preference equity shareholders	**19**	15	**58**	42
Common equity shareholders	**406**	121	**1,097**	314
	$ 434	$ 139	**$ 1,181**	$ 364

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	
	2015	2014	**2015**	2014
Operating activities				
Net earnings	**$ 179**	$ 32	**$ 677**	$ 254
Adjustments to reconcile net earnings to net cash provided by operating activities:				
Depreciation - capital assets	**195**	156	**586**	416
Amortization - intangible assets	**16**	15	**48**	41
Amortization - other	**6**	10	**18**	21
Deferred income tax expense	**65**	23	**104**	7
Accrued employee future benefits	**(38)**	9	**(24)**	8
Equity component of allowance for funds used during construction (Note 13)	**(6)**	(2)	**(15)**	(5)
Loss (gain) on sale of non-utility capital assets (Note 13)	**2**	-	**(131)**	-
Gain on sale of non-regulated generation assets (Note 13)	**(5)**	-	**(62)**	-
Other	**39**	33	**67**	40
Change in long-term regulatory assets and liabilities	**5**	(64)	**(71)**	(71)
Change in non-cash operating working capital (Note 17)	**(100)**	(150)	**79**	(63)
	358	62	**1,276**	648
Investing activities				
Change in other assets and other liabilities	**34**	(1)	**(22)**	3
Capital expenditures - utility capital assets	**(487)**	(316)	**(1,595)**	(815)
Capital expenditures - non-utility capital assets	**-**	(11)	**(9)**	(27)
Capital expenditures - intangible assets	**(25)**	(13)	**(79)**	(33)
Contributions in aid of construction	**17**	17	**45**	43
Purchase of assets held for sale (Note 6)	**(4)**	-	**(31)**	-
Proceeds on sale of assets (Notes 6 and 7)	**19**	-	**557**	107
Business acquisition, net of cash acquired	**-**	(2,648)	**-**	(2,648)
	(446)	(2,972)	**(1,134)**	(3,370)
Financing activities				
Change in short-term borrowings	**236**	1,463	**35**	1,402
Proceeds from convertible debentures, net of issue costs	**-**	-	**-**	561
Proceeds from long-term debt, net of issue costs	**387**	586	**1,005**	846
Repayments of long-term debt and capital lease and finance obligations	**(353)**	(157)	**(589)**	(201)
Net (repayments) borrowings under committed credit facilities	**(586)**	326	**(324)**	53
Advances from non-controlling interests	**-**	5	**19**	22
Issue of common shares, net of costs and dividends reinvested (Note 9)	**5**	5	**25**	28
Issue of preference shares, net of costs (Note 10)	**-**	587	**-**	587
Dividends				
Common shares, net of dividends reinvested	**(56)**	(51)	**(171)**	(146)
Preference shares	**(19)**	(15)	**(58)**	(42)
Subsidiary dividends paid to non-controlling interests	**(2)**	(1)	**(8)**	(6)
	(388)	2,748	**(66)**	3,104
Effect of exchange rate changes on cash and cash equivalents	**24**	8	**41**	4
Change in cash and cash equivalents	**(452)**	(154)	**117**	386
Change in cash associated with assets held for sale (Note 6)	**2**	-	**-**	-
Cash and cash equivalents, beginning of period	**797**	612	**230**	72
Cash and cash equivalents, end of period	**$ 347**	$ 458	**$ 347**	$ 458

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 9)	Preference Shares (Note 10)	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total Equity
As at January 1, 2015	**$ 5,667**	**$ 1,820**	**$ 15**	**$ 129**	**$ 1,060**	**$ 421**	**$ 9,112**
Net earnings	**-**	**-**	**-**	**-**	**651**	**26**	**677**
Other comprehensive income	**-**	**-**	**-**	**504**	**-**	**-**	**504**
Common share issues	**140**	**-**	**(2)**	**-**	**-**	**-**	**138**
Stock-based compensation	**-**	**-**	**2**	**-**	**-**	**-**	**2**
Advances from non-controlling interests	**-**	**-**	**-**	**-**	**-**	**19**	**19**
Foreign currency translation impacts	**-**	**-**	**-**	**-**	**-**	**16**	**16**
Subsidiary dividends paid to non-controlling interests	**-**	**-**	**-**	**-**	**-**	**(8)**	**(8)**
Dividends declared on common shares ($1.06 per share)	**-**	**-**	**-**	**-**	**(294)**	**-**	**(294)**
Dividends declared on preference shares	**-**	**-**	**-**	**-**	**(58)**	**-**	**(58)**
As at September 30, 2015	**$ 5,807**	**$ 1,820**	**$ 15**	**$ 633**	**$ 1,359**	**$ 474**	**$ 10,108**
As at January 1, 2014	$ 3,783	$ 1,229	$ 17	$ (72)	$ 1,044	$ 375	$ 6,376
Net earnings	-	-	-	-	246	8	254
Other comprehensive income	-	-	-	110	-	-	110
Preference share issue	-	591	-	-	-	-	591
Common share issues	90	-	(2)	-	-	-	88
Stock-based compensation	-	-	2	-	-	-	2
Advances from non-controlling interests	-	-	-	-	-	22	22
Foreign currency translation impacts	-	-	-	-	-	6	6
Unrealized losses on cash flow hedges assumed on acquisition	-	-	-	(4)	-	-	(4)
Subsidiary dividends paid to non-controlling interests	-	-	-	-	-	(6)	(6)
Dividends declared on common shares ($0.96 per share)	-	-	-	-	(206)	-	(206)
Dividends declared on preference shares	-	-	-	-	(42)	-	(42)
As at September 30, 2014	$ 3,873	$ 1,820	$ 17	$ 34	$ 1,042	$ 405	$ 7,191

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 electric and gas 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, which are treated as a separate segment. 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 with substantial autonomy, 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 2014 annual audited consolidated financial statements.

REGULATED UTILITIES

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

a. *Regulated Electric & Gas Utilities - United States:* Comprised of UNS Energy, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), acquired by Fortis in August 2014, and Central Hudson Gas & Electric Corporation ("Central Hudson").

b. *Regulated Gas Utility - Canadian:* Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company.

c. *Regulated Electric Utilities - Canadian:* Comprised of FortisAlberta Inc. ("FortisAlberta"), FortisBC Inc. ("FortisBC Electric"), and Eastern Canadian Electric Utilities (Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("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 Company, Ltd. ("Caribbean Utilities"), in which Fortis holds an approximate 60% controlling interest, two wholly owned utilities in the Turks and Caicos Islands, FortisTCI Limited and Turks and Caicos Utilities Limited (collectively "Fortis Turks and Caicos"), and also includes the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 21).

