Fortis Inc. 2012 Annual Report

FORTIS INC.

2012 ANNUAL REPORT

Operations

Regulated Utility Operations

Gas Operations

FortisBC *British Columbia*
Central Hudson* *New York State*

Electric Operations

FortisAlberta *Alberta*
FortisBC *British Columbia*
Newfoundland Power *Newfoundland*
Maritime Electric *Prince Edward Island*
FortisOntario *Ontario*
Caribbean Utilities *Grand Cayman*
Fortis Turks and Caicos *Turks and Caicos Islands*
Central Hudson* *New York State*

Non-Regulated Operations

Fortis Generation

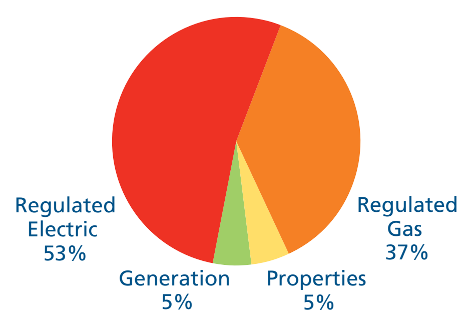
Locations
Belize, Ontario, central Newfoundland, British Columbia, New York State

Fortis Properties

Real Estate and Hotels
Across Canada

Total Assets $15 Billion

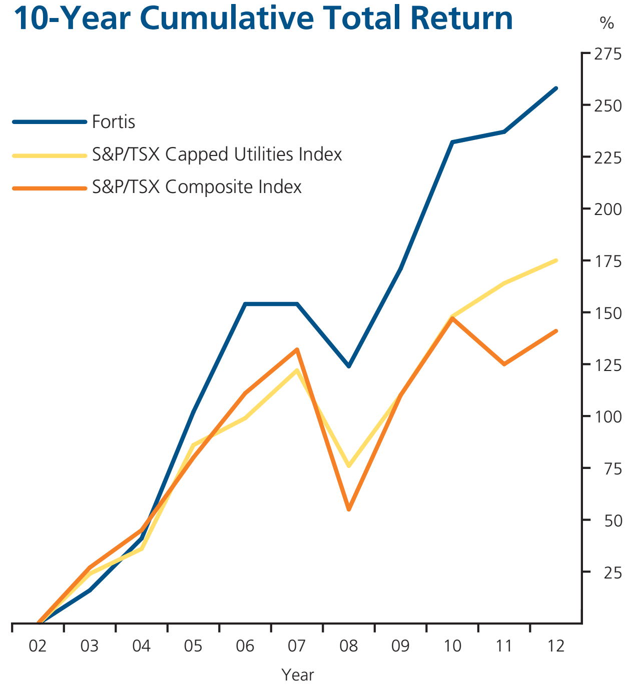
(as at December 31, 2012)



* Pending acquisition of CH Energy Group, Inc.

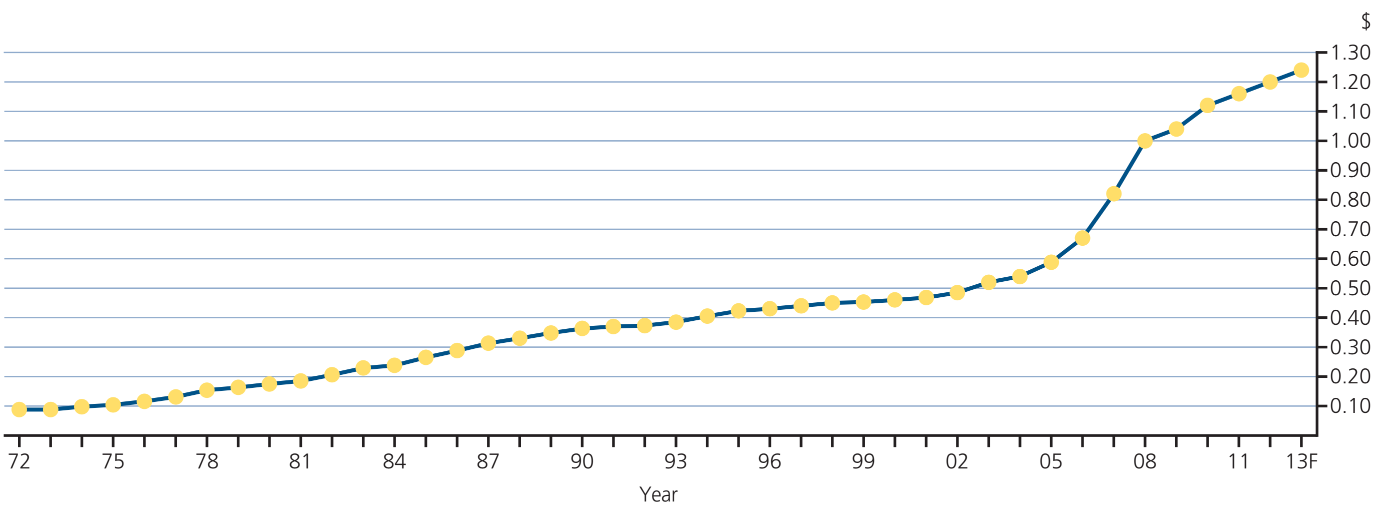
Contents

10-Year Cumulative Total Return



Dividends paid per common share

Fortis has increased its annualized dividend to common shareholders for 40 consecutive years, the longest record of any public corporation in Canada.



The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

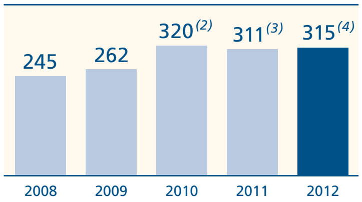
i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

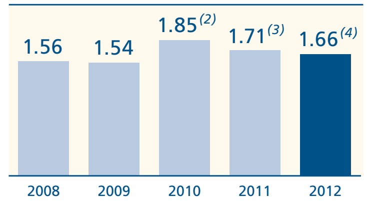
iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

Investor Highlights[1]

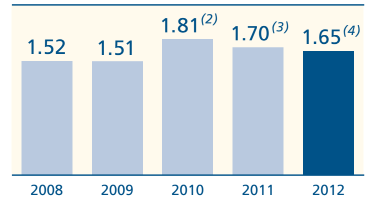
Earnings Attributable to Common Equity Shareholders ($M)



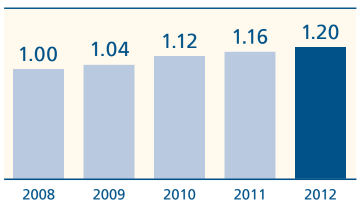
Basic Earnings per Common Share ($)



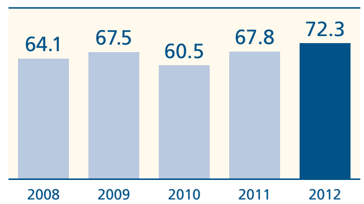
Diluted Earnings per Common Share ($)



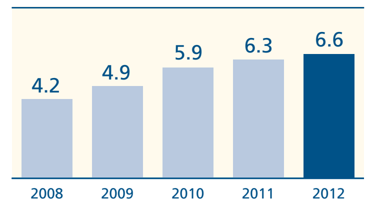
Dividends Paid per Common Share ($)



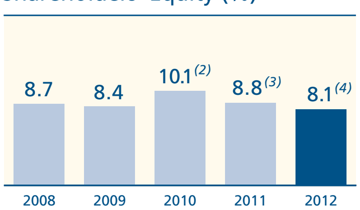
Dividend Payout Ratio (%)



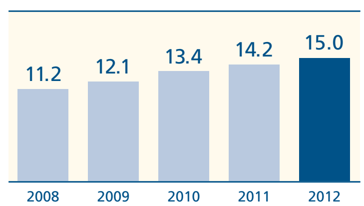
Market Capitalization ($B)



Return on Average Book Common Shareholders' Equity (%)

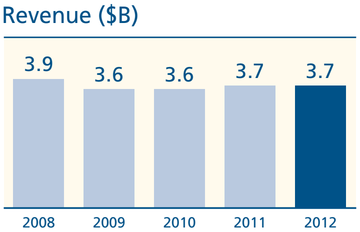


Assets ($B)

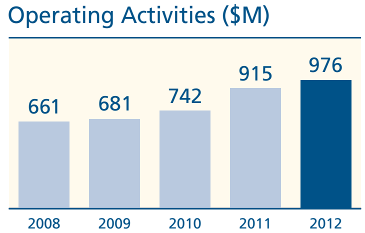


Capital Expenditures ($B)

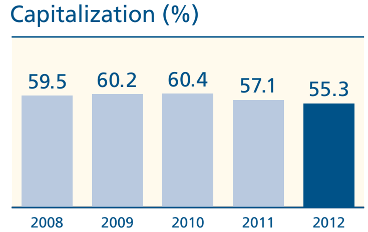
Revenue ($B)



Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



(1) *Financial information for the years 2010 through 2012 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP*

(2) *Includes the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with other post-employment benefits upon adoption of US GAAP*

(3) *Includes the $11 million favourable impact to earnings of a merger termination fee paid to Fortis in July 2011*

(4) *Includes the $7.5 million unfavourable impact to earnings of acquisition-related expenses associated with the pending acquisition of CH Energy Group, Inc.*

All financial information is presented in Canadian dollars.

Information is for the fiscal years ended December 31.

Regulated

Gas

FortisBC [1]	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) [2]	Earnings ($M)	Allowed ROE (%) [3] 2012	Allowed ROE (%) [3] 2013
Total	**945,000**	**1,681**	**1,336**	**199**	**206**	**5.5**	**3.7**	**138**	**9.50**	**9.50 [4]**

Electric

	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) [2]	Earnings ($M)	Allowed ROE (%) [3] 2012	Allowed ROE (%) [3] 2013
FortisAlberta	508,000	1,107	2,652	16,799	442	3.0	2.3	96	8.75	8.75 [4]
FortisBC	163,000	542	737	3,143	69	1.9	1.2	50	9.90	9.90 [4]
Newfoundland Power	251,000	653	1,241	5,652	86	1.4	0.9	37	8.80	8.80 [4]
Maritime Electric	76,000	178	230	1,079	25	0.5	0.3	13	9.75	9.75
FortisOntario	64,000	196	253	1,302	23	0.3	0.2	11	8.01/9.85 [5]	8.93/9.85 [5]
Caribbean Utilities [6]	27,000	190	96	548	30	0.5	0.4	10	7.25–9.25 [7]	7.25–9.25 [7] [8]
Fortis Turks and Caicos [9]	12,000	151	35	180	18	0.3	0.2	9	17.50 [7] [10]	17.50 [7] [10]
Total	**1,101,000**	**3,017**	**5,244**	**28,703**	**693**	**7.9 [11]**	**5.5**	**226**		

[1] Includes the operations of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., collectively known as the "FortisBC Energy companies"

[2] Forecast midyear 2013

[3] Rate of return on common shareholders' equity ("ROE"). For the gas segment, ROE is for FortisBC Energy Inc. ROE for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. is 50 basis points higher.

[4] Interim and subject to change based on the outcomes in 2013 of cost of capital proceedings

[5] 2012 – Canadian Niagara Power 8.01%; Algoma Power 9.85%; 2013 – Canadian Niagara Power 8.93%; Algoma Power 9.85%

[6] Information in table represents 100% of Caribbean Utilities' operations except for earnings data. Earnings represent Caribbean Utilities' contribution to consolidated earnings of Fortis, based on the Corporation's approximate 60% ownership interest.

[7] Regulated rate of return on rate base assets ("ROA")

[8] Subject to change in June 2013 based on the annual operation of the rate-cap adjustment mechanism

[9] Comprised of FortisTCI Limited ("FortisTCI"), Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") and, as of August 2012, Turks and Caicos Utilities Limited ("TCU"), collectively known as "Fortis Turks and Caicos"

[10] Amount provided under licence is for FortisTCI and Atlantic. Amount provided under licence for TCU is 15%. Combined ROA achieved in 2012 was 7%.

[11] Plus $104 million associated with the net book value of the Corporation's expropriated investment in Belize Electricity

Non-Regulated

Fortis Generation [1]

	Generating Capacity (MW)	Energy Sales (GWh)	Total Assets ($B) [3]	Earnings ($M)	Capital Program ($M) [4]
Total	**139**	**306**	**0.8**	**17**	**196**

Fortis Properties [2]

	Employees (#)	Total Assets ($B)	Earnings ($M)	Capital Program ($M)
Total	**2,400**	**0.7**	**22**	**35**

[1] Comprised of investments in Belize, Ontario, central Newfoundland, British Columbia and Upstate New York

[2] Includes approximately 2.7 million square feet of commercial office and retail space, primarily in Atlantic Canada, and 23 hotels across Canada

[3] Includes $65 million in "Other" non-regulated assets

[4] Includes $192 million related to the construction of the Waneta Expansion hydroelectric generating facility in British Columbia

Information is for the fiscal year ended December 31, 2012 unless otherwise indicated.

Report to Shareholders

Stan Marshall
President and CEO, Fortis Inc.

David Norris
Chair of the Board, Fortis Inc.

Dear Shareholder,

Your company continues to grow strategically and profitably, while we remain focused on our customers' requirements for service of high quality and value.

Fortis has grown dramatically over the last decade, driven by the acquisition of regulated utilities in western Canada and ongoing capital investments. The compound annual growth rate of our assets for the 10 years ended December 31, 2012 was 23%.

For the fourth consecutive year, our capital program surpassed $1 billion. Fortis utilities collectively serve more than two million customers and our substantial capital investments, the majority of which is occurring in western Canada, will ensure we continue to meet the growing energy needs of our existing and new customers.

During the past year, we made significant progress in our strategy to expand into the U.S. utility marketplace. In February 2012 Fortis entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. Central Hudson Gas & Electric Corporation ("Central Hudson"), the main business of CH Energy Group, serves 375,000 electric and gas customers in New York State's Mid-Hudson River Valley. The utility's capital program over the next five years is expected to average more than $125 million annually. The acquisition is expected to be accretive to earnings per common share of Fortis within the first full year of ownership, excluding acquisition-related expenses.