NON-REGULATED - FORTIS GENERATION

Fortis Generation is primarily comprised of non-regulated generation assets in British Columbia and Belize. On April 1, 2015, the Corporation completed construction of the $900 million Waneta Expansion hydroelectric generating facility. In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively (Note 7).

NON-REGULATED - NON-UTILITY

Fortis Properties Corporation ("Fortis Properties") completed the sale of its commercial real estate assets in June 2015 (Note 7) and its hotel assets in October 2015 (Note 23). As at September 30, 2015, the associated hotel assets have been classified as held for sale (Note 6).

Griffith Energy Services, Inc. ("Griffith") was sold in March 2014 (Note 7).

1. DESCRIPTION OF THE BUSINESS (cont'd)

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 net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group") and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). 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 2014 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 electricity and gas 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 FortisBC Energy are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment. 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 regulated utilities operate often require amounts to be recognized 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. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

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, 2015, except as follows.

Effective January 1, 2015, FortisAlberta's depreciation and amortization rates were changed as a result of a technical update to its last depreciation study, which was completed as of December 31, 2010. As a result, depreciation and amortization expense decreased by approximately $3 million and $6 million for the three and nine months ended September 30, 2015, respectively.

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

An evaluation of subsequent events through November 5, 2015, 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, 2015 (Note 23).

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. 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 2014 annual audited consolidated financial statements, except as described below.

Available-for-Sale Assets
The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
Effective January 1, 2015, the Corporation adopted amendments to Accounting Standards Codification ("ASC"), Topics 205 and 360, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity,* as outlined in Accounting Standards Update ("ASU") No. 2014-08. The amendments were applied prospectively and, as a result, the sale of commercial real estate assets and non-regulated generation assets did not meet the new criteria for discontinued operations (Note 7). The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period
Effective January 1, 2015, the Corporation early adopted amendments to ASC 718, *Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period,* as outlined in ASU No. 2014-12. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2015.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers
In May 2014 the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-09, *Revenue from Contracts with Customers*. The amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. In August 2015 FASB issued ASU No. 2015-14, *Deferral of the Effective Date*. The amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The Corporation is assessing the impact that the adoption of this standard will have on its consolidated financial statements.

3. FUTURE ACCOUNTING PRONOUNCEMENTS (cont'd)

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern
In August 2014 FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods ending after December 15, 2016. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items
In January 2015 FASB issued ASU No. 2015-01, *Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items*. The amendments in this update are part of FASB's initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Amendments to the Consolidation Analysis
In February 2015 FASB issued ASU No. 2015-02, *Amendments to the Consolidation Analysis*. The amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
In April 2015 FASB issued ASU No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update would require that debt issuance costs be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. This update is effective for annual and interim periods beginning after December 15, 2015 and should be applied on a retrospective basis. Early adoption is permitted. The adoption of this update will result in the reclassification of debt issuance costs from long-term other assets to long-term debt on the Corporation's consolidated balance sheet. As at September 30, 2015, debt issuance costs included in long-term other assets were approximately $72 million (December 31, 2014 - $67 million). Additionally, in August 2015 FASB issued ASU No. 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* The guidance in ASU No. 2015-03 does not address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements. The amendments in ASU No. 2015-15 permit an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Simplifying the Measurement of Inventory
In July 2015 FASB issued ASU No. 2015-11, *Simplifying the Measurement of Inventory*. The amendments in this update would change the subsequent measurement of inventory from the lower of cost or market to the lower of cost and net realizable value. This update is effective for annual and interim periods beginning after December 15, 2016 and should be applied on a prospective basis. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

3. FUTURE ACCOUNTING PRONOUNCEMENTS (cont'd)

Simplifying the Accounting for Measurement-Period Adjustments
In September 2015 FASB issued ASU No. 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. The amendments in this update require that in a business combination, an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. This update is effective for annual and interim periods beginning after December 15, 2015 and should be applied on a prospective basis. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

4. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
Quarter Ended	Electric & Gas			Gas	Electric								**Inter-**	
September 30, 2015	UNS	Central		FortisBC	Fortis	FortisBC	Eastern		**Caribbean**	**Fortis**	**Non-**	**Corporate**	**segment**	
($ millions)	Energy	Hudson	**Total**	Energy	Alberta	Electric	Canadian	**Total**	**Electric**	**Generation**	**Utility**	**and Other**	**eliminations**	**Total**
Revenue	623	193	**816**	168	141	85	206	**600**	**87**	**29**	**47**	**8**	**(21)**	**1,566**
Energy supply costs	242	59	**301**	47	-	30	122	**199**	**46**	**-**	**-**	**-**	**(13)**	**533**
Operating expenses	146	94	**240**	69	44	21	33	**167**	**11**	**4**	**34**	**8**	**(3)**	**461**
Depreciation and amortization	61	14	**75**	47	42	14	21	**124**	**12**	**6**	**-**	**-**	**-**	**217**
Operating income	174	26	**200**	5	55	20	30	**110**	**18**	**19**	**13**	**-**	**(5)**	**355**
Other income (expenses), net	-	2	**2**	2	1	-	1	**4**	**-**	**5**	**(2)**	**(4)**	**-**	**5**
Finance charges	25	10	**35**	34	20	9	14	**77**	**3**	**1**	**5**	**25**	**(5)**	**141**
Income tax expense (recovery)	52	7	**59**	(7)	(1)	3	4	**(1)**	**-**	**-**	**(5)**	**(13)**	**-**	**40**
Net earnings (loss)	97	11	**108**	(20)	37	8	13	**38**	**15**	**23**	**11**	**(16)**	**-**	**179**
Non-controlling interests	-	-	**-**	-	-	-	-	**-**	**4**	**5**	**-**	**-**	**-**	**9**
Preference share dividends	-	-	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**19**	**-**	**19**
Net earnings (loss) attributable to common equity shareholders	97	11	**108**	(20)	37	8	13	**38**	**11**	**18**	**11**	**(35)**	**-**	**151**
Goodwill	1,842	602	**2,444**	913	227	235	67	**1,442**	**189**	**-**	**-**	**-**	**-**	**4,075**
Identifiable assets	6,849	2,483	**9,332**	4,980	3,518	1,864	2,171	**12,533**	**1,053**	**1,025**	**381**	**648**	**(410)**	**24,562**
Total assets	8,691	3,085	**11,776**	5,893	3,745	2,099	2,238	**13,975**	**1,242**	**1,025**	**381**	**648**	**(410)**	**28,637**
Gross capital expenditures	103	56	**159**	125	99	23	42	**289**	**51**	**12**	**-**	**1**	**-**	**512**
Quarter Ended September 30, 2014 *($ millions)*														
Revenue	249	173	**422**	208	131	78	198	**615**	**85**	**8**	**68**	**9**	**(10)**	**1,197**
Energy supply costs	95	61	**156**	68	-	18	115	**201**	**50**	**-**	**-**	**-**	**(1)**	**406**
Operating expenses	61	79	**140**	72	43	22	33	**170**	**13**	**3**	**44**	**16**	**(2)**	**384**
Depreciation and amortization	26	12	**38**	50	40	16	20	**126**	**9**	**1**	**6**	**1**	**-**	**181**
Operating income	67	21	**88**	18	48	22	30	**118**	**13**	**4**	**18**	**(8)**	**(7)**	**226**
Other income (expenses), net	1	2	**3**	-	(1)	1	1	**1**	**1**	**-**	**-**	**(48)**	**-**	**(43)**
Finance charges	11	9	**20**	35	21	11	13	**80**	**3**	**-**	**6**	**57**	**(7)**	**159**
Income tax expense (recovery)	20	6	**26**	(4)	(1)	3	5	**3**	**-**	**-**	**3**	**(40)**	**-**	**(8)**
Net earnings (loss)	37	8	**45**	(13)	27	9	13	**36**	**11**	**4**	**9**	**(73)**	**-**	**32**
Non-controlling interests	-	-	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	-	-	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**15**	**-**	**15**
Net earnings (loss) attributable to common equity shareholders	37	8	**45**	(13)	27	9	13	**36**	**8**	**4**	**9**	**(88)**	**-**	**14**
Goodwill	1,547	505	**2,052**	913	227	235	67	**1,442**	**158**	**-**	**-**	**-**	**-**	**3,652**
Identifiable assets	5,171	1,979	**7,150**	4,668	3,435	1,779	2,094	**11,976**	**867**	**932**	**700**	**2,039**	**(576)**	**23,088**
Total assets	6,718	2,484	**9,202**	5,581	3,662	2,014	2,161	**13,418**	**1,025**	**932**	**700**	**2,039**	**(576)**	**26,740**
Gross capital expenditures	45	35	**80**	75	83	20	42	**220**	**14**	**15**	**11**	**-**	**-**	**340**

4. SEGMENTED INFORMATION (cont'd)

	REGULATED									NON-REGULATED				
	United States			Canada										
Year-to-Date	Electric & Gas			Gas	Electric									
September 30, 2015	UNS	Central		FortisBC	Fortis	FortisBC	Eastern		**Caribbean**	**Fortis**	**Non-**	**Corporate**	**Inter-segment**	
($ millions)	Energy	Hudson	**Total**	Energy	Alberta	Electric	Canadian	**Total**	**Electric**	**Generation**	**Utility**	**and Other**	**eliminations**	**Total**
Revenue	1,552	678	**2,230**	884	423	261	760	**2,328**	**239**	**77**	**165**	**22**	**(42)**	**5,019**
Energy supply costs	626	257	**883**	337	-	76	489	**902**	**127**	**1**	**-**	**-**	**(16)**	**1,897**
Operating expenses	418	284	**702**	205	133	65	106	**509**	**34**	**12**	**119**	**25**	**(9)**	**1,392**
Depreciation and amortization	178	42	**220**	143	125	43	62	**373**	**34**	**13**	**11**	**1**	**-**	**652**
Operating income	330	95	**425**	199	165	77	103	**544**	**44**	**51**	**35**	**(4)**	**(17)**	**1,078**
Other income (expenses), net	2	6	**8**	7	2	-	1	**10**	**1**	**57**	**109**	**4**	**(1)**	**188**
Finance charges	73	29	**102**	102	59	28	42	**231**	**11**	**2**	**18**	**70**	**(18)**	**416**
Income tax expense (recovery)	90	29	**119**	28	(1)	7	15	**49**	**-**	**24**	**13**	**(32)**	**-**	**173**
Net earnings (loss)	169	43	**212**	76	109	42	47	**274**	**34**	**82**	**113**	**(38)**	**-**	**677**
Non-controlling interests	-	-	**-**	1	-	-	-	**1**	**9**	**16**	**-**	**-**	**-**	**26**
Preference share dividends	-	-	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**58**	**-**	**58**
Net earnings (loss) attributable to common equity shareholders	169	43	**212**	75	109	42	47	**273**	**25**	**66**	**113**	**(96)**	**-**	**593**
Goodwill	1,842	602	**2,444**	913	227	235	67	**1,442**	**189**	**-**	**-**	**-**	**-**	**4,075**
Identifiable assets	6,849	2,483	**9,332**	4,980	3,518	1,864	2,171	**12,533**	**1,053**	**1,025**	**381**	**648**	**(410)**	**24,562**
Total assets	8,691	3,085	**11,776**	5,893	3,745	2,099	2,238	**13,975**	**1,242**	**1,025**	**381**	**648**	**(410)**	**28,637**
Gross capital expenditures	552	123	**675**	364	306	83	115	**868**	**95**	**31**	**9**	**5**	**-**	**1,683**
Year-to-Date September 30, 2014 *($ millions)*														
Revenue	249	635	**884**	1,003	386	244	742	**2,375**	**237**	**30**	**187**	**24**	**(29)**	**3,708**
Energy supply costs	95	277	**372**	438	-	62	476	**976**	**141**	**1**	**-**	**-**	**(2)**	**1,488**
Operating expenses	61	248	**309**	210	128	65	106	**509**	**32**	**7**	**129**	**30**	**(6)**	**1,010**
Depreciation and amortization	26	35	**61**	142	122	44	59	**367**	**27**	**4**	**17**	**2**	**-**	**478**
Operating income	67	75	**142**	213	136	73	101	**523**	**37**	**18**	**41**	**(8)**	**(21)**	**732**
Other income (expenses), net	1	5	**6**	2	1	1	2	**6**	**2**	**(1)**	**-**	**(49)**	**(1)**	**(37)**
Finance charges	11	26	**37**	105	60	30	42	**237**	**11**	**-**	**18**	**125**	**(22)**	**406**
Income tax expense (recovery)	20	21	**41**	31	(1)	10	15	**55**	**-**	**1**	**7**	**(64)**	**-**	**40**
Net earnings (loss) from continuing operations	37	33	**70**	79	78	34	46	**237**	**28**	**16**	**16**	**(118)**	**-**	**249**
Earnings from discontinued operations, net of tax	-	-	**-**	-	-	-	-	**-**	**-**	**-**	**5**	**-**	**-**	**5**
Net earnings (loss)	37	33	**70**	79	78	34	46	**237**	**28**	**16**	**21**	**(118)**	**-**	**254**
Non-controlling interests	-	-	**-**	1	-	-	-	**1**	**7**	**-**	**-**	**-**	**-**	**8**
Preference share dividends	-	-	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**42**	**-**	**42**
Net earnings (loss) attributable to common equity shareholders	37	33	**70**	78	78	34	46	**236**	**21**	**16**	**21**	**(160)**	**-**	**204**
Goodwill	1,547	505	**2,052**	913	227	235	67	**1,442**	**158**	**-**	**-**	**-**	**-**	**3,652**
Identifiable assets	5,171	1,979	**7,150**	4,668	3,435	1,779	2,094	**11,976**	**867**	**932**	**700**	**2,039**	**(576)**	**23,088**
Total assets	6,718	2,484	**9,202**	5,581	3,662	2,014	2,161	**13,418**	**1,025**	**932**	**700**	**2,039**	**(576)**	**26,740**
Gross capital expenditures	45	84	**129**	200	244	58	105	**607**	**42**	**70**	**27**	**-**	**-**	**875**