Approval of the acquisition by the New York State Public Service Commission ("NYSPSC") is the last significant regulatory matter required to close the transaction. A Settlement Agreement among Fortis, CH Energy Group, NYSPSC staff, registered interveners and other parties was filed with the NYSPSC in January 2013. The acquisition is expected to close during the second quarter of 2013.

Earnings at our Canadian Regulated Utilities increased approximately 11% year over year, led by strong growth at FortisAlberta.

Fortis achieved net earnings attributable to common equity shareholders of $315 million, or $1.66 per common share, for 2012 compared to $311 million, or $1.71 per common share, for 2011.

Earnings in 2012 were reduced by $7.5 million as a result of expenses related to the CH Energy Group acquisition, while earnings in 2011 were favourably impacted by a one-time $11 million merger termination fee paid to Fortis. Excluding these items, earnings to common equity shareholders were up $22.5 million, or $0.05 per common share, from 2011, highlighted by improved performance at the Canadian Regulated Utilities. A 5% increase in the weighted average number of common shares outstanding year over year, largely associated with the issuance of common equity in mid-2011, tempered earnings per common share in 2012.

Fortis increased its quarterly common share dividend to 31 cents, commencing with the first quarter dividend paid in 2013, which translates into an annualized dividend of $1.24. Fortis has increased its annualized dividend to common shareholders for 40 consecutive years, the record for a public corporation in Canada. Dividends paid per common share have increased at a compound annual growth rate of 9.5% over the past 10 years. The dividend payout ratio was 72% in 2012.

In 2012 Fortis delivered a total return to shareholders of approximately 6% compared to the annualized performance provided by the S&P/TSX Composite and S&P/TSX Capped Utilities Indices of approximately 7% and 4%, respectively. Over the past 10 years, Fortis delivered an annualized total return of approximately 14%, outperforming both the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which, over the same period, provided annualized performance of approximately 11% and 9%, respectively.

Our 2012 capital program totalled $1.13 billion. At FortisBC Gas, the Customer Care Enhancement Project, including two new customer care centres, came into service at the beginning of 2012. Our largest capital project currently underway, the non-regulated $900 million, 335-megawatt Waneta Expansion hydroelectric generating facility ("Waneta Expansion") on the Pend d'Oreille River in British Columbia, continues on time and on budget. Excavation of the intake, powerhouse and power tunnels was completed during the year. Approximately $436 million in total has been spent on the Waneta Expansion since construction began in late 2010, with a further $227 million expected to be spent in 2013. Fortis owns 51% of the Waneta Expansion and will operate and maintain the facility when it comes online, which is expected to be in spring 2015.

Canadian Regulated Utilities contributed earnings of $345 million, $34 million higher than earnings of $311 million for 2011.

Earnings at Canadian Regulated Electric Utilities were up $33 million from 2011. FortisAlberta's earnings increased $22 million, mainly related to growth in energy infrastructure investment and net transmission revenue of $8.5 million recognized in 2012. The utility invested more than $400 million in capital projects in 2012 and is expected to invest a comparable amount in 2013. Newfoundland Power's earnings were $5 million higher year over year, largely due to lower effective income taxes. FortisBC Electric's earnings increased $2 million as a result of growth in energy infrastructure investment, higher pole-attachment revenue and lower-than-expected finance charges in 2012, partially offset by the discontinuance of the performance-based rate-setting ("PBR") mechanism on December 31, 2011. Improved earnings of $4 million at the Corporation's Other Canadian Regulated Electric Utilities were mainly due to lower effective income taxes at Maritime Electric and the cumulative return earned on capital investment in smart meters at FortisOntario.

Canadian Regulated Gas Utilities delivered earnings of $138 million, up $1 million from 2011. Growth in energy infrastructure investment, higher gas transportation volumes to industrial customers, lower-than-expected operating expenses in 2012 and lower effective income taxes were partially offset by lower-than-expected customer additions in 2012 and lower capitalized allowance for funds used during construction.

The regulatory calendar at our Canadian utilities was very busy in 2012 and remains so for 2013. FortisBC received regulatory decisions in 2012 for 2012/2013 revenue requirements at its gas and electric utilities and expects to file its next rate applications in the first half of 2013. FortisAlberta received a decision in April 2012 on its 2012 revenue requirements. The Alberta Utilities Commission ("AUC") issued a generic decision in September 2012 on its PBR Initiative, outlining the PBR framework applicable to distribution utilities in Alberta for a five-year term, which commenced January 1, 2013. The Alberta PBR decision raises concerns for FortisAlberta regarding the treatment of certain capital expenditures. FortisAlberta along with other distribution utilities operating in Alberta have requested leave to appeal the PBR decision to the Alberta Court of Appeal. In March 2013 the regulator issued an interim decision on FortisAlberta's Compliance Application approving a 1.71% increase in customer distribution rates and 60% of the revenue requirement associated with the utility's 2013 Capital Tracker Application, effective January 1, 2013. Final decisions on the Compliance and Capital Tracker Applications are expected later in 2013.

Final allowed rates of return on common shareholders' equity and capital structure for 2013 remain to be determined for FortisBC, FortisAlberta and Newfoundland Power. In Alberta, an AUC-initiated Generic Cost of Capital ("GCOC") Proceeding is expected to commence later in 2013. In British Columbia, a public hearing occurred in December 2012 related to the first phase of a GCOC Proceeding initiated by the regulator in 2012. At Newfoundland Power, a public hearing concluded in February 2013 on the utility's general rate application filed in September 2012 to determine 2013/2014 customer rates and cost of capital. Notwithstanding the significant proceedings in 2013, we expect continued regulatory stability.

Caribbean Regulated Electric Utilities contributed $19 million of earnings compared to $20 million for 2011. FortisTCI Limited acquired Turks and Caicos Utilities Limited in August 2012 for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of assumed debt.

Fortis continues to challenge the constitutionality of the Government of Belize's expropriation of Belize Electricity and has a strong, well-positioned case before the Belize Courts. In June 2011 the Government of Belize enacted legislation expropriating the Corporation's 70% controlling ownership investment in the utility. At December 31, 2012, the book value of the expropriated investment was $104 million.

Non-Regulated Fortis Generation contributed $17 million of earnings compared to $18 million for 2011. The decrease in earnings was mainly due to overall lower production associated with less rainfall and a small generating facility being out of service in 2012.

Fortis Properties delivered earnings of $22 million compared to $23 million for 2011. The Company's hotel operations are being impacted by the continuing slow economic recovery in the Ontario marketplace. Fortis Properties acquired the 126-room StationPark All Suite Hotel in London, Ontario for approximately $13 million, inclusive of debt assumed, in October 2012.

Corporate and other expenses were $88 million compared to $61 million for 2011. Excluding CH Energy Group acquisition-related expenses, incurred largely in the first half of 2012, and the merger termination fee paid to Fortis in July 2011, corporate and other expenses were $8.5 million higher year over year. The increase was mainly the result of foreign exchange impacts, certain non-recurring operating expenses in 2012 and lower effective income tax recoveries, partially offset by lower finance charges.

Report to Shareholders

Fortis is one of the highest-rated utility holding companies in North America with its corporate debt rated A- by Standard & Poor's and A(low) by DBRS, unchanged from 2011. The credit ratings were affirmed in 2012, reflecting several factors, notably the diversity of the Corporation's utility asset mix, as well as its financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget.

Fortis has consolidated credit facilities of approximately $2.5 billion, of which $2.1 billion was unused as at December 31, 2012. Approximately $2.3 billion of the total credit facilities are committed facilities, having maturities ranging from 2013 through 2017. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. As at December 31, 2012, the Corporation's long-term debt repayments and maturities are expected to average approximately $273 million annually over the next five years.

Strong investment grade credit ratings, ample credit facilities and low debt maturities provide flexibility in the timing of access to the debt and equity capital markets. Fortis raised gross proceeds of approximately $601 million, upon issuance of 18.5 million Subscription Receipts at $32.50 each in June 2012, to finance a portion of the purchase price of CH Energy Group. The proceeds are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, contained in the agreement to acquire CH Energy Group. Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the closing conditions, one common share of Fortis. The Corporation issued $200 million 4.75% preference shares in November 2012 to repay borrowings under its committed corporate credit facility and FortisAlberta raised $125 million 40-year 3.98% unsecured debentures, largely in support of its capital expenditure program, in October 2012.

With the acquisition of CH Energy Group, the Corporation's regulated midyear rate base will increase to approximately $10 billion. The regulated assets and earnings of Fortis will be further diversified by geographic location and regulatory jurisdiction, thereby helping to reduce business risk.

CH Energy Group will continue to operate with substantial autonomy as a Fortis utility and its headquarters and management team will remain in Poughkeepsie, New York. We look forward to welcoming the employees of CH Energy Group to the Fortis Group. The addition of this well-run U.S. utility and its proven track record for providing customers with quality service will further enhance the positioning of Fortis as a leader in the North American utility industry.

We extend thanks and appreciation to our employees, some 7,200 strong, whose hard work and commitment to customers underpins the success of our organization. We also acknowledge the oversight and support provided by our Board of Directors.

Fortis is well positioned for growth in 2013 and beyond. Execution of our $1.3 billion capital program for 2013 is progressing well. Capital investment will support continuing growth in earnings and dividends and will be mostly funded with cash from operations and long-term debt at the regulated utility level.

Over the five years 2013 through 2017, the Corporation's capital program, including expenditures at Central Hudson, is expected to total approximately $6 billion. Capital investment over that period is expected to allow utility rate base and hydroelectric generation investment to increase at a combined compound annual growth rate of approximately 6%.

On behalf of the Board of Directors,

David G. Norris
Chair of the Board
Fortis Inc.

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

Management Discussion and Analysis

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Dated March 20, 2013

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*. Financial information for 2012 and comparative periods 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. The MD&A should be read in conjunction with the following: (i) the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2012 prepared in accordance with US GAAP and included in the Corporation's 2012 Annual Report; and (ii) the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2011, prepared in accordance with US GAAP and voluntarily filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") by Fortis on March 16, 2012, which provide a detailed reconciliation between the Corporation's audited consolidated 2011 financial statements prepared in accordance with Canadian GAAP and audited consolidated 2011 financial statements prepared in accordance with US GAAP.

Barry Perry, VP, Finance and CFO, Fortis Inc.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", *"forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the principal business of Fortis remaining the ownership and operation of regulated electric and gas utilities; the Corporation's primary focus on the United States in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030 to maintain system reliability; the expected timing of the closing of the acquisition of CH Energy Group, Inc. ("CH Energy Group") by Fortis and the expectation that the acquisition will be accretive to earnings per common share of Fortis within the first full year of ownership, excluding acquisition-related expenses; the Corporation's expected regulated midyear rate base in 2013 upon closing of the CH Energy Group acquisition; forecasted 2013 midyear rate base for the Corporation's four large regulated utilities and Central Hudson Gas & Electric Corporation ("Central Hudson"); the Corporation's consolidated forecasted gross capital expenditures for 2013 and in total over the five years 2013 through 2017 and average annual capital expenditures at Central Hudson over the same time period; the expected combined compound annual growth rate of utility rate base and hydroelectric generation investment over the next five years; the expectation that FortisAlberta's load and rate base will be positively impacted as a result of continuing economic growth in Alberta; various natural gas and electricity transmission investment opportunities that may be available to the Corporation; an expected favourable impact on the Corporation's earnings in future periods upon final enactment of legislative changes to Part VI.1 taxes; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; there is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; 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 2013 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2013 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium 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; except for debt at the Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2013; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2013; the expected impact on 2013 earnings for each of the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power of changes in the allowed rate of return on common shareholders' equity ("ROE") and common equity component of total capital structure; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on annual basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2013; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; and the expectation that consolidated defined benefit net pension cost for 2013 will be comparable to that in 2012 and that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future.*

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received and the expectation of regulatory stability; FortisAlberta continues to recover its cost of service and earn its allowed ROE under performance-based rate-setting ("PBR"), which commenced for a five-year term effective January 1, 2013; the receipt of regulatory approval from the New York State Public Service Commission of a settlement agreement, as filed, pertaining to the acquisition of CH Energy Group; the closing of the acquisition of CH Energy Group before the expiry of the Subscription Receipts on June 30, 2013; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under accounting principles generally accepted in the United States beyond 2014 or the adoption of International Financial Reporting Standards after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2013 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at each of the Corporation's four large Canadian regulated utilities; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risks relating to the ability to close the acquisition of CH Energy Group, the timing of such closing and the realization of the anticipated benefits of the acquisition; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

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

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than two million gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upstate New York, and hotels and commercial office and retail space in Canada. In 2012 the Corporation's electricity distribution systems met a combined peak demand of 5,244 megawatts ("MW") and its gas distribution system met a peak day demand of 1,336 terajoules.

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

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

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets have a combined generating capacity of 139 MW, which is mainly hydroelectric. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return. Income from non-regulated investments is used to help offset corporate holding company expenses, a large part of which is interest expense associated with debt incurred to finance a portion of the premiums paid on the acquisitions of regulated utilities.

The business segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates autonomously, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities: The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean are as follows:

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI").

FEI is the largest distributor of natural gas in British Columbia, serving approximately 841,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves approximately 101,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia, which provides service to approximately 3,000 customers.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 508,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 163,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC Electric component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 251,000 customers. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Comprised of Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 76,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company has an installed diesel-powered generating capacity of 150 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2011 – 60%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Comprised of FortisTCI Limited ("FortisTCI"), Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") and Turks and Caicos Utilities Limited ("TCU"), which was acquired in August 2012, (collectively "Fortis Turks and Caicos"). Each of the Fortis Turks and Caicos utilities is an integrated electric utility and, combined, serve approximately 12,000 customers and have a diesel-powered generating capacity of 76 MW. Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through FortisTCI and to South Caicos through Atlantic. Fortis Turks and Caicos also provides electricity to Grand Turk and Salt Cay through TCU.