4. 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 for the three and nine months ended September 30, 2015 and 2014 were as follows:

Significant Related Party Inter-Segment Transactions	**Quarter Ended September 30**		**Year-to-Date September 30**	
($ millions)	**2015**	2014	**2015**	2014
Sales from Fortis Generation to Regulated Electric Utilities - Canadian	**12**	1	**15**	2
Revenue from Regulated Electric Utilities - Canadian to Fortis Generation	**3**	-	**3**	-
Sales from Regulated Electric Utilities - Canadian to Non-Utility	**1**	1	**4**	4
Inter-segment finance charges on lending from:				
Corporate to Regulated Electric Utilities - Canadian	**-**	-	**-**	1
Corporate to Regulated Electric Utilities - Caribbean	**-**	1	**-**	4
Corporate to Non-Utility	**5**	6	**17**	16

The significant related party inter-segment asset balances were as follows:

	As at September 30	
($ millions)	**2015**	2014
Inter-segment lending from:		
Fortis Generation to Eastern Canadian Electric Utilities	**20**	20
Corporate to Regulated Gas Utility - Canadian	**-**	18
Corporate to Regulated Electric Utilities - Canadian	**-**	25
Corporate to Regulated Electric Utilities - Caribbean	**-**	101
Corporate to Non-Utility	**364**	396
Other inter-segment assets	**26**	16
Total inter-segment eliminations	**410**	576

5. 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 2014 annual audited consolidated financial statements.

($ millions)	As at September 30, 2015	December 31, 2014
Regulatory assets		
Deferred income taxes	**1,007**	942
Employee future benefits *(i)*	**654**	680
Deferred energy management costs	**133**	111
Manufactured gas plant ("MGP") site remediation deferral (Note 22)	**132**	123
Rate stabilization accounts	**97**	119
Deferred lease costs	**96**	101
Derivative instruments (Note 18)	**63**	69
Deferred operating overhead costs	**63**	54
Final mine reclamation and retiree health care costs	**37**	34
Deferred net losses on disposal of utility capital assets and intangible assets	**34**	37
Springerville Unit 1 unamortized leasehold improvements *(ii)*	**30**	-
Property tax deferrals	**29**	29
Natural gas for transportation incentives	**25**	24
Income taxes recoverable on other post-employment benefit ("OPEB") plans	**24**	24
Carrying charges - employee future benefits *(i)*	**-**	20
Other regulatory assets *(i)*	**175**	158
Total regulatory assets	**2,599**	2,525
Less: current portion	**(235)**	(295)
Long-term regulatory assets	**2,364**	2,230

($ millions)	As at September 30, 2015	December 31, 2014
Regulatory liabilities		
Non-asset retirement obligation removal cost provision	**1,031**	951
Rate stabilization accounts	**153**	142
Deferred income taxes	**95**	110
Electric and gas moderator account *(i)*	**87**	-
Renewable energy surcharge	**44**	44
Employee future benefits *(i)*	**38**	58
Customer and community benefits obligation *(i)*	**34**	55
Energy efficiency liability	**28**	22
Alberta Electric System Operator charges deferral	**24**	49
Carrying charges - employee future benefits *(i)*	**-**	24
Other regulatory liabilities *(i)*	**104**	100
Total regulatory liabilities	**1,638**	1,555
Less: current portion	**(235)**	(192)
Long-term regulatory liabilities	**1,403**	1,363

5. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities

(i) In June 2015 the New York State Public Service Commission ("PSC") issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. Under the terms of the Rate Order, certain regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation.

(ii) Upon expiration of TEP's Springerville Unit 1 capital lease in January 2015, unamortized leasehold improvements were reclassified from utility capital assets to regulatory assets. The leasehold improvements represent investments made by TEP through the end of the lease term to ensure Springerville facilities continued providing safe, reliable service to TEP's customers. In its 2013 rate order, TEP received regulatory approval to amortize the leasehold improvements over a 10-year period. TEP continues to own an undivided 49.5% joint interest in Springerville Unit 1.

6. ASSETS HELD FOR SALE

Assets held for sale as at September 30, 2015 were as follows:

	As at September 30, 2015		
($ millions)	Regulated UNS Energy	Non-Regulated Non-Utility	**Total**
ASSETS			
Current assets	-	2	**2**
Utility capital assets	28	-	**28**
Non-utility capital assets	-	374	**374**
Total assets held for sale	28	376	**404**
Impairment (Note 13)	-	(14)	**(14)**
Net assets held for sale	28	362	**390**
LIABILITIES			
Accounts payable and other current liabilities	-	3	**3**
Total liabilities associated with assets held for sale	-	3	**3**

REGULATED

UNS Energy

In April 2015, upon expiration of the Springerville Coal Handling Facilities lease, UNS Energy purchased an additional ownership interest in the previously leased coal handling assets for a total of US$120 million. In May 2015 UNS Energy sold a 17.05% interest in the facilities to a third party for US$24 million and has an agreement with another third party to either purchase a 17.05% interest for US$24 million or to continue to make payments to UNS Energy for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the associated assets have been classified as held for sale on the consolidated balance sheet as at September 30, 2015.

6. ASSETS HELD FOR SALE (cont'd)

NON-REGULATED

Non-Utility

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million (Note 23). As at September 30, 2015, the associated assets have been classified as held for sale on the consolidated balance sheet. For the three and nine months ended September 30, 2015, impairment losses associated with these hotel assets of $1 million and $14 million, respectively, were recognized, reflecting a reduction in the carrying value of the assets to the estimated fair value based on the selling price, as well as estimated costs to sell. An additional $1 million and $6 million in expenses associated with the sale of the hotel assets were recognized for the three and nine months ended September 30, 2015, respectively (Note 13).

For the three and nine months ended September 30, 2015, earnings before taxes related to the hotels of approximately $8 million and $9 million, respectively, were recognized compared to $8 million and $10 million for the three and nine months ended September 30, 2014, respectively, excluding the impairment loss on the assets held for sale and expenses associated with the sale.

7. DISPOSITIONS AND DISCONTINUED OPERATIONS

Sale of Commercial Real Estate Assets

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses in the second quarter of 2015 (Note 13). Earnings before taxes related to the commercial real estate assets of approximately $8 million were recognized in the first half of 2015, excluding the gain on sale, compared to $4 million and $13 million for the three and nine months ended September 30, 2014, respectively.

As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The investment in trust units is recorded as an available-for-sale asset and recognized in long-term other assets on the Corporation's consolidated balance sheet (Notes 2 and 18).

Sale of Non-Regulated Generation Assets

In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts, in the second quarter of 2015 (Note 13).

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) for the three and nine months ended September 30, 2015 (Note 13).

For the three and nine months ended September 30, 2015, earnings before taxes of less than $1 million were recognized, excluding the gain on sale, compared to $2 million and $3 million for the three and nine months ended September 30, 2014, respectively.

Sale of Griffith

In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The results of operations to the date of sale are presented as discontinued operations on the consolidated statements of earnings. As a result of the disposal, earnings from discontinued operations of $8 million ($5 million after tax) were recognized in the first quarter of 2014.

8. LONG-TERM DEBT

	As at	
($ millions)	**September 30, 2015**	December 31, 2014
Long-term debt	**10,511**	9,405
Long-term classification of credit facility borrowings (Note 19)	**832**	1,096
Total long-term debt	**11,343**	10,501
Less: Current installments of long-term debt	**(543)**	(525)
	10,800	9,976

The significant changes in long-term debt from that disclosed in the Corporation's 2014 annual audited consolidated financial statements are as follows.

In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures.

In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used to repay short-term borrowings.

In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured debentures and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt and for general corporate purposes. Additionally, in August 2015 TEP redeemed at par US$79 million of variable rate tax-exempt bonds that had an original maturity date of 2022.

In September 2015 FortisAlberta issued 30-year $150 million 4.27% unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

9. COMMON SHARES

Common shares issued during the period were as follows:

	Quarter Ended September 30, 2015		Year-to-Date September 30, 2015	
	Number of Shares *(in thousands)*	Amount *($ millions)*	Number of Shares *(in thousands)*	Amount *($ millions)*
Balance, beginning of period	278,622	5,762	275,997	5,667
Dividend Reinvestment Plan	1,107	40	3,057	113
Consumer Share Purchase Plan	7	-	20	1
Employee Share Purchase Plan	77	3	286	11
Stock Option Plans	64	2	506	15
Conversion of convertible debentures (Note 14)	9	-	20	-
Balance, end of period	279,886	5,807	279,886	5,807

10. PREFERENCE SHARES

On each conversion date of the Cumulative Redeemable First Preference Shares, Series H ("First Preference Shares, Series H"), the holders of First Preference Shares, Series H have the option to convert any or all of their First Preference Shares, Series H, into an equal number of Cumulative Redeemable Floating Rate First Preference Shares, Series I ("First Preference Shares, Series I"). On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.

The holders for First Preference Shares, Series I are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation, for the five-year period beginning after June 1, 2015. The floating quarterly dividend rate will be reset every quarter based on the then current 3-month Government of Canada Treasury Bill rate plus 1.45%. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.

In September 2014 the Corporation issued 24 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M at a price of $25.00 per share for net after-tax proceeds of $591 million.

11. STOCK-BASED COMPENSATION PLANS

Stock Options

In March 2015 the Corporation granted 667,244 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 $39.25. 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 $2.46 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 (%)	3.6
Expected volatility (%)	14.6
Risk-free interest rate (%)	0.9
Weighted average expected life (years)	5.5

Directors' Deferred Share Unit Plan

In January 2015, 6,394 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 and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

In April 2015, 5,730 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 2015, 8,406 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.

Share Unit Plans

The Corporation has the following share unit plans that represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries: (i) Performance Share Unit ("PSU") Plans, including the 2013 PSU Plan and 2015 PSU Plan; and (ii) the 2015 Restricted Share Unit ("RSU") Plan. In addition, certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each share unit has 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 respective Board of Directors. The share unit plans differ in payout criteria, with the PSU plans having certain performance and market criteria and the RSU plan subject only to the vesting period. Each unit is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

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

Year-to-date 2015, a total of 335,904 share units were granted to senior management of the Corporation and its subsidiaries.

In January 2015, 68,759 PSUs were paid out to the former Chief Executive Officer ("CEO") of the Corporation at $38.90 per PSU, for a total of approximately $3 million. The payout was made in respect of the PSU grant made in March 2012 and the former CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the three and nine months ended September 30, 2015, stock-based compensation expense of approximately $5 million and $13 million, respectively, was recognized ($4 million and $9 million for the three and nine months ended September 30, 2014, respectively).

12. 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 and group 401(k) 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 table.

	Quarter Ended September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2015**	2014	**2015**	2014
Components of net benefit cost:				
Service costs	**17**	12	**3**	3
Interest costs	**28**	23	**6**	5
Expected return on plan assets	**(37)**	(28)	**(4)**	(2)
Amortization of actuarial losses	**16**	8	**1**	1
Amortization of past service costs (credits)	**-**	1	**(2)**	(2)
Regulatory adjustments	**1**	2	**2**	2
Net benefit cost	**25**	18	**6**	7

	Year-to-Date September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2015**	2014	**2015**	2014
Components of net benefit cost:				
Service costs	**51**	31	**12**	8
Interest costs	**82**	64	**17**	15
Expected return on plan assets	**(106)**	(76)	**(9)**	(6)
Amortization of actuarial losses	**44**	23	**3**	3
Amortization of past service costs (credits)	**1**	1	**(8)**	(7)
Regulatory adjustments	**-**	7	**5**	5
Net benefit cost	**72**	50	**20**	18

For the three and nine months ended September 30, 2015, the Corporation expensed $8 million and $22 million, respectively ($5 million and $15 million for the three and nine months ended September 30, 2014, respectively), related to defined contribution pension plans.