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c. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. Fortis held an approximate 70% controlling ownership interest in Belize Electricity up to June 20, 2011. As of June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information, refer to the "Key Trends, Risks and Opportunities – Expropriated Assets" and "Business Risk Management – Expropriation of Shares in Belize Electricity" sections of this MD&A.

Non-Regulated – Fortis Generation: The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Comprised of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Comprised of six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall. Effective July 1, 2012, the legal ownership of the hydroelectric generating facilities in eastern Ontario was transferred from Fortis Properties to Fortis Generation East LLP, a limited liability partnership directly held by Fortis.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Fortis Properties holds directly a 51% interest in the Exploits Partnership and Abitibi holds the remaining 49% interest. Output from the generating facilities is being sold to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement ("PPA") expiring in 2033. In December 2008 the Government of Newfoundland and Labrador expropriated the hydroelectric assets and water rights of the Exploits Partnership. As a result of no longer controlling the cash flows and operations of the Exploits Partnership, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership effective February 2009. For further information, refer to the "Key Trends, Risks and Opportunities – Expropriated Assets" section of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract set to expire in the fourth quarter of 2013. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, in late 2010. The Waneta Expansion is expected to come into service in spring 2015.

e. *Upstate New York:* Comprised of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upstate New York, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

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

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 finance charges, comprised of interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI"); dividends on preference shares; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and related income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP") and FortisBC Alternative Energy Services Inc. ("FAES"). CWLP is a non-regulated shared-services business in which FHI holds a 30% interest. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011. CWLP's financial results were recorded using the equity method of accounting. FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE VISION AND STRATEGY

The principal business of Fortis is and will remain the ownership and operation of regulated gas and electric utilities, with a vision to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders. The key goals of the Corporation's regulated utilities are to operate sound electricity and gas distribution systems; deliver safe, reliable, cost-efficient energy to customers; and conduct business in an environmentally responsible manner.

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. Over the 10-year period ending December 31, 2012, earnings per common share of Fortis have grown at a compound annual growth rate of 5.5%. Fortis delivered an annualized total return to shareholders of approximately 14% over the past 10 years, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered annualized performance of approximately 11% and 9%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Fortis also pursues opportunities to acquire additional regulated utilities in the United States and Canada. The primary focus will be utilities in the United States because there are limited opportunities available in Canada to acquire additional regulated electric and gas utilities. The U.S. marketplace provides significantly more acquisition targets. U.S. utility acquisitions will help diversify the regulated assets, earnings and cash flows of Fortis by geographic region, further reducing business risks associated with the Corporation's regulated operations and will establish a broader foundation for the Corporation to continue to grow its earnings.

The acquisition of the FortisBC Energy companies in May 2007, which almost doubled the size of the Corporation's assets at that time, has provided Fortis a platform to acquire larger-sized regulated utilities. The FortisBC Energy companies have also improved the risk profile, credit support and cash flows of Fortis by providing the Corporation with a more economically diverse portfolio of assets. The pending acquisition of CH Energy Group, Inc. ("CH Energy Group") has similar characteristics, but to a lesser extent given its smaller size.

For further information on the pending acquisition of CH Energy Group, refer to the "Key Trends, Risks and Opportunities – Initial Entry into the Regulated U.S. Utility Market", "Significant Items – Pending Acquisition of CH Energy Group" and "Business Risk Management – Completion of the Acquisition of CH Energy Group" sections of this MD&A.

Fortis has built a base of non-regulated and international investments that provide financial, tax and regulatory flexibility. Fortis will pursue opportunities to continue to grow its non-regulated hydroelectric, hotel and real estate assets in support of its utility growth strategy. Once completed in spring 2015, the 335-MW Waneta Expansion is expected to increase earnings from the Non-Regulated – Fortis Generation segment by 150% above the 2012 earnings level. Fortis Properties acquired the 126-room StationPark All Suite Hotel ("StationPark Hotel") in London, Ontario for $13 million, inclusive of debt assumed, in October 2012 and purchased the 159-room, full-service Hilton Suites Winnipeg Airport hotel ("Hilton Suites Hotel") for approximately $25 million in October 2011.

KEY TRENDS, RISKS AND OPPORTUNITIES

General Trends for the Energy Sector: Traditional goals of safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of key issues impacting the energy industry. Evolving and more global issues include climate change, national issues pertaining to security, the development of expanded natural gas resources as a source of energy supply, the increasing deployment of alternative energy resources, as well as a growing desire by customers to have greater control over their energy use to lower costs and decrease their environmental footprint.

According to the National Energy Board's current energy market assessment report, *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, energy supply in Canada is expected to grow to record levels by 2030 as a result of unconventional production, including the application of multi-stage hydraulic fracturing in tight oil plays. While energy from fossil fuels remains the dominant source of supply, various programs and policies are expected to encourage emerging fuels and technologies to gain market share. Energy demand growth in the commercial and transportation sectors is expected to slow considerably from historical growth rates, which is anticipated to be offset by demand growth in the industrial sector to be led by the oil and gas industry. Over the next 20 years, Canada will need to invest $350 billion in its electricity infrastructure in order to maintain system reliability. Two-thirds of the investment will be to replace or renew aging generation assets, add to renewable generation capability and accommodate market growth. The remainder will be for transmission, expanding distribution and maintaining service quality.

Initial Entry into the Regulated U.S. Utility Market: Fortis is focused on closing the CH Energy Group transaction, which is expected to occur during the second quarter of 2013. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation ("Central Hudson"), is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley.

The pending acquisition of CH Energy Group establishes a platform for Fortis to build its U.S. regulated electric and gas utility assets and is attractive for the following reasons: (i) the acquisition is expected to be accretive to earnings per common share of Fortis within the first full year of ownership, excluding acquisition-related expenses; (ii) CH Energy Group has a strong balance sheet and Central Hudson has strong investment-grade credit ratings; (iii) Central Hudson, a single-state utility, operates a well-maintained electric and gas distribution system, serving a diversified, primarily residential and commercial customer base; (iv) similar to the electric distribution utilities of Fortis, Central Hudson operates principally under COS regulation; has earned stable returns; is allowed timely recovery of costs related to purchased electricity and natural gas supply, transmission and capital programs, including mechanisms to allow for full recovery of such costs; has deferral provisions for pension and other post-retirement benefit ("OPEB") expense and manufactured gas plant site remediation; and has revenue decoupling mechanisms; (v) Central Hudson's continued investment in its electric and gas businesses is expected to result in rate base growth; and (vi) the acquisition increases diversification of the Corporation's regulated assets and earnings by geographic location and regulatory jurisdiction.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is regulated by the regulatory body in its respective operating jurisdiction. In total the Corporation's utilities operate in seven different regulatory jurisdictions. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been satisfactory, with reasonably fair decisions reached in the past several years, with the exception of the June 2008 regulatory rate decision received by Belize Electricity. That decision ultimately led to the expropriation of the Corporation's investment in Belize Electricity by the GOB in June 2011. As at December 31, 2012, the book value of the Corporation's expropriated investment in Belize Electricity was $104 million, representing less than 1% of the total assets of Fortis.

Commitment by the Corporation's utilities to provide safe and reliable service, customer satisfaction and operational excellence and to promote positive customer and regulatory relations is important for supportive regulatory relationships and obtaining full cost recovery and competitive returns for the Corporation's shareholders.

A key regulatory change for the Corporation is the transition to PBR in Alberta for a five-year term that commenced January 1, 2013, which is the most significant shift in the operating environment for Alberta distribution utilities since deregulation. The transition to the use of a formula under PBR to establish customer rates raises some concern and uncertainty for FortisAlberta regarding how PBR will be applied in practice, including how certain capital expenditures will be recovered outside of the PBR formula.

The response of the Government of PEI to the recommendations in the public release of the *Final Report, Charting our Electricity Future* from the PEI Energy Commission ("PEI Commission") in January 2013 could reduce Maritime Electric's ownership of generation assets and resulting rate base, as well as impact how the utility is regulated going forward.

For a further discussion of regulatory risk and the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Business Risk Management – Regulatory Risk" and "Regulatory Highlights" sections of this MD&A.

Allowed Rates of Return on Common Shareholders' Equity: The table below highlights the allowed ROEs at each of the Corporation's four large Canadian regulated utilities since 2008.

Regulator-Approved Allowed ROEs

(%)	2008	2009	2010	2011	2012	2013 (1)
FEI	8.62	8.47/9.50	9.50	9.50	9.50	9.50
FortisAlberta	8.75	9.00	9.00	8.75	8.75	8.75
FortisBC Electric	9.02	8.87	9.90	9.90	9.90	9.90
Newfoundland Power	8.95	8.95	9.00	8.38	8.80	8.80

(1) Interim and subject to change based on the outcomes in 2013 of cost of capital proceedings in British Columbia, Alberta and Newfoundland

The allowed ROEs for 2013 for the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power are interim and subject to change based on the outcomes in 2013 of cost of capital proceedings in British Columbia, Alberta and Newfoundland. Uncertainty exists as to whether ROE automatic adjustment mechanisms will be re-established and what the final allowed ROEs and capital structures will be. Currently, the Corporation's four large Canadian regulated utilities do not use automatic adjustment mechanisms to annually set allowed ROEs. Uncertainty also exists regarding the duration of the current environment of low interest rates and what effect it may have on allowed ROEs of the Corporation's regulated utilities.

Capital Expenditure Program and Rate Base Growth: With the acquisition of CH Energy Group, the Corporation's regulated midyear rate base will increase to approximately $10 billion. Over the five years 2013 through 2017, the Corporation's consolidated capital expenditure program, including expenditures at Central Hudson, is expected to total $6 billion. Central Hudson's capital program over the next five years is expected to average more than $125 million annually. Capital investment should allow the Corporation's consolidated regulated midyear rate base, including incremental investment in rate base by Central Hudson, and investment in the non-regulated Waneta Expansion to increase at a combined compound annual growth rate of approximately 6% through 2017.

For further information on the Corporation's consolidated capital expenditure program and rate base of its four large Canadian regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Natural Gas Opportunities: As a result of technological advances in exploration and drilling, the amount of accessible natural gas in British Columbia has increased in recent years.

Traditionally, the majority of the natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas plays, additional capacity to connect to markets will have to be developed. FortisBC is exploring pipeline investment opportunities that include expansion of its existing distribution system to supply natural gas to a prospective liquefied natural gas ("LNG") export facility, as well as to expand capacity on its Southern Crossing transmission pipeline.

The combination of an abundant supply of natural gas, improved economics and more positive government policy may allow the creation of industrial developments that rely on the use of natural gas to emerge on the coast of British Columbia in the medium to long term. Opportunities may also exist for gas-fired electricity generation. The Government of British Columbia's *2012 Natural Gas Strategy* highlights the support for the export of natural gas through the development of LNG export facilities in Kitimat and Prince Rupert, British Columbia, which, in turn, should drive the need for significant generation and transmission investment.

The new regulation under the *Clean Energy Act* recently passed in British Columbia will enable FortisBC to advance the use of natural gas in the transportation sector, given the opportunity it provides to reduce greenhouse gas ("GHG") emissions. The economic benefits of using natural gas for transportation applications include cost savings for customers, contributions to the provincial economy through increased tax revenues and reduced costs for public services, schools and public transit as the result of fuel-cost savings.

Western Canadian Economies: A large proportion of the businesses of Fortis serve the economies of western Canada, where economic growth has generally been higher than the rest of the country. As at December 31, 2012, regulated utility assets comprised 90% of total assets (December 31, 2011 – 91%) and regulated utility assets in western Canada comprised 77% of total regulated assets (December 31, 2011 – 78%). FortisAlberta is the Corporation's fastest-growing utility in Canada. Since it was acquired in May 2004, the rate base of FortisAlberta has grown by 228%. The Alberta economy is expected to remain robust, buoyed by continued strength in the resource sector, especially crude oil extraction. FortisAlberta services some of the fastest-growing areas of Canada, with much of the utility's growth related to oil sands and shale oil developments and associated residential and commercial developments, predominantly in the communities surrounding the cities of Calgary and Edmonton. FortisAlberta's load and rate base are expected to be positively impacted as a result of this continuing economic growth.

Electricity Transmission Investment Opportunities: The Alberta Electric System Operator ("AESO") has been directed to develop a competitive procurement process to construct and operate certain major transmission facilities in Alberta. AESO has recommended a single-owner model for this competitive process, which would allow the successful bidder to construct, own and operate the facility. An opportunity may exist for possible investment by Fortis in the Edmonton-to-Fort McMurray Transmission Reinforcement Project, which is estimated to cost $1.6 billion. The submission date for request for expressions of interest and qualification for this project is estimated to be mid-2013.

Transmission customers in Alberta are concerned with the high cost of, and time delays in, connecting to the system when they are entirely reliant on the incumbent transmission facility operator to connect. Based on these concerns, the Government of Alberta and AESO have held consultations that could lead to transmission customers, including potentially FortisAlberta, constructing, owning and operating required transmission facilities.

Opportunity exists for FortisOntario to invest in the development of the East-West Tie, a new 400-kilometre double-circuit 230-kilovolt transmission line from Thunder Bay to Wawa, which is estimated to cost approximately $600 million. FortisOntario is partnering with Lake Huron Anishinabek First Nations on this potential project and has submitted a designation application with the regulator in January 2013. Northwestern Ontario also represents opportunity for development of new transmission lines, including transmission connections to remote First Nations communities and certain mining and renewable generation developments. The potential transmission development in the region is estimated to be greater than $1 billion, net of customer contributions. FortisOntario's objective is to continue to work with First Nations to negotiate binding Memorandums of Understanding for exclusivity around the potential development of the new transmission infrastructure.

There is a significant infrastructure investment opportunity for CH Energy Group pertaining to the New York State Bulk Power Transmission Facilities. Although well maintained, New York State's Bulk Power System is aging and the transmission facilities' infrastructure must be rebuilt, rehabilitated, modernized and expanded to reliably and economically meet the future energy needs of customers, including energy sources from renewables. New York State-mandated Renewable Portfolio Standards requirements will increase from 20% in 2013 to 30% in 2015. Of the 1,400 MW of existing renewable supply, large-scale wind generation comprises 1,275 MW. The New York Independent System Operator studied the impact of integrating 3,500 MW to 8,000 MW of wind generation into the State's power system and found that extensive new transmission would result in the "un-bottling" of new wind resources, allowing for wider deliverability of renewable resources throughout the State.

Greenhouse Gas Emissions: Implemented and potential government legislation, driven by concerns that GHG emissions contribute to climate change, has significant implications for the energy industry. The most significant impact for Fortis with respect to GHG emissions legislation pertains to FortisBC's gas business as it relates to the combustion of and/or release of natural gas.

The impact of GHG emissions is lower at the Corporation's Canadian Regulated Electric Utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric and about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity, is hydroelectric, a clean energy source. The 335-MW Waneta Expansion will be another clean renewable hydroelectric energy source when it comes into service in spring 2015. Only a small portion of in-house generation at Canadian Regulated Electric Utilities uses diesel fuel. There is no coal-fired generation within any of the Corporation's operations. Canadian Regulated Electric Utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

While renewable energy sources, including wind, solar and biogas, account for a small portion of power generation in the world today, given the realities of climate change and the increasing pressure from policymakers and public opinion, they are projected to be the fastest growing source of energy going forward. However, renewables are starting from a very small base, are still maturing technologically and, in most cases, need government support to be price competitive with other fuels.

Development opportunities exist in British Columbia in the thermal energy services sector, including district energy, geo-exchange and combined heat and power systems. Applications have been filed with the British Columbia Utilities Commission ("BCUC") with regard to various thermal energy projects proposed to be undertaken by FAES. For further information, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities issue debt usually at terms ranging between 10 and 50 years. As at December 31, 2012, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $2.5 billion in credit facilities, of which approximately $2.1 billion was unused as at December 31, 2012. With strong credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2013.

Dividend Increases: Dividends paid per common share increased to $1.20 in 2012. Fortis increased its quarterly common share dividend to 31 cents, commencing with the first quarter dividend paid in 2013. The 3.3% increase in the quarterly common share dividend translates into an annualized dividend of $1.24 for 2013 and extends the Corporation's record of annual common share dividend increases to 40 consecutive years, the longest record of any public corporation in Canada. Fortis expects that investment in its utilities associated with their capital expenditure programs will support continuing growth in earnings and dividends.

Caribbean Operating Environment: Regulated assets in the Caribbean region comprised 7% of the Corporation's total regulated assets as at December 31, 2012 (December 31, 2011 – 7%). Generally, the achieved ROA at electric utilities in the Caribbean region is higher than that achieved by electric utilities in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors, as well as weather conditions, including a significant exposure to hurricanes. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruptions associated with hurricanes.

While still higher than that achieved by regulated utilities in Canada, the allowed ROA at Caribbean Utilities was lowered beginning in 2008 due to the negotiation of new licences at the utility. Also, the achieved ROA at FortisTCI has been significantly lower than that allowed under its licence as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

Expropriated Assets: The GOB expropriated the Corporation's common share ownership in Belize Electricity in June 2011. The Corporation is challenging the constitutionality of the expropriation in the Belize Courts. Although the GOB initiated contact with Fortis, there has been no settlement on the fair value compensation owing to Fortis as a result of the expropriation. For further information, refer to the "Business Risk Management – Expropriation of Shares in Belize Electricity" section of this MD&A.

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. The book value of the Corporation's net investment in the Exploits Partnership is approximately $4 million and is recorded in long-term other assets on the consolidated balance sheet. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

SIGNIFICANT ITEMS

Pending Acquisition of CH Energy Group: In February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from FERC and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction.

Approval by the New York State Public Service Commission ("NYSPSC") of the Corporation's acquisition of CH Energy Group is the last significant regulatory matter required to close the transaction. Closing of the transaction is now anticipated during the second quarter of 2013. The transaction is expected to be accretive to the Corporation's earnings per common share within the first full year of ownership of CH Energy Group, excluding acquisition-related expenses. A Settlement Agreement among Fortis, CH Energy Group, NYSPSC staff, registered interveners and other parties was filed with the NYSPSC in January 2013. The Settlement Agreement provides almost $50 million to fund customer and community benefits, including: (i) $35 million to cover expenses that normally would be recovered in customer rates, for example, storm-restoration expenses; (ii) guaranteed savings to customers of more than $9 million over five years resulting from the elimination of costs Central Hudson now incurs as a public company; and (iii) the establishment of a $5 million Customer Benefit Fund for economic development and low-income assistance programs for communities and residents of the Mid-Hudson River Valley. Another benefit provided under the Settlement Agreement is an electric and natural gas customer delivery rate freeze until July 1, 2014. The Settlement Agreement also contains customer protections, including the continuation of Central Hudson as a stand-alone utility. The parties to the Settlement Agreement have concluded that, based on the terms of the Settlement Agreement, the acquisition is in the public interest and have recommended approval by the NYSPSC.

During 2012 the Corporation's earnings were reduced by the incurrence of $7.5 million of after-tax CH Energy Group acquisition-related expenses, largely incurred in the first half of 2012. Fortis expects to incur additional acquisition-related expenses in 2013 related to closing the transaction.

Management Discussion and Analysis

Subscription Receipts Offering: To finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18.5 million Subscription Receipts at $32.50 each in June 2012 through a bought deal offering underwritten by a syndicate of underwriters, realizing gross proceeds of approximately $601 million. The gross proceeds from the sale of the Subscription Receipts are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, included in the agreement to acquire CH Energy Group ("Release Conditions"). The Subscription Receipts began trading on the TSX on June 27, 2012 under the symbol "FTS.R".

Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts to holders of record.

If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition of CH Energy Group is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount.

For further information on the pending acquisition and the related Subscription Receipts offering, refer to the "Business Risk Management – Completion of the Acquisition of CH Energy Group" section of this MD&A.

Receipt of Regulatory Decisions: Regulatory decisions were received in 2012 for 2012/2013 revenue requirements at the FortisBC Energy companies and FortisBC Electric, and for 2012 revenue requirements at FortisAlberta. The Alberta Utilities Commission ("AUC") issued a generic decision in September 2012 on its PBR Initiative ("PBR Decision"), outlining the PBR framework applicable to distribution utilities in Alberta for a five-year term, which commenced January 1, 2013. For further information, refer to the "Regulatory Highlights" and "Business Risk Management – Regulatory Risk" sections of this MD&A.

First Preference Share Offering: In November 2012 Fortis issued 8 million 4.75% First Preference Shares, Series J at $25.00 per share for total proceeds of approximately $200 million. The net proceeds of $194 million were used to repay borrowings under the Corporation's committed corporate credit facility, which borrowings were primarily incurred to support the construction of the non-regulated Waneta Expansion and for other general corporate purposes.

Long-Term Debt Offering – FortisAlberta: In October 2012 FortisAlberta issued 40-year $125 million 3.98% unsecured debentures. The net proceeds of the debt offering are being used to repay borrowings under the Company's credit facility incurred to finance capital expenditures, to fund future capital expenditures and for general corporate purposes.

Part VI.1 Tax: Under the terms of the Corporation's first preference shares, the Corporation is subject to tax under Part VI.1 of the *Income Tax Act* (Canada) associated with dividends on its first preference shares. For corporations subject to Part VI.1 tax, there is an equivalent Part I tax deduction. As permitted under the *Income Tax Act* (Canada), a corporation may allocate its Part VI.1 tax liability and equivalent Part I tax deduction to its related subsidiaries. In the past, Fortis has allocated these items to Maritime Electric, Newfoundland Power and FortisOntario.

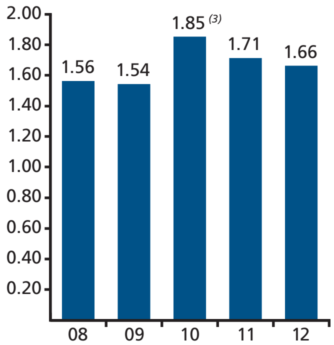
Upon transition to US GAAP, the Corporation reduced its consolidated opening 2012 retained earnings by $20 million to reflect the impact of differences between enacted and substantively enacted tax legislation associated with prior assessments and payments of Part VI.1 taxes, and the recovery of Part I taxes. The adjustment was required because US GAAP requires tax provisions to be based on enacted versus substantively enacted legislation. A number of legislative amendments to Part VI.1 tax in Canada have yet to be enacted. The above-noted transitional US GAAP adjustment, as well as certain amounts recognized in 2012, will reverse through the Corporation's earnings in future periods when the legislation is finally enacted, which is expected in 2013, or as reassessment of corporate taxation years, upon which the enacted versus substantively enacted rates were used to calculate taxes payable under US GAAP for financial reporting purposes, become statute-barred. During 2012 Newfoundland Power recorded a favourable $2.5 million adjustment to income taxes associated with statute-barred Part VI.1 taxes (2011 – $1 million). For further information, refer to the "Business Risk Management – Changes in Tax Legislation" section of this MD&A.

Transition to US GAAP: Effective January 1, 2012, Fortis retroactively adopted US GAAP with the restatement of comparative reporting periods. For further information, refer to the "New Accounting Standards and Policies – Transition to US GAAP" section of this MD&A.

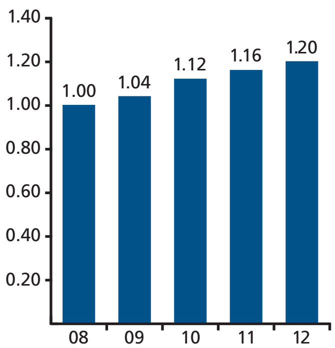
SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	2012	2011	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**315**	311	4
Basic Earnings per Common Share *($)*	**1.66**	1.71	(0.05)
Diluted Earnings per Common Share *($)*	**1.65**	1.70	(0.05)
Weighted Average Number of Common Shares Outstanding *(millions)*	**190.0**	181.6	8.4
Cash Flow from Operating Activities *($ millions)*	**976**	915	61
Dividends Paid per Common Share *($)*	**1.20**	1.16	0.04
Dividend Payout Ratio *(%)*	**72.3**	67.8	4.5
Return on Average Book Common Shareholders' Equity *(%)* (1)	**8.1**	8.8	(0.7)
Total Assets *($ billions)*	**15.0**	14.2	0.8
Gross Capital Expenditures *($ millions)*	**1,130**	1,171	(41)
Public Common Share Offering *($ millions)*	**–**	341	(341)
Public Preference Share Offering *($ millions)*	**200**	–	200
Long-Term Debt Offerings *($ millions)*	**125**	347	(222)

Basic Earnings per Common Share *($)* (2)



Dividends Paid per Common Share *($)*



Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $315 million in 2012, up $4 million from $311 million in 2011. Earnings in 2012 were reduced by $7.5 million of after-tax CH Energy Group acquisition-related expenses, while earnings in 2011 were favourably impacted by a one-time $11 million after-tax fee paid to Fortis following the termination of a Merger Agreement with Central Vermont Public Service Corporation ("CVPS"). Excluding these items, growth in earnings to common equity shareholders year over year was driven by improved performance at Canadian Regulated Utilities, led by FortisAlberta.

Earnings at Canadian Regulated Electric Utilities were up $33 million from 2011. FortisAlberta's earnings increased $22 million, mainly related to growth in energy infrastructure investment, net transmission revenue of $8.5 million recognized in 2012, and lower-than-expected depreciation expense and finance charges in 2012, partially offset by a $1 million gain on the sale of property in 2011. Newfoundland Power's earnings were $5 million higher year over year, largely due to lower effective income taxes. FortisBC Electric's earnings increased $2 million as a result of growth in energy infrastructure investment, higher pole-attachment revenue and lower-than-expected finance charges in 2012, partially offset by the discontinuance of the PBR mechanism on December 31, 2011. Improved earnings of $4 million at Other Canadian Regulated Electric Utilities were mainly due to lower effective income taxes at Maritime Electric and cumulative return earned on capital investment in smart meters at FortisOntario.

Canadian Regulated Gas Utilities delivered earnings $1 million higher than in 2011. Growth in energy infrastructure investment, higher gas transportation volumes to industrial customers, lower-than-expected operating expenses in 2012 and lower effective income taxes were partially offset by lower-than-expected customer additions in 2012 and lower capitalized allowance for funds used during construction ("AFUDC").

Corporate and other expenses were up $27 million from 2011. Excluding CH Energy Group acquisition-related expenses, incurred largely in the first half of 2012, and the merger termination fee paid to Fortis in July 2011, corporate and other expenses were $8.5 million higher year over year. The increase was mainly the result of a $2 million foreign exchange loss recognized in 2012 compared to a $1.5 million after-tax net foreign exchange gain recognized in 2011, certain non-recurring operating expenses in 2012 and lower effective income tax recoveries, partially offset by lower finance charges.

(1) Return on average book common shareholders' equity is a non-GAAP measure and is defined as consolidated net earnings attributable to common equity shareholders divided by the average of consolidated opening and closing shareholders' equity, excluding preference equity and non-controlling interests.

(2) Years 2010 through 2012 prepared in accordance with US GAAP. Years 2008 and 2009 prepared in accordance with Canadian GAAP.

(3) Includes the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with OPEBs upon the adoption of US GAAP.

Basic Earnings per Common Share: Basic earnings per common share were $1.66 in 2012 compared to $1.71 in 2011. The decrease was due to the impact of a 5% increase in the weighted average number of common shares outstanding year over year, largely associated with the issuance of common equity in mid-2011, partially offset by higher net earnings attributable to common equity shareholders. Proceeds from the common share offering were largely used to repay borrowings under credit facilities, support the construction of the Waneta Expansion and for other general corporate purposes and helped to contribute to the strengthening of the Corporation's capital structure.

Cash Flow from Operating Activities: Cash flow from operating activities was $976 million for 2012, up $61 million from $915 million for 2011. The increase was primarily due to higher earnings and the collection from customers of regulator-approved increased depreciation and amortization, partially offset by unfavourable changes in working capital.