13. OTHER INCOME (EXPENSES), NET

($ millions)	Quarter Ended September 30 **2015**	2014	Year-to-Date September 30 **2015**	2014
Equity component of allowance for funds used during construction ("AFUDC")	**6**	2	**15**	5
Gain on sale of commercial real estate assets (Note 7) [(1)]	**-**	-	**129**	-
Impairment of hotel assets held for sale (Note 6) [(2)]	**(2)**	-	**(20)**	-
Gain on sale of non-regulated generation assets (Note 7) [(3)]	**5**	-	**56**	-
Net foreign exchange gain	**5**	5	**13**	5
Loss on settlement of expropriation matters (Note 21)	**(9)**	-	**(9)**	-
Interest income	**2**	3	**6**	10
Acquisition-related expenses	**-**	(20)	**-**	(24)
Acquisition-related customer and community benefits	**-**	(33)	**-**	(33)
Other	**(2)**	-	**(2)**	-
	5	(43)	**188**	(37)

(1) Net of $17 million of expenses associated with the sale
(2) Includes a $14 million impairment and $6 million of expenses associated with the sale
(3) Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 21). Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity will be recognized on the balance sheet in accumulated other comprehensive income.

The acquisition-related expenses and customer and community benefits were associated with the acquisition of UNS Energy in August 2014.

14. FINANCE CHARGES

($ millions)	Quarter Ended September 30 **2015**	2014	Year-to-Date September 30 **2015**	2014
Interest:				
Long-term debt and capital lease and finance obligations	**145**	124	**428**	344
Convertible debentures	**-**	33	**-**	67
Short-term borrowings	**1**	8	**6**	13
Debt component of AFUDC	**(5)**	(6)	**(18)**	(18)
	141	159	**416**	406

In January 2014 Fortis completed the sale of $1.8 billion aggregate principal amount of 4% convertible debentures to finance a portion of the acquisition of UNS Energy. The convertible debentures were sold on an installment basis at a price of $1,000 per convertible debenture, of which $333 was paid on closing with the remaining final installment of $667 paid in October 2014. Substantially all of the convertible debentures have been converted into approximately 58.5 million common shares of Fortis.

15. 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)	**2015**	2014	**2015**	2014
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	**64**	7	**247**	84
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(4)**	(2)	**(5)**	(7)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**-**	-	**(8)**	(7)
Items capitalized for accounting purposes but expensed for income tax purposes	**(9)**	(9)	**(39)**	(31)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	**(8)**	-	**(21)**	-
Other	**(3)**	(4)	**(1)**	1
Income tax expense (recovery)	**40**	(8)	**173**	40
Effective income tax rate	**18.3%**	(33.3%)	**20.4%**	13.8%

16. 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.

EPS was as follows:

	Quarter Ended September 30, 2015						
	Net Earnings to Common Shareholders			Weighted Average	EPS		
	Continuing Operations ($ millions)	Discontinued Operations ($ millions)	Total ($ millions)	Number of Shares (millions)	Continuing Operations	Discontinued Operations	Total
Basic EPS	151	-	151	279.1	$0.54	$-	$0.54
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.8			
Preference Shares	2	-	2	5.4			
Diluted EPS	153	-	153	285.3	$0.54	$-	$0.54

	Quarter Ended September 30, 2014						
	Net Earnings to Common Shareholders			Weighted Average	EPS		
	Continuing Operations ($ millions)	Discontinued Operations ($ millions)	Total ($ millions)	Number of Shares (millions)	Continuing Operations	Discontinued Operations	Total
Basic EPS	14	-	14	215.6	$0.06	$-	$0.06
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.5			
Preference Shares	2	-	2	6.9			
	16	-	16	223.0			
Deduct anti-dilutive impacts:							
Preference Shares	(2)	-	(2)	(6.9)			
Diluted EPS	14	-	14	216.1	$0.06	$-	$0.06

	Year-to-Date September 30, 2015						
	Net Earnings to Common Shareholders			Weighted Average	EPS		
	Continuing Operations ($ millions)	Discontinued Operations ($ millions)	Total ($ millions)	Number of Shares (millions)	Continuing Operations	Discontinued Operations	Total
Basic EPS	593	-	593	277.9	$2.13	$-	$2.13
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.8			
Preference Shares	7	-	7	5.4			
Diluted EPS	600	-	600	284.1	$2.11	$-	$2.11

	Year-to-Date September 30, 2014						
	Net Earnings to Common Shareholders			Weighted Average	EPS		
	Continuing Operations ($ millions)	Discontinued Operations ($ millions)	Total ($ millions)	Number of Shares (millions)	Continuing Operations	Discontinued Operations	Total
Basic EPS	199	5	204	214.6	$0.93	$0.02	$0.95
Effect of potential dilutive securities:							
Stock Options	-	-	-	0.5			
Preference Shares	7	-	7	6.9			
	206	5	211	222.0			
Deduct anti-dilutive impacts:							
Preference Shares	(7)	-	(7)	(6.9)			
Diluted EPS	199	5	204	215.1	$0.93	$0.02	$0.95

17. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended September 30		Year-to-Date September 30	
($ millions)	**2015**	2014	**2015**	2014
Change in non-cash operating working capital:				
Accounts receivable and other current assets	**51**	83	**144**	171
Prepaid expenses	**(42)**	(30)	**(32)**	(16)
Inventories	**(48)**	(67)	**(6)**	(51)
Regulatory assets - current portion	**28**	18	**60**	17
Accounts payable and other current liabilities	**(77)**	(128)	**(79)**	(162)
Regulatory liabilities - current portion	**(12)**	(26)	**(8)**	(22)
	(100)	(150)	**79**	(63)
Non-cash investing and financing activities:				
Common share dividends reinvested	**38**	18	**112**	60
Additions to utility and non-utility capital assets, and intangible assets included in current liabilities	**197**	187	**197**	187
Contributions in aid of construction included in current assets	**6**	10	**6**	10
Exercise of stock options into common shares	**-**	-	**2**	2
Convertible debentures represented by installment receipts	**-**	1,201	**-**	1,201

18. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

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 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.

18. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

		As at	
($ millions)	**Fair value hierarchy**	**September 30, 2015**	December 31, 2014
Assets			
Energy contracts subject to regulatory deferral (1) (2) (3)	Levels 2/3	**2**	3
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**3**	1
Available-for-sale investment (4) (5)	Level 1	**34**	-
Assets held for sale (Note 6)	Level 2	**362**	-
Other investments (4)	Level 1	**12**	5
Total gross assets		**413**	9
Less: Counterparty netting not offset on the balance sheet (6)		**(2)**	(3)
Total net assets		**411**	6
Liabilities			
Energy contracts subject to regulatory deferral (1) (2) (7)	Levels 1/2/3	**65**	72
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**-**	1
Energy contracts - cash flow hedges (2) (8)	Level 3	**-**	1
Interest rate swaps - cash flow hedges (8)	Level 2	**5**	5
Total gross liabilities		**70**	79
Less: Counterparty netting not offset on the balance sheet (6)		**(2)**	(3)
Total net liabilities		**68**	76

(1) The fair value of the Corporation's energy contracts are recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

(3) Includes less than $1 million - level 2 and $1 million - level 3 (2014 - $3 million - level 3)

(4) Included in long-term other assets on the consolidated balance sheet

(5) The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings (Note 7).

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

(7) Includes $1 million – level 1, $44 million - level 2 and $20 million - level 3 (2014 - $2 million - level 1, $35 million - level 2 and $35 million - level 3)

(8) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

18. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation is required to record all derivative instruments at fair value, except for those that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments 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.

Energy Contracts Subject to Regulatory Deferral
UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts are estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums 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 derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at September 30, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at September 30, 2015, unrealized losses of $63 million (December 31, 2014 - $69 million) were recognized in current regulatory assets and no unrealized gains were recognized in regulatory liabilities (Note 5).

Energy Contracts Not Subject to Regulatory Deferral
In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges
UNS Energy holds interest rate swaps, expiring through 2020, to mitigate its exposure to volatility in variable interest rates on debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

18. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Derivative Instruments (cont'd)

Cash Flow Hedges (cont'd)
Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

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

Volume of Derivative Activity

As at September 30, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	**Maturity** *(year)*	**Contracts** *(#)*	**2015**	**2016**	**2017**	**2018**	**2019**	**There-after**
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (gigawatt hours *("GWh")*)	2017	6	295	713	219	-	-	-
Electricity power purchase contracts *(GWh)*	2017	23	271	780	145	-	-	-
Gas swap and option contracts (petajoules ("*PJ*"))	2018	176	11	29	8	1	-	-
Gas purchase contract premiums *(PJ)*	2024	94	39	87	40	37	22	87
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	663	1,310	-	-	-	-

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. 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:

Asset (Liability)	**As at September 30, 2015**		December 31, 2014	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset - Belize Electricity [(1)]	**-**	**-**	116	n/a
Long-term debt, including current portion (Note 8) [(2)]	**(11,343)**	**(12,721)**	(10,501)	(12,237)
Waneta Expansion Limited Partnership ("Waneta Partnership") promissory note [(3)]	**(55)**	**(58)**	(53)	(56)

(1) In August 2015 the Corporation settled expropriation matters with the Government of Belize ("GOB") regarding the GOB's expropriation of Belize Electricity (Note 21).
(2) The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $832 million (December 31, 2014 - $1,096 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.
(3) Included in long-term other liabilities on the consolidated balance sheet

18. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Financial Instruments Not Carried At Fair Value (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) 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.

19. 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.

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, 2015, FortisAlberta's gross credit risk exposure was approximately $112 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

19. 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 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 used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from 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, 2015, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $200 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at September 30, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.3 billion, of which approximately $2.0 billion was unused, including $273 million unused under the Corporation's 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 $3.1 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

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

				As at	
($ millions)	**Regulated Utilities**	**Non-Regulated**	**Corporate and Other**	**September 30, 2015**	December 31, 2014
Total credit facilities [1]	**2,013**	**13**	**1,297**	**3,323**	3,854
Credit facilities utilized:					
Short-term borrowings [2]	**(397)**	**-**	**-**	**(397)**	(330)
Long-term debt (Note 8) [3]	**-**	**-**	**(832)**	**(832)**	(1,096)
Letters of credit outstanding	**(71)**	**-**	**(34)**	**(105)**	(192)
Credit facilities unused	**1,545**	**13**	**431**	**1,989**	2,236

(1) Total credit facilities exclude a $300 million increase to the Corporation's committed corporate credit facility in March 2015, as discussed below.

(2) The weighted average interest rate on short-term borrowings was approximately 0.8% as at September 30, 2015 (December 31, 2014 - 1.3%).

(3) As at September 30, 2015, credit facility borrowings classified as long-term debt included $230 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 - $257 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.4% as at September 30, 2015 (December 31, 2014 - 1.8%).

19. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at September 30, 2015 and December 31, 2014, 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.

The significant changes in available credit facilities from that disclosed in the Corporation's 2014 annual audited consolidated financial statements are as follows.

In March 2015 the Corporation amended its $1 billion corporate committed credit facility, resulting in the ability to increase the facility to $1.3 billion and an extension of the maturity date to July 2020 from July 2018. As at September 30, 2015, the Corporation has not yet exercised its option for the additional $300 million.

In March 2015 TEP repaid its US$130 million non-revolving term loan commitment using net proceeds from the issuance of long-term debt. In June 2015 TEP terminated the associated credit agreement, which also included US$70 million in unsecured committed revolving credit facilities.

In April 2015 FortisBC Electric amended its $150 million unsecured committed revolving credit facility to now mature in May 2018.

In June 2015 FortisOntario amended its $30 million unsecured committed revolving credit facility to now mature in June 2016.

In July 2015 FortisAlberta renegotiated and amended its $250 million unsecured committed revolving credit facility, extending the maturity date to August 2020 from August 2019.

In July 2015 CH Energy Group amended its US$100 million committed credit facility, resulting in a decrease in the facility to US$50 million and an extension of the maturity date to July 2020 from October 2015. In October 2015 Central Hudson entered into a US$200 million unsecured committed revolving credit facility maturing in October 2020, replacing its previous US$150 million credit facility.

In July 2015 the Corporation repaid its $273 million medium-term bridge facility using net proceeds from the sale of commercial real estate assets (Note 7).

In August 2015 Fortis Turks and Caicos amended its US$26 million unsecured demand credit facilities to now mature in September 2016.

In August 2015 FortisBC Energy amended its $500 million credit facility, resulting in an increase in the facility to $700 million and an extension of the maturity date to August 2018 from August 2016, and cancelled its $200 million credit facility due to mature in December 2015.