Dividends: Dividends paid per common share increased to $1.20 in 2012, up 3.4% from $1.16 in 2011. Fortis increased its quarterly common share dividend to 31 cents from 30 cents, commencing with the first quarter dividend paid on March 1, 2013. The Corporation's dividend payout ratio was 72.3% in 2012 compared to 67.8% in 2011.

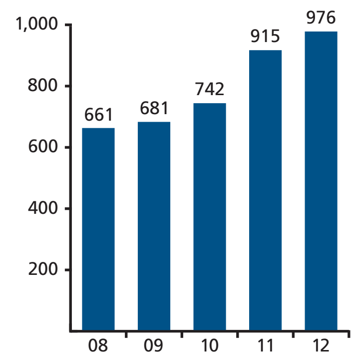
Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity was 8.1% in 2012 compared to 8.8% in 2011. The decrease was mainly a result of higher common shares outstanding, for the reason discussed above, partially offset by an increase in earnings attributable to common equity shareholders.

Total Assets: Total assets increased 5.6% to approximately $15.0 billion at the end of 2012 compared to approximately $14.2 billion at the end of 2011. The increase reflected the Corporation's continued investment in regulated energy systems, driven by capital spending in western Canada, and the continued construction of the non-regulated Waneta Expansion in British Columbia.

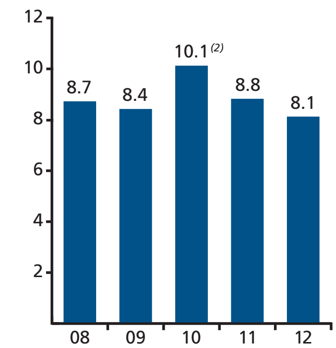
Gross Capital Expenditures: During 2012 consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,130 million compared to $1,171 million in 2011. Total capital investment at the regulated utilities in western Canada was approximately $717 million, representing approximately 63% of total gross capital expenditures. Much of the capital investment was driven by customer growth, and the need to enhance the reliability and efficiency of energy systems and improve customer service. Construction progress on the $900 million, 335-MW Waneta Expansion is going well and the project is currently on schedule and on budget. Approximately $436 million in total has been spent on the Waneta Expansion since construction began late in 2010, with $192 million spent in 2012. For a further discussion of the Corporation's 2012 and 2013 consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: In November 2012 Fortis issued 8 million 4.75% First Preference Shares, Series J for total proceeds of $200 million and in October 2012 FortisAlberta issued 40-year $125 million 3.98% unsecured debentures. For further information, refer to the "Significant Items" section of this MD&A.

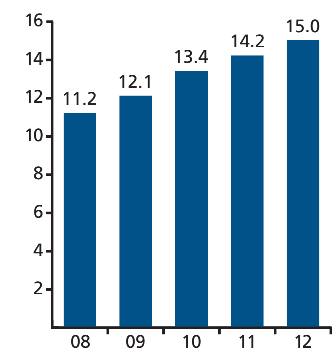
Cash Flow from Operating Activities *($ millions)* [(1)]



Return on Average Book Common Shareholders' Equity *(%)* [(1)]



Total Assets *($ billions)*
(as at December 31) [(1)]



[(1)] Years 2010 through 2012 prepared in accordance with US GAAP. Years 2008 and 2009 prepared in accordance with Canadian GAAP.

[(2)] Includes the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with OPEBs upon the adoption of US GAAP.

CONSOLIDATED RESULTS OF OPERATIONS

The Corporation's consolidated results of operations for 2012 and 2011 are outlined below, including a discussion of the nature of the variances year over year.

Years Ended December 31 *($ millions)*	**2012**	2011	Variance
Revenue	**3,654**	3,738	(84)
Energy Supply Costs	**1,522**	1,697	(175)
Operating Expenses	**868**	850	18
Depreciation and Amortization	**470**	416	54
Other Income, Net	**4**	38	(34)
Finance Charges	**366**	363	3
Income Taxes	**61**	84	(23)
Net Earnings	**371**	366	5
Net Earnings Attributable to:			
Non-Controlling Interests	**9**	9	–
Preference Equity Shareholders	**47**	46	1
Common Equity Shareholders	**315**	311	4
Net Earnings	**371**	366	5

Factors Contributing to Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which reduced revenue year over year
- Lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures
- Decreased non-regulated hydroelectric production, mainly due to lower rainfall and a generating facility in Upstate New York being out of service in 2012

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the regulated utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Net transmission revenue of approximately $8.5 million recognized in 2012 at FortisAlberta as a result of the 2012 distribution revenue requirements decision received in April 2012
- The flow through in customer electricity rates of higher energy supply costs, where applicable, at most of the regulated electric utilities, which increased revenue
- Increased electricity sales at Newfoundland Power and Maritime Electric
- A $4 million increase in franchise fee revenue at FortisAlberta
- Growth in the number of customers, driven by FortisAlberta
- Higher pole-attachment revenue at FortisBC Electric and differences in the amount of PBR incentives refunded to FortisBC Electric's customers year over year
- Higher Hospitality revenue at Fortis Properties, driven by revenue from the Hilton Suites Hotel, which was acquired in October 2011

Factors Contributing to Energy Supply Costs Variance

Favourable

- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which reduced energy supply costs year over year
- Lower average gas consumption by residential and commercial customers, which reduced natural gas purchases

Unfavourable

- Increased fuel prices at Caribbean Utilities and increased purchased power costs at FortisBC Electric, Newfoundland Power and FortisOntario
- An increase in the base amount of energy supply costs expensed at Maritime Electric in accordance with the operation of the Energy Cost Adjustment Mechanism
- Increased electricity sales at Newfoundland Power and Maritime Electric, which increased power purchases

Factors Contributing to Operating Expenses Variance

Unfavourable

- General inflationary and employee-related cost increases at the Corporation's regulated utilities, and increased franchise fee expenses at FortisAlberta
- Higher operating expenses at Fortis Properties, mainly associated with the Hilton Suites Hotel, which was acquired in October 2011
- A $3 million non-recurring provision recognized in 2012 associated with the Corporation's investment in CWLP

Favourable

- Reduced operating expenses at the FortisBC Energy companies during 2012, mainly due to the accrual of non-asset retirement obligation ("non-ARO") removal costs in depreciation, effective January 1, 2012, and lower customer care-related costs as a result of insourcing the customer care function, effective January 1, 2012. Non-ARO removal costs were recorded in operating expenses in 2011.
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased operating expenses year over year

Factors Contributing to Depreciation and Amortization Variance

Unfavourable

- Continued investment in energy infrastructure
- Increased depreciation at the FortisBC Energy companies, mainly due to the accrual of non-ARO removal costs in depreciation, effective January 1, 2012, as discussed above

Favourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased depreciation year over year
- Lower depreciation rates at FortisAlberta and FortisBC Electric, effective January 1, 2012, as a result of the 2012 revenue requirements decisions received in April 2012 and August 2012, respectively

Factors Contributing to Other Income, Net Variance

Unfavourable

- The $17 million (US$17.5 million) ($11 million after-tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS, which increased other income in 2011
- Approximately $9 million ($7.5 million after tax) of costs, incurred largely in the first half of 2012, related to the pending acquisition of CH Energy Group
- A foreign exchange loss of approximately $2 million recognized in 2012 associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity. A net foreign exchange gain of approximately $1 million ($1.5 million after tax) was recognized in 2011 related to the above item.
- Lower capitalized equity component of AFUDC, mainly at the FortisBC Energy companies
- An approximate $1 million gain on the sale of property at FortisAlberta in 2011

Favourable

- An approximate $1 million ($0.5 million after-tax) gain recognized in 2012 on the involuntary disposition of assets associated with damaged equipment at a generating facility in Upstate New York and related proceeds received under an insurance claim

Factors Contributing to Finance Charges Variance

Unfavourable

- Higher long-term debt levels in support of the utilities' capital expenditure programs
- Lower capitalized debt component of AFUDC at the regulated utilities, mainly at the FortisBC Energy companies

Favourable

- Higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased finance charges year over year
- Lower short-term borrowings at the regulated utilities

Factors Contributing to Income Taxes Variance

Favourable

- Lower statutory income tax rates and lower earnings before income taxes
- Differences in deductions for income tax purposes compared to accounting purposes year over year

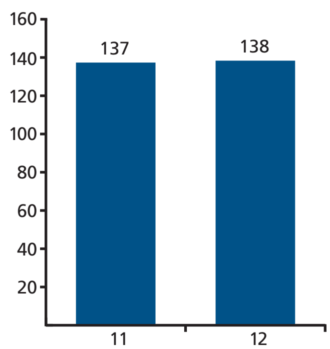
SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31 *($ millions)*	**2012**	2011	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**138**	137	1
Regulated Electric Utilities – Canadian			
FortisAlberta	**96**	74	22
FortisBC Electric	**50**	48	2
Newfoundland Power	**37**	32	5
Other Canadian Electric Utilities	**24**	20	4
	207	174	33
Regulated Electric Utilities – Caribbean	**19**	20	(1)
Non-Regulated – Fortis Generation	**17**	18	(1)
Non-Regulated – Fortis Properties	**22**	23	(1)
Corporate and Other	**(88)**	(61)	(27)
Net Earnings Attributable to Common Equity Shareholders	**315**	311	4

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A. A discussion of the Corporation's gross consolidated capital expenditure program and breakdown of actual 2012 and forecasted 2013 gross consolidated capital expenditures by segment is provided in the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Regulated Gas Utilities – Canadian Earnings *($ millions)*



REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2012 regulated earnings in Canada and the Caribbean represented approximately 90% (2011 – 89%) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment net loss). Total regulated assets represented 90% of the Corporation's total assets as at December 31, 2012 (December 31, 2011 – 91%).

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2012 were $138 million (2011 – $137 million), which represented approximately 38% of the Corporation's total regulated earnings (2011 – 41%). Regulated Gas Utilities – Canadian assets were approximately $5.5 billion as at December 31, 2012 (December 31, 2011 – $5.5 billion), which represented approximately 41% of the Corporation's total regulated assets as at December 31, 2012 (December 31, 2011 – 42%).

FortisBC Energy Companies

Financial Highlights

Years Ended December 31	**2012**	2011	Variance
Gas Volumes *(petajoules ("PJ"))*	**199**	203	(4)
Revenue *($ millions)*	**1,426**	1,566	(140)
Earnings *($ millions)*	**138**	137	1

Factors Contributing to Gas Volumes Variance

Unfavourable

- Lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures

Favourable

- Higher gas transportation volumes to industrial customers, due to certain customers switching to natural gas from alternative sources of fuel as a result of low natural gas prices

With the implementation of the Customer Care Enhancement Project on January 1, 2012, the FortisBC Energy companies changed their definition of a customer. As a result of this change, the FortisBC Energy companies reduced their combined customer count by approximately 18,000 as at January 1, 2012. As at December 31, 2012, the total number of customers served by the FortisBC Energy companies was approximately 945,000, up 7,000 customers from January 1, 2012.

Management Discussion and Analysis

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

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

Factors Contributing to Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower average gas consumption by residential and commercial customers
- Lower-than-expected customer additions in 2012

Favourable

- A net increase in the delivery component of customer rates, effective January 1, 2012, mainly due to ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers as reflected in the 2012/2013 revenue requirements decision received in April 2012
- Higher gas transportation volumes to industrial customers

Factors Contributing to Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Higher gas transportation volumes to industrial customers
- Lower-than-expected operating and maintenance expenses during 2012
- Lower effective income taxes

Unfavourable

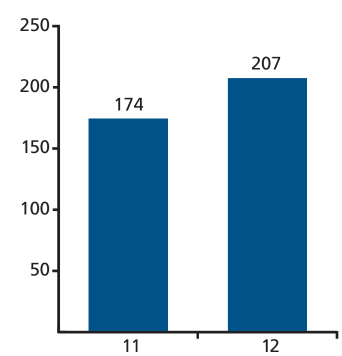
- Lower-than-expected customer additions in 2012
- Lower capitalized AFUDC, due to lower assets under construction year over year

Outlook: The determination of final allowed ROEs and capital structures for the FortisBC Energy companies for 2013 is subject to the outcome of the BCUC's decision on the Generic Cost of Capital ("GCOC") Proceeding. Except for the potential impact of a decision on the GCOC Proceeding, customer delivery rates at the FortisBC Energy companies for 2013 have been set as approved by the BCUC in its April 2012 decision on the utilities' 2012/2013 revenue requirements. All else being equal, each 50 basis point change in the allowed ROEs would have an approximate $7 million impact on earnings of the FortisBC Energy companies for 2013. All else being equal, each 100 basis point change in the percentage of common equity to total capital structure would have an approximate $3.5 million impact on earnings of the FortisBC Energy companies for 2013.

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2012 were $207 million (2011 – $174 million), which represented approximately 57% of the Corporation's total regulated earnings (2011 – 53%). Regulated Electric Utilities – Canadian assets were approximately $7.1 billion as at December 31, 2012 (December 31, 2011 – $6.6 billion), which represented approximately 53% of the Corporation's total regulated assets as at December 31, 2012 (December 31, 2011 – 51%).

Regulated Electric Utilities – Canadian Earnings *($ millions)*



FortisAlberta

Financial Highlights

Years Ended December 31	2012	2011	Variance
Energy Deliveries *(gigawatt hours ("GWh"))*	**16,799**	16,367	432
Revenue *($ millions)*	**448**	408	40
Earnings *($ millions)*	**96**	74	22

Factors Contributing to Energy Deliveries Variance

Favourable

- Higher average consumption by oil field and commercial customers, due to increased activity
- Higher average consumption by residential customers, driven by cooler temperatures in the fourth quarter, which increased heating load
- Growth in the number of customers, mainly in the residential and commercial sectors, with the total number of customers increasing by approximately 9,000 year over year, driven by favourable economic conditions

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

Factors Contributing to Revenue Variance

Favourable

- An increase in customer electricity distribution rates, effective January 1, 2012, driven primarily by ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Net transmission revenue of approximately $8.5 million recognized in 2012. In its April 2012 distribution revenue requirements decision, the regulator did not approve the continuation in 2012 of the deferral of transmission volume variances associated with FortisAlberta's AESO charges deferral account. In the absence of full deferral, FortisAlberta was subject to volume risk in 2012 on actual transmission costs relative to those charged to customers based on forecasted volumes and prices. Transmission volumes are influenced by many factors, which may result in actual transmission volumes varying from those forecasted. The deferral of transmission volume variances was reinstated, effective January 1, 2013, as approved by the regulator and, therefore, such variances will not impact earnings in 2013.
- Growth in the number of customers, as discussed above
- An increase in franchise fee revenue of approximately $4 million

Factors Contributing to Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Net transmission revenue of approximately $8.5 million recognized in 2012 as a result of the distribution revenue requirements decision received in April 2012
- Lower-than-expected depreciation in 2012, mainly due to construction projects being completed later in the year and lower AESO transmission-related capital expenditures
- Lower-than-expected finance charges in 2012 associated with the timing of debt issuances and associated interest rates on the debt

Unfavourable

- An approximate $1 million gain on the sale of property in 2011

Outlook: The determination of FortisAlberta's final allowed ROE and capital structure for 2013 is subject to the outcome of an AUC-initiated GCOC Proceeding, which is expected to occur later in 2013. All else being equal, each 50 basis point change in FortisAlberta's allowed ROE would have an approximate $5 million impact on FortisAlberta's earnings for 2013. All else being equal, each 100 basis point change in the percentage of common equity to total capital structure would have an approximate $2 million impact on FortisAlberta's earnings for 2013. Effective January 1, 2013, FortisAlberta is subject to PBR for a five-year term. The PBR mechanism raises some concern and uncertainty for FortisAlberta regarding the treatment of certain capital expenditures. FortisAlberta along with other distribution utilities operating in Alberta have requested leave to appeal the PBR Decision to the Alberta Court of Appeal. In March 2013 the regulator issued an interim decision on FortisAlberta's Compliance Application approving a 1.71% increase in customer distribution rates and 60% of the revenue requirement associated with the utility's 2013 Capital Tracker Application, effective January 1, 2013. Final decisions on the Compliance and Capital Tracker Applications are expected later in 2013. For a further discussion on this matter, refer to the "Regulatory Highlights" and "Business Risk Management – Regulatory Risk" sections of this MD&A.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2012**	2011	Variance
Electricity Sales *(GWh)*	**3,143**	3,143	–
Revenue *($ millions)*	**306**	296	10
Earnings *($ millions)*	**50**	48	2

Factors Contributing to Revenue Variance

Favourable

- An overall increase in customer electricity rates, effective January 1, 2012, mainly due to ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers as reflected in the 2012/2013 revenue requirements decision received in August 2012
- A 1.4% increase in customer electricity rates, effective June 1, 2011, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- Higher pole-attachment revenue
- Higher wheeling revenue
- Differences in the amount of PBR incentives refunded to customers year over year

Factors Contributing to Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Higher pole-attachment revenue
- Lower-than-expected finance charges in 2012. As approved in the 2012/2013 revenue requirements decision received in August 2012, variances between actual finance charges and those forecasted in determining customer electricity rates, beginning January 1, 2012, are no longer permitted deferral account treatment and, therefore, favourably impacted earnings in 2012.

Unfavourable

- The expiry of the PBR mechanism on December 31, 2011. In 2011 lower-than-expected costs, primarily purchased power costs, which were shared equally between customers and FortisBC Electric under the PBR mechanism, favourably impacted earnings in that year. In 2012 variances between actual electricity revenue and purchased power costs and those used in determining customer electricity rates were subject to full deferral account treatment and, therefore, did not impact earnings in 2012.

Outlook: The determination of FortisBC Electric's final allowed ROE and capital structure for 2013 is subject to the outcome of the BCUC's decision on the GCOC Proceeding. Except for the potential impact of a decision on the GCOC Proceeding, customer electricity rates at FortisBC Electric for 2013 have been set as approved by the BCUC in its August 2012 decision on the utility's 2012/2013 revenue requirements. All else being equal, each 50 basis point change in FortisBC Electric's allowed ROE would have an approximate $2.5 million impact on FortisBC Electric's earnings for 2013. All else being equal, each 100 basis point change in the percentage of common equity to total capital structure would have an approximate $1 million impact on FortisBC Electric's earnings for 2013.

Newfoundland Power

Financial Highlights

Years Ended December 31	**2012**	2011	Variance
Electricity Sales *(GWh)*	**5,652**	5,553	99
Revenue *($ millions)*	**581**	573	8
Earnings *($ millions)*	**37**	32	5

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers
- Higher concentration of electric-versus-oil heating in new home construction combined with economic growth, which increased consumption

Unfavourable

- Sunnier weather conditions, which reduced average consumption

Factors Contributing to Revenue Variance

Favourable

- The 1.8% increase in electricity sales
- Increased amortization to revenue of regulatory liabilities and deferrals, as approved by the regulator

Unfavourable

- Revenue for 2011 included amounts related to support structure arrangements, which were in place with Bell Aliant Regional Communications Inc. ("Bell Aliant") during 2011, associated with the joint-use poles and related infrastructure held for sale to Bell Aliant. The joint-use poles and related infrastructure were sold in October 2011.

Factors Contributing to Earnings Variance

Favourable

- Lower effective income taxes, primarily due to lower Part VI.1 taxes, including the favourable impact of reversals of statute-barred Part VI.1 taxes and a lower statutory income tax rate. For further information on Part VI.1 taxes, refer to the "Significant Items – Part VI.1 Tax" section of this MD&A.
- An increase in the allowed ROE from 8.38% to 8.80%, effective January 1, 2012, which was accrued in 2012, as approved by the regulator, as a decrease in operating expenses for deferred recovery from customers
- Electricity sales growth

Unfavourable

- The impact of the support structure arrangements with Bell Aliant during 2011, as discussed above
- Higher purchased power costs, as a result of lower generation associated with the Company's hydroelectric generating facilities in 2012 due to lower water inflows
- Higher depreciation, due to continued investment in energy infrastructure

Outlook: Customer rates, capital structure and the allowed ROE at Newfoundland Power for 2013 are subject to the outcome of a decision on Newfoundland Power's 2013/2014 General Rate Application. All else being equal, each 50 basis point change in Newfoundland Power's allowed ROE would have an approximate $2 million impact on Newfoundland Power's earnings for 2013. All else being equal, each 100 basis point change in the percentage of common equity to total capital structure would have an approximate $1 million impact on Newfoundland Power's earnings for 2013.

Other Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2012**	2011	Variance
Electricity Sales *(GWh)*	**2,381**	2,366	15
Revenue *($ millions)*	**353**	339	14
Earnings *($ millions)*	**24**	20	4

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of residential and commercial customers on PEI
- Higher average consumption by residential customers on PEI, due to colder temperatures, and an increase in the number of such customers using electricity for home heating
- Higher average consumption by commercial customers in the agricultural processing sector on PEI

Unfavourable

- Lower average consumption by residential and industrial customers in Ontario, primarily during the first quarter of 2012, reflecting more moderate temperatures and weak economic conditions in the region

Factors Contributing to Revenue Variance

Favourable

- The overall 0.6% increase in electricity sales
- An increase in the basic component of customer rates at Maritime Electric, effective March 1, 2012, associated with the higher flow through and recovery of energy supply costs
- The accrual of cumulative return earned on FortisOntario's capital investment in smart meters, of which approximately $0.5 million related to prior years
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- Increased base customer electricity rates at FortisOntario

Factors Contributing to Earnings Variance

Favourable

- Lower effective income taxes at Maritime Electric, primarily due to lower Part VI.1 taxes
- The accrual of cumulative return earned on FortisOntario's capital investment in smart meters, of which approximately $0.5 million related to prior years
- Higher earnings contribution by FortisOntario's operations in Cornwall, due to an increase in base customer electricity rates
- Net cost savings at FortisOntario in 2012 associated with the exercise of the Company's option to purchase all of the electricity distribution assets previously leased under an operating lease agreement with the City of Port Colborne

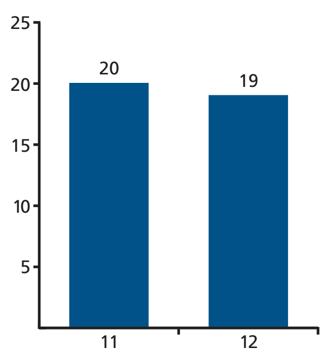
In April 2012 FortisOntario exercised its option to purchase all of the assets previously leased by the Company under an operating lease agreement with the City of Port Colborne for the purchase option price of approximately $7 million. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, which constitute the electricity distribution system in Port Colborne.

Outlook: Under the newly enacted *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("*Accord Continuation Act*"), customer electricity rate increases and the allowed ROE of 9.75% at Maritime Electric have been set for the three-year period ending February 29, 2016.

A regulatory decision on Algoma Power's Third-Generation Incentive Rate Mechanism ("IRM") application for electricity distribution rates, effective January 1, 2013, is pending. The utility's allowed ROE for 2013 of 9.85% remains unchanged from 2012.

Canadian Niagara Power's allowed ROE for 2013, as calculated under formula, is set at 8.93% for 2013, up from 8.01% for 2012. Also, electricity distribution rates, effective January 1, 2013, rebased using a 2013 forward test year, have been approved by the Ontario Energy Board ("OEB").

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Earnings contribution from Regulated Electric Utilities – Caribbean for 2012 was $19 million (2011 – $20 million), which represented approximately 5% of the Corporation's total regulated earnings (2011 – 6%). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2012 (December 31, 2011 – $0.9 billion), which represented approximately 6% of the Corporation's total regulated assets as at December 31, 2012 (December 31, 2011 – 7%).

Financial Highlights

Years Ended December 31	2012	2011	Variance
Average US:CDN Exchange Rate [(1)]	**1.00**	0.99	0.01
Electricity Sales *(GWh)*	**728**	918	(190)
Revenue *($ millions)*	**273**	305	(32)
Earnings *($ millions)*	**19**	20	(1)

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

Factors Contributing to Electricity Sales Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. Excluding Belize Electricity, electricity sales increased 0.6% year over year.
- Higher rainfall and cooler temperatures experienced on Grand Cayman, combined with continued weak economic conditions in the region, decreased air conditioning load

Favourable

- Electricity sales of 8 GWh at TCU, which was acquired in August 2012, higher tourism activity in the Turks and Caicos Islands and growth in the number of customers, excluding the impact of customers acquired with TCU

Factors Contributing to Revenue Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased revenue by approximately $45 million year over year
- The discontinuance of government subsidization of FortisTCI's South Caicos operations, effective April 1, 2012, in accordance with a rate decision received in February 2012
- Decreased electricity sales at Caribbean Utilities

Favourable

- Increased electricity sales at FortisTCI
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel, which increased revenue
- An increase in electricity rates for FortisTCI's large hotel customers, effective April 1, 2012, in accordance with a rate decision received in February 2012
- An increase in base electricity rates at Caribbean Utilities, effective June 1, 2012
- Approximately $3 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar year over year

Factors Contributing to Earnings Variance

Unfavourable

- Excluding foreign exchange impacts, overall higher depreciation, due to continued investment in energy infrastructure
- Excluding foreign exchange impacts, higher finance charges at FortisTCI associated with lower capitalized AFUDC and debt incurred to finance the acquisition of TCU
- Decreased electricity sales at Caribbean Utilities

Favourable

- Increased electricity sales at FortisTCI
- Excluding foreign exchange impacts, lower energy supply costs at FortisTCI, mainly due to more fuel-efficient production realized from the use of new generation units at the utility

In August 2012 FortisTCI acquired TCU for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million). TCU is a regulated electric utility operating pursuant to a 50-year licence expiring in 2036. The utility serves more than 2,000 residential and commercial customers on Grand Turk and Salt Cay with a diesel-fired generating capacity of approximately 9 MW.

Outlook: Electricity sales at the Corporation's regulated utilities in the Caribbean are expected to increase 2% to 3% in 2013, excluding sales at TCU, which was acquired by FortisTCI in August 2012. The recovery from the global economic recession continues to be slow, with economic challenges still being faced in the region. Certain specific local development projects on Grand Cayman and the Turks and Caicos Islands, however, may provide a source of limited economic growth going forward. For further information, refer to the "Business Risk Management – Economic Conditions" section of this MD&A.

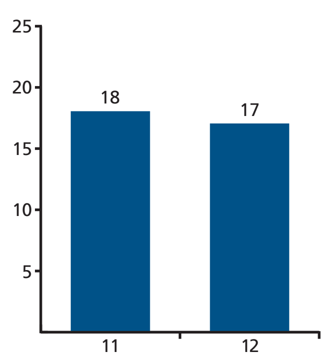
NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	**2012**	2011	Variance
Energy Sales *(GWh)*	**306**	389	(83)
Revenue *($ millions)*	**31**	34	(3)
Earnings *($ millions)*	**17**	18	(1)

Non-Regulated – Fortis Generation Earnings *($ millions)*



Factors Contributing to Energy Sales and Revenue Variances

Unfavourable

- Decreased production in Upstate New York, due to a generating facility being out of service and lower rainfall
- Decreased production in Belize and Ontario, due to lower rainfall

Factors Contributing to Earnings Variance

Unfavourable

- Decreased production in Upstate New York and Ontario
- Decreased production in Belize, partially offset by lower finance charges in Belize

Favourable

- An approximate $1 million ($0.5 million after-tax) gain on the involuntary disposition of assets associated with damaged equipment at Moose River's hydroelectric generating facility in Upstate New York and related proceeds received under an insurance claim

Outlook: The Moose River hydroelectric generating facility returned to service in March 2013. Construction of the non-regulated Waneta Expansion in British Columbia will continue in 2013 and is expected to be completed in spring 2015.