In September 2015 TEP terminated its US$82 million letter of credit facility. In October 2015 TEP, UNS Electric and UNS Gas entered into unsecured committed revolving credit facilities totalling US$350 million maturing in October 2020, replacing their previous US$300 million credit facilities. In addition, UNS Energy Corporation entered into a US$150 million unsecured committed revolving credit facility maturing in October 2020, replacing its previous US$125 million facility. The new credit facility agreements allow for two one-year extensions.

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, 2015, the Corporation's credit ratings were as follows:

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

19. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In April 2015 S&P confirmed the Corporation's credit rating with a Stable outlook.

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 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 gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and Belize Electric Company Limited is the US dollar.

As at September 30, 2015, the Corporation's corporately issued US$1,597 million (December 31, 2014 - US$1,496 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at September 30, 2015, the Corporation had approximately US$3,092 million (December 31, 2014 - US$2,762 million) in foreign net investments remaining to be hedged. 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 on the consolidated balance sheet in accumulated 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 on the consolidated balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CDN$1.33 as at September 30, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk
The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

Commodity Price Risk
UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity. These derivative instruments 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 (Note 18).

20. COMMITMENTS

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2014 annual audited consolidated financial statements, except as follows.

UNS Energy is party to renewable power purchase agreements totalling approximately US$1,162 million as at September 30, 2015, which require UNS Energy to purchase 100% of certain renewable energy generation facilities that have achieved commercial operation. In September 2015 one of the facilities achieved commercial operation, increasing estimated future payments of renewable power purchase contracts by US$315 million as at September 30, 2015.

In March 2015 Maritime Electric extended its power purchase agreement with New Brunswick Power from March 2016 to February 2019, increasing the total commitment under this agreement by approximately $172 million as at September 30, 2015.

FortisBC Energy has entered into an Electricity Supply Agreement with BC Hydro for the purchase of electrical service to the Tilbury Expansion Project, with obligations totalling approximately $548 million as at September 30, 2015.

21. SETTLEMENT OF EXPROPRIATED ASSETS

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in the third quarter (Note 13).

22. 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 adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingencies.

UNS Energy
Springerville Unit 1
In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with the Federal Energy Regulatory Commission ("FERC"), alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action and in October 2015 FERC denied this request.

22. CONTINGENCIES (cont'd)

UNS Energy (cont'd)

Springerville Unit 1 (cont'd)

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to Wilmington Trust Company, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the third-party owners' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the third-party owners to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 by October 22, 2015, and ordering that they timely pay their share of all future Springerville Unit 1 expenses and expenditures during the pendency of the arbitration. Any amounts collected could be subject to refund if the arbitration panel subsequently upholds all or portions of the third-party owners' claims. The arbitration panel denied the third-party owners' motion for interim relief which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. On October 20, 2015, the third-party owners informed the arbitration panel that the owner trustees have no available funds and are unable to make the payments required by the interim order, and requested that the panel reconsider its associated decision in the interim order. In a letter dated October 27, 2015, the arbitration panel indicated that it reconsidered its decision and declined to change it. The arbitration hearing is scheduled for July 2016.

On October 30, 2015, TEP filed a petition to confirm the interim arbitration order in the U.S. District Court for the Southern District of New York naming the third-party owners as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act.

As at September 30, 2015, TEP billed the third-party owners approximately US$17 million for their pro-rata share of Springerville Unit 1 expenses and US$2 million for their pro-rata share of capital expenditures, none of which had been paid as of November 5, 2015.

Under the Springerville Unit 1 facility support agreement, TEP is permitted to dispatch and use any of the third-party owners' unscheduled entitlement share of power from Springerville Unit 1. TEP commenced such dispatch and use for TEP's benefit in June 2015.

22. CONTINGENCIES (cont'd)

UNS Energy (cont'd)

Springerville Unit 1 (cont'd)

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

San Juan Generating Station

San Juan Coal Company ("SJCC") operates an underground coal mine in an area where certain gas producers have oil and gas leases with the Government of the United States, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. The Company cannot reasonably estimate the impact of any future claims by these gas producers and, accordingly, no amount has been accrued in the consolidated financial statements.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. Upon expiration of the coal supply agreements, which expire between 2017 and 2031, TEP's share of reclamation costs at all three mines is expected to be US$37 million in total. The mine reclamation liability recorded as at September 30, 2015 was US$24 million (December 31, 2014 - US$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset (Note 5).

Central Hudson

Site Investigation and Remediation Program

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 1800s, with all sites ceasing operations by the 1950s. 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, 2015, an obligation of US$104 million was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

22. CONTINGENCIES (cont'd)

Central Hudson (cont'd)

Site Investigation and Remediation Program (cont'd)

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, 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. In the three-year Rate Order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018 (Note 5).

Asbestos Litigation

Prior to and after the acquisition of CH Energy Group, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,168 remained pending as at September 30, 2015. Of the cases no longer pending against Central Hudson, 2,026 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding 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 consolidated financial statements.

FortisBC Electric

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 include 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 notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis

Following the announcement of the acquisition of UNS Energy on December 11, 2013, four complaints which named Fortis and other defendants were filed in the Superior Court of the State of Arizona ("Superior Court") in and for the County of Pima and one claim in the United States District Court in and for the District of Arizona, challenging the acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the acquisition and that UNS Energy, Fortis, FortisUS Inc., and Color Acquisition Sub Inc. aided and abetted that breach. In March 2014 two of the four complaints filed in the Superior Court were dismissed by the plaintiffs and counsel for the parties in the two actions remaining in the Superior Court executed a Memorandum of Understanding recording an agreement-in-principle on the structure of a settlement to be proposed to the Superior Court for approval following closing of the acquisition. In April 2014 the complaint filed in the United States District Court was dismissed by the plaintiff, and in August 2015 the case was settled for less than $1 million.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. 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 consolidated financial statements.

23. SUBSEQUENT EVENT

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As at September 30, 2015, the associated assets have been classified as held for sale on the consolidated balance sheet (Note 6). Net proceeds from the sale were used by the Corporation to repay credit facility borrowings and for other general corporate purposes.

24. COMPARATIVE FIGURES

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

Expected Dividend* and Earnings Dates

Earnings Release Dates

February 18, 2016	May 3, 2016
July 29, 2016	November 4, 2016

Dividend Record Dates

November 18, 2015	February 17, 2016
May 18, 2016	August 19, 2016

Dividend Payment Dates

December 1, 2015	March 1, 2016
June 1, 2016	September 1, 2016

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Registrar and Transfer Agent

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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 I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M 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.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively.

Fortis Common Shares ($) Quarter Ended September 30		
	2015	**2014**
High	**38.75**	**34.81**
Low	**34.16**	**32.14**
Close	**38.17**	**34.62**

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