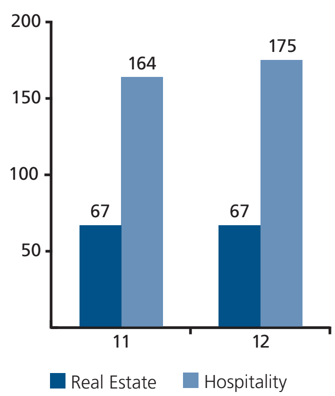
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31	2012	2011	Variance
Hospitality – Revenue per Available Room ("RevPar")	**$ 80.00**	$ 78.76	1.6%
Real Estate – Occupancy Rate *(as at)* (1)	**91.9%**	93.2%	(1.4)%
Hospitality Revenue *($ millions)*	**175**	164	11
Real Estate Revenue *($ millions)*	**67**	67	–
Total Revenue *($ millions)*	**242**	231	11
Earnings *($ millions)*	**22**	23	(1)

(1) Reduced occupancy was primarily due to increased vacancy in New Brunswick.

Fortis Properties
Revenue *($ millions)*



Factors Contributing to RevPar Variance

Favourable

- The Hilton Suites Hotel, acquired in October 2011, contributed 1.2% to the increase in RevPar.
- A 1.5% increase in the average daily room rate, excluding the impact of the Hilton Suites Hotel, due to increases in western Canada and central Canada

Unfavourable

- A 1.1% decrease in occupancy, excluding the impact of the Hilton Suites Hotel, due to decreases in central Canada and Atlantic Canada, partially offset by an increase in western Canada

Factors Contributing to Hospitality Revenue Variance

Favourable

- Revenue contribution from the Hilton Suites Hotel for a full year in 2012 and from the StationPark Hotel for the fourth quarter of 2012
- Higher revenue from operations in western Canada

Unfavourable

- Lower revenue from operations in central Canada and Atlantic Canada

Factors Contributing to Earnings Variance

Unfavourable

- Lower performance at the Hospitality Division, excluding the Hilton Suites Hotel, primarily due to the impact of decreased occupancy at hotel operations in central Canada and Atlantic Canada, partially offset by the impact of increased average room rates and occupancy in western Canada
- Increased depreciation, due to capital additions and improvements

Favourable

- Contribution from the Hilton Suites Hotel for a full year in 2012

In October 2012 Fortis Properties acquired the 126-room StationPark Hotel in London, Ontario for approximately $13 million, inclusive of debt assumed of approximately $6 million.

Outlook: The Hospitality Division will be the primary driver of revenue growth in 2013, mainly attributable to the StationPark Hotel.

The Real Estate Division is expected to produce stable results in 2013. The Real Estate Division operates primarily in Atlantic Canada, where the majority of properties are located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates that help in reducing the risk of vacancy exposure.

For a discussion of the impact of economic conditions on Fortis Properties' operations, refer to the "Business Risk Management – Economic Conditions" section of this MD&A.

Corporate and Other

Financial Highlights

Years Ended December 31 *($ millions)*	2012	2011	Variance
Revenue	**24**	23	1
Operating Expenses	**14**	9	5
Depreciation and Amortization	**2**	2	–
Other (Expenses) Income, Net	**(9)**	21	(30)
Finance Charges	**47**	54	(7)
Income Tax Recovery	**(7)**	(6)	(1)
	(41)	(15)	(26)
Preference Share Dividends	**47**	46	1
Net Corporate and Other Expenses	**(88)**	(61)	(27)

Factors Contributing to Net Corporate and Other Expenses Variance

Unfavourable

- Increased other expenses, net of other income, primarily due to: (i) the favourable impact in 2011 of the $17 million (US$17.5 million) ($11 million after-tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS; (ii) approximately $9 million ($7.5 million after tax) of costs, incurred largely in the first half of 2012, related to the pending acquisition of CH Energy Group; and (iii) a foreign exchange loss of approximately $2 million recognized in 2012, compared to a net foreign exchange gain of approximately $1 million ($1.5 million after tax) recognized in 2011, associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity
- Increased operating expenses, primarily due to a $3 million non-recurring provision recognized in 2012 associated with the Corporation's investment in CWLP, as well as increased employee compensation-related expenses
- Excluding income tax expense associated with the merger termination fee paid to Fortis in July 2011, effective income tax recoveries decreased, primarily due to higher Part VI.1 taxes, partially offset by the release of income tax provisions at FHI in 2012
- Higher preference share dividends, due to the issuance of First Preference Shares, Series J in November 2012

Favourable

- Lower finance charges, primarily due to higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion and the impact of the conversion of the Corporation's US$40 million convertible debentures into common shares in November 2011. The above decreases were partially offset by higher interest on credit facility borrowings, due to higher average credit facility borrowings, and higher fees associated with the increase in the Corporation's credit facility to $1 billion in May 2012.

REGULATORY HIGHLIGHTS

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

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2011	2012	2013	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	BCUC	40 (1)	9.50	9.50	9.50 (1)	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40 (1)	10.00	10.00	10.00 (1)	ROEs established by the BCUC – 2013 ROEs are under review
FEWI	BCUC	40 (1)	10.00	10.00	10.00 (1)	Future test year
FortisBC Electric	BCUC	40 (1)	9.90	9.90	9.90 (1)	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC – 2013 ROE is under review Future test year
FortisAlberta	AUC	41 (1)	8.75	8.75	8.75 (1)	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account ROE established by the AUC – 2013 ROE is under review 2012 test year for 2013 through 2017
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45 (1)	8.38 +/– 50 bps	8.80 +/– 50 bps	8.80 (1) +/– 50 bps	COS/ROE The allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. The formula was suspended for 2012 and 2013 ROE is under review Future test year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future test year
FortisOntario	OEB					
	Canadian Niagara Power	40	8.01	8.01	8.93 (2)	Canadian Niagara Power – COS/ROE
	Algoma Power	40	9.85	9.85	9.85 (2)	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Franchise Agreement					Cornwall Electric – Price cap with commodity cost flow through
	Cornwall Electric					Canadian Niagara Power – 2009 test year for 2011 and 2012; 2013 test year for 2013 Algoma Power – 2011 test year for 2011, 2012 and 2013
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A		ROA		COS/ROA
			7.75 – 9.75	7.25 – 9.25	7.25 – 9.25 (3)	Rate-cap adjustment mechanism ("RCAM") based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical test year
Fortis Turks and Caicos	Utilities make annual filings to the Government of the Turks and Caicos Islands	N/A	17.50 (4)	17.50 (4)	17.50 (4)	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the utilities may apply for an increase in customer rates in the following year. Future test year

(1) Capital structures and allowed ROEs for 2013 are interim and are subject to change based on the outcomes in 2013 of cost of capital proceedings

(2) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 8.93% for 2013. This ROE is not applicable to the regulated electric utilities until they are scheduled to file full COS rate applications. As a result, the allowed ROE of 8.93% is not applicable to Algoma Power in 2013.

(3) Subject to change in June 2013 based on the annual operation of the RCAM

(4) Amount provided under licences as it relates to FortisTCI and Atlantic. Amount provided under licence for TCU is 15%. Achieved ROAs at the utilities were significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• In July 2011 FEVI received a BCUC decision approving the options of two First Nations, the Stz'uminus First Nation and the Cowichan Tribes, to invest up to a combined 15% in the equity component of the capital structure of the LNG storage facility on Vancouver Island. In late 2011 each band exercised its option and each invested approximately $6 million in equity in the LNG storage facility on January 1, 2012. • In August 2011 FEI received a BCUC decision on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for natural gas-fuelled vehicles ("NGVs"). FEI had made these funds available to assist large customers in purchasing NGVs in lieu of vehicles fuelled by diesel. The decision determined that it was not appropriate to use EEC funds for the above-noted purpose and the BCUC requested that FEI provide at a future time further submissions to determine the prudency of the EEC incentives. In August 2012 an application was filed with the BCUC to review the prudency of the EEC incentives totalling approximately $6 million. A decision is expected in the first half of 2013. • Effective January 1, 2012, rates for typical residential customers in the Lower Mainland increased by approximately 3%, reflecting changes in delivery and midstream costs. • Effective April 1, 2012, due to a decrease in natural gas commodity costs, rates for residential customers in the Lower Mainland decreased by approximately 10% and rates for residential customers at FEWI decreased by approximately 6%. • In April 2012 the BCUC issued its decision on the FortisBC Energy companies' 2012/2013 Revenue Requirements Application ("RRA"). The interim increases in customer delivery rates, effective January 1, 2012, at FEI and FEWI reflected the applied for rate increases. The final approved increase in customer delivery rates, effective January 1, 2012, was 4.2% at FEI, approximately 1.4% lower than the interim customer delivery rates. The final approved increase in customer delivery rates, effective January 1, 2012, was 3.6% at FEWI, approximately 1.4% lower than the interim customer delivery rates. In its decision, the BCUC approved FEVI's 2012 and 2013 customer rates to remain unchanged from 2011 customer rates. Differences between interim and final customer rates at FEI and FEWI were refunded to customers in 2012 commencing June 1, 2012. The final approved customer delivery rates for 2012 and 2013 reflected allowed ROEs and capital structure unchanged from 2011, pending the outcome of the GCOC Proceeding as it may impact 2013 rates. The cumulative impacts of the 2012/2013 revenue requirements decision, where such impacts were different from those estimated, were recorded in the second quarter of 2012. The final rate increases were driven by ongoing investment in energy infrastructure focused on system integrity and reliability, forecasted increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas system, and increasing compliance with codes and regulations. • In February 2012 the BCUC approved FEI's amended application for a general tariff for the provision of compressed natural gas ("CNG") and LNG refuelling services for transportation vehicles. FEI has received either permanent or interim rate approval for three such refuelling projects. FEI's application for changing its LNG sales and dispensing service rate schedule from a pilot program to a permanent program is pending before the BCUC. A decision on the application is expected in the first half of 2013. • In April 2012 the FortisBC Energy companies applied to the BCUC for the necessary approvals to amalgamate the three utilities and implement postage stamp rates across the service territories served by the amalgamated entity, effective January 1, 2014. The evidentiary portion of the proceeding was closed in October 2012 and a decision was received in February 2013. In its decision, the BCUC denied the request to implement postage stamp rates and, as a result, the FortisBC Energy companies will not be proceeding with an amalgamation. • Following the announcement by the Government of British Columbia of the *Greenhouse Gas Reductions (Clean Energy) Regulation* ("GHG Regulation") under the *Clean Energy Act*, which was promulgated in May 2012, FEI announced an incentive funding program to assist eligible vehicle operators in purchasing LNG-fuelled vehicles. The incentive program funding includes up to $62 million, over a period of several years, to offset a percentage of the incremental capital cost for eligible operators in purchasing qualifying LNG-fuelled vehicles. The eligible applicants for the incentive program are commercial return-to-base fleet operators of heavy-duty trucks, buses, other vocational vehicles and marine vessels. Awarding of the incentives commenced in late 2012 and will cover up to 75% of the eligible operators' incremental capital costs. Additionally, the GHG Regulation allows FEI to invest up to $30 million for LNG fuelling stations and up to $12 million for CNG fuelling stations. In October 2012 the BCUC approved the rate treatment of the above expenditures being made under the GHG Regulation. • In December 2012 the BCUC issued its decision regarding the BCUC-initiated public process, which commenced in May 2011, inquiring into whether FEI should be able to provide alternative energy services as regulated utility services and to establish guidelines that would apply to the provision of such services. The BCUC determined that CNG and LNG refuelling services are regulated when they are provided by a public utility such as FEI. However, the BCUC recommended that FEI undertake such services in the future through a separate non-regulated affiliate, with the exception of expenditures permitted under the GHG Regulation. Similarly, the BCUC determined that biomethane services are part of FEI's regulated service offering, but that ownership of any biogas upgrading systems will be determined on a case by case basis. Moreover, district energy systems and other geo-exchange systems are regulated and should continue to be carried out through FEI's affiliate, FAES, although an exemption from regulation can be sought for discrete energy systems. FEI is considering the findings of the decision and its impact on its provision of these services.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In November 2011 the BCUC issued preliminary notification to public utilities subject to its regulation, including the FortisBC gas and electric utilities, that it would initiate a GCOC Proceeding in early 2012. In February 2012 the BCUC established that a GCOC Proceeding would occur and, in April 2012, issued a final scoping document outlining specific items to be reviewed as part of the GCOC Proceeding, which included: (i) the appropriate cost of capital for a benchmark low-risk utility, effective January 1, 2013, which includes capital structure, ROE and interest on debt; (ii) the establishment of a benchmark ROE based on a benchmark low-risk utility effective from January 1, 2013 through December 31, 2013 for the initial transition year; (iii) the determination of whether a return to an ROE automatic adjustment mechanism is warranted, which would be implemented January 1, 2014 or, if not warranted, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013; (iv) a generic methodology on how to establish each utility's cost of capital in reference to the cost of capital for a benchmark low-risk utility; (v) a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt; and (vi) for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism and, if not warranted, a future regulatory process will be set on how the deemed interest rate would be adjusted beyond December 31, 2013. The BCUC has also determined that a second, subsequent phase be added to the GCOC Proceeding to determine an appropriate allowed ROE and capital structure for all other regulated utilities in British Columbia once the benchmark utility has been established in the first phase of the GCOC Proceeding. FEI has been designated as the benchmark utility. FEVI, FEWI and FortisBC Electric will have their allowed ROEs and capital structures determined in the second phase of the GCOC Proceeding. The public oral hearing for the first phase of the GCOC Proceeding occurred in December 2012. A decision on the benchmark utility, FEI, is expected mid-2013. Effective January 1, 2013, as ordered by the BCUC in December 2012, the current allowed ROE and capital structure for FEI and all other regulated entities in British Columbia that rely on the benchmark utility to establish rates are to be maintained and made interim. The results of the GCOC Proceeding could materially impact the earnings of the FortisBC Energy companies and FortisBC Electric. • FAES has filed applications for approval of several thermal-energy projects. These projects and their status are as follows: (i) Delta School District – approval has been granted by the BCUC; (ii) Tsawwassen Springs Development – approval has been granted by the BCUC; (iii) PCI Marine Gateway – approval has been granted by the BCUC for the capital expenditures, but approval of revisions to the rate design and rates is pending; (iv) Telus Garden – approval has been granted by the BCUC for the capital expenditures, but approval of revisions to the rate design and rates is pending; and (v) Kelowna District Energy System – the regulatory process is ongoing and a BCUC decision is expected in the second quarter of 2013.
FortisBC Electric	• In August 2012 the BCUC issued its decision on FortisBC Electric's 2012/2013 RRA, its 2012/2013 Capital Expenditure Plan and its Integrated System Plan ("ISP"). The ISP included the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand-Side Management Plan. The resulting final revenue requirements for 2012 and 2013 reflect an allowed ROE and capital structure unchanged from 2011, pending the outcome of the GCOC Proceeding as it may impact 2013 rates. The decision included an approved forecasted midyear rate base of approximately $1,112 million for 2012 and $1,173 million for 2013. In its decision the BCUC approved deferral accounts and flow-through treatment for variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates; however, flow-through treatment for finance charges was denied. FortisBC Electric requested, and the BCUC approved, that the interim refundable 1.5% increase in customer rates, effective January 1, 2012, as approved by the BCUC in November 2011, be maintained for the remainder of 2012. The difference between the final approved increase in 2012 customer rates of 0.6% and the interim increase in customer rates of 1.5% was approved for deferral as a regulatory liability in 2012, to be used in 2013 to reduce the increase in customer rates to 4.2%, effective January 1, 2013. The rate increases were due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. • In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion and submitted the agreement to the BCUC. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010. In May 2012 the BCUC determined that the executed agreement was in the public interest and a hearing was not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA. • In March 2012 the BCUC issued an order establishing a written hearing process to review the prudency of approximately $29 million in capital expenditures already incurred related to the Kettle Valley Distribution Source Project, which was substantially completed in 2009. FortisBC Electric believes that the capital expenditures were prudently incurred and, therefore, cannot reasonably determine if any of such expenditures may be permanently disallowed from rate base and any resulting financial impact. The written hearing process was completed in 2012 and a BCUC decision is pending. • In July 2012 FortisBC Electric filed its Advanced Metering Infrastructure ("AMI") Application, which is currently under regulatory review by the BCUC and various interveners. The AMI project proposes to improve and modernize FortisBC Electric's grid by exchanging its manually read meters with advanced meters. The AMI project is expected to cost approximately $48 million and be completed in 2015. Pending the outcome of FortisBC Electric's offer to purchase the City of Kelowna's electrical utility assets, as discussed further below, FortisBC Electric has filed a conditional amendment to the AMI Application for approximately $4 million in incremental AMI capital expenditures.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisBC Electric (cont'd)	• In November 2012 FortisBC Electric filed an application with the BCUC requesting approval for FortisBC Electric to acquire the City of Kelowna's electrical utility assets, which currently serve some 15,000 customers, for approximately $55 million and to include the assets in FortisBC Electric's rate base. FortisBC Electric provides the City of Kelowna with electricity under a wholesale tariff and has operated and maintained the City of Kelowna's electrical utility assets under contract since 2000. In March 2013 the BCUC approved the transaction and determined the value of the assets for inclusion in FortisBC Electric's rate base to be approximately $38 million. FortisBC Electric is considering whether to proceed with the transaction and must confirm its acceptance of the conditions of the BCUC approval by March 31, 2013.
FortisAlberta	• In December 2011 the AUC issued its decision on its 2011 GCOC Proceeding, establishing the allowed ROE at 8.75% for 2011 and 2012 and, on an interim basis, at 8.75% for 2013. The deemed equity component of FortisAlberta's capital structure remained at 41%. In addition, the AUC concluded that it would not return to a formula-based allowed ROE automatic adjustment mechanism. In the decision, the AUC also made statements regarding cost responsibility for stranded assets, which FortisAlberta and other utilities challenged as being incorrectly made. As a result, FortisAlberta and the other utilities filed a Review and Variance ("R&V") Application with the AUC. In June 2012 the AUC decided it would not permit an R&V of the decision in question, but would examine the issue in the Utility Asset Disposition ("UAD") Proceeding, which was reinitiated in November 2012. FortisAlberta and the other utilities had also sought leave to appeal the stranded asset pronouncements to the Alberta Court of Appeal and have temporarily adjourned that court process pending the AUC's follow-up proceeding. FortisAlberta is fully participating in the UAD Proceeding and common-utility evidence has been filed and experts have been engaged. The UAD Proceeding is expected to continue through the first quarter of 2013 with a decision expected by the second quarter of 2013. Any decision by the AUC regarding the treatment of stranded assets does not alter a utility's right to a reasonable opportunity to recover prudent COS and the right to earn a reasonable ROE. • In March 2012 the AUC issued a bulletin regarding maintaining regulated electricity rates. The bulletin addressed the Government of Alberta's letter requesting that regulated electricity rates be maintained until the Government of Alberta responds to the recommendations of the Retail Market Review Committee ("Committee") announced in February 2012. The Committee's mandate included the review of the default electricity rate charged to customers who do not obtain retail service from a retailer. The AUC continued processing applications before them and could approve applications that maintained existing rates or proposed rate reductions; however, the AUC did not issue decisions that resulted in rate increases. The Committee's recommendations were provided to the Alberta Minister of Energy for review in September 2012. In January 2013 the Government of Alberta responded to the recommendations of the Committee and, as part of that response, requested that the AUC begin the process to remove the electricity rate increase limitations that have been in effect since February 2012. • In April 2012 the AUC approved, substantially as filed, a Negotiated Settlement Agreement ("NSA") pertaining to FortisAlberta's 2012 distribution revenue requirements, resulting in an average increase in customer distribution rates of approximately 5%, effective January 1, 2012, consistent with the interim rate increase that was previously approved by the AUC in December 2011. The cumulative impacts of the 2012 revenue requirements decision, where such impacts were different from those estimated, were recorded in the second quarter of 2012. The increase in customer rates was driven primarily by ongoing investment in energy infrastructure, including increased financing costs. The NSA provided for forecasted midyear rate base of $2,025 million for 2012. The AUC did not approve the continuation of the deferral of transmission volume variances associated with FortisAlberta's AESO charges deferral account for 2012. The deferral of transmission volume variances, however, was reinstated, effective January 1, 2013, per the AUC's PBR Decision, as discussed further below. • In June 2012 AESO filed with the AUC a Customer Contribution Policy Application and an Amortized Construction Contribution Rider I Application. The first application proposed a reduction in the level of AESO contributions that transmission customers, including FortisAlberta, would pay versus what the transmission facility owner would pay. The second application proposed that transmission customers be given the option to make the required AESO contributions as a series of payments over a number of years, rather than as an upfront payment. Effectively, this would result in the transmission facility owner financing the AESO contributions. In December 2012 the AUC issued a decision that denied both applications and directed AESO to bring forward its proposals as part of its next comprehensive AESO tariff application. As a result, the current contribution policy and the manner in which contributions are paid remain in effect. • In July 2012 the AUC issued a decision denying an application filed by the Central Alberta Rural Electrification Association ("CAREA") in which CAREA had requested, effective January 1, 2012, that it be entitled to serve any new customers wishing to obtain electricity for use on property overlapping CAREA's service area and that FortisAlberta be restricted to providing service in the overlapping CAREA service area to only those customers who are not being provided service by CAREA. The decision confirmed that FortisAlberta is the primary electricity distribution service provider within its service territory, including that portion of the Company's service territory that overlaps CAREA's service territory. CAREA did not seek leave to appeal the decision and the time limit to appeal has expired. • In September 2012 the AUC issued a generic PBR Decision outlining the PBR framework applicable to distribution utilities in Alberta, including FortisAlberta, for a five-year term, which commenced January 1, 2013. In the PBR Decision, a formula that estimates inflation annually and assumes productivity improvements is to be used by the distribution utilities to determine customer rates on an annual basis. The PBR Decision raises some concern and uncertainty for FortisAlberta regarding the treatment of certain capital expenditures. While the PBR Decision did provide for a capital tracker mechanism for the recovery of certain capital expenditures, FortisAlberta sought further clarification regarding this mechanism in its required Compliance Application filed in November 2012 and an R&V Application. FortisAlberta has also sought leave to appeal the issue to the Alberta Court of Appeal. In December 2012 FortisAlberta filed a 2013 Capital Tracker Application with the AUC for specific categories of capital expenditures. • In December 2012 the AUC issued a decision setting 2012 customer distribution rates as interim rates for 2013, pending the AUC's decisions on FortisAlberta's Compliance and Capital Tracker Applications.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In March 2013 the AUC issued decisions approving, on an interim basis, the Compliance Application substantially as filed and denying the R&V Application. In the Compliance Decision, the AUC approved the requested 1.71% increase in customer distribution rates, effective January 1, 2013, reflecting the determination of the inflationary and productivity factors in accordance with the PBR Decision. The AUC also approved the requested customer distribution rate adjustments for flow-through costs. Given the volume of information included in the 2013 Capital Tracker Applications filed by the distribution utilities in Alberta, and the complexity and materiality of the issues involved, the AUC approved the utilities to recover, on an interim basis, 60% of the revenue requirement associated with the 2013 capital tracker expenditures applied for. For FortisAlberta, the AUC approved, therefore, approximately $14.5 million of the $24 million in revenue requested in its 2013 Capital Tracker Application. Final decisions on the 2013 Capital Tracker Applications are not expected until later in 2013. FortisAlberta filed a required second Compliance Application in March 2013, containing updated rate schedules subject to AUC approval for customer bills beginning on April 1, 2013, with a final decision expected later in 2013. • In October 2012 the AUC initiated a GCOC Proceeding, which includes the determination of: (i) the allowed ROE for 2013; (ii) whether a formulaic ROE automatic mechanism should be re-established; and (iii) whether the PBR Decision or other decisions require the adjustment of the allowed ROE or equity component of total capital structure as a result of any changes in risk. The AUC recently suspended the GCOC Proceeding, pending the outcomes of various PBR-related applications and the UAD Proceeding. The GCOC Proceeding is expected to commence later in 2013.
Newfoundland Power	• In March 2012 Newfoundland Power filed a Cost of Capital Application with the PUB to discontinue the use of the current ROE automatic adjustment mechanism and to approve a just and reasonable rate of return on average rate base for 2012. In June 2012 the PUB ordered that the allowed ROE for 2012 be increased to 8.80% from 8.38% for 2011. The PUB also approved the deferred recovery from customers of approximately $2.5 million before tax, representing the difference between the 8.38% allowed ROE reflected in customer electricity rates in 2012 and the final approved allowed ROE of 8.80%. • In October 2012 the PUB approved Newfoundland Power's 2013 Capital Expenditure Plan totalling approximately $82 million, before customer contributions. • Effective July 1, 2012, the PUB approved an overall average increase in Newfoundland Power's customer electricity rates of 6.6%. The increase in rates was primarily the result of the normal annual operation of Newfoundland Hydro's Rate Stabilization Plan. Variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to customers through the operation of Newfoundland Power's Rate Stabilization Account ("RSA"). The operation of the RSA further captures variances in certain of Newfoundland Power's costs, such as pension and energy supply costs. The above-noted increase in customer rates did not impact Newfoundland Power's earnings in 2012. • In September 2012 Newfoundland Power filed a 2013/2014 General Rate Application for the purpose of setting customer electricity rates and cost of capital. Newfoundland Power is proposing an overall average increase in customer electricity rates of 6%, effective March 1, 2013. The Company is also proposing the discontinuance of the ROE automatic adjustment formula. A public hearing on the application concluded in February 2013.
Maritime Electric	• In February 2012 the PEI Commission released its Discussion Paper, *Charting Our Electricity Future,* which outlined discussion points on which the PEI Commission should seek input through a consultative process with stakeholders and the general public. Maritime Electric participated in public forums and stakeholder consultations held in early 2012. In January 2013 the PEI Commission released a Final Report of its recommendations to the Government of PEI, which included the following: (i) Maritime Electric should continue as PEI's primary electric utility; however, the PEI Energy Corporation should acquire Maritime Electric's generation assets over a reasonable period of time, thereby reducing the utility's rate base and equity; (ii) the equity component of Maritime Electric's capital structure should be maintained at no less than 35% and no more than 40% of total capital structure; (iii) the current COS regulatory model should be maintained but responsibility for the *Electric Power Act* (PEI) should be assigned to a new three-person panel of commissioners that deals only with electric utility regulation and oversight and will operate independently of IRAC; (iv) a consumer advocate for electricity should be appointed to better facilitate the participation of interested parties at regulatory hearings; (v) the Government of PEI should assume the responsibility for financing the existing $47.5 million of deferred incremental replacement energy costs at Maritime Electric associated with the refurbishment of the New Brunswick Power ("NB Power") Point Lepreau nuclear generating station ("Point Lepreau"); (vi) a new cable interconnection with New Brunswick should be pursued immediately and ownership of the cable should reside with the Government of PEI; and (vii) responsibility for demand-side management programming, currently with the Government of PEI, should transfer back to Maritime Electric. • In March 2012 Maritime Electric received regulatory approval to defer, for refund to customers in a future period to be determined, income tax expense reductions associated with the Company's amendment of corporate income tax filings for the years 2007 through 2010. The amended filings seek to expense certain costs previously capitalized for income tax purposes. • In December 2012 the *Accord Continuation Act* was enacted, which sets out the inputs, rates and other terms for the continuation of the PEI Energy Accord ("Accord") for an additional three years covering the period March 1, 2013 through February 29, 2016. Over the three-year period, increases in electricity costs for a typical residential customer have been set at 2.2% annually and Maritime Electric's allowed ROE has been capped at 9.75% each year. Under the terms of the *Accord Continuation Act* and the Accord, the Government of PEI assumed, effective March 1, 2011, responsibility for the cost of incremental replacement energy and monthly operating and maintenance costs related to Point Lepreau during its refurbishment period, which ended in fall 2012. • In December 2012 Maritime Electric's 2013 Capital Budget Application totalling approximately $26 million, before customer contributions, was approved as filed, with the exception of approximately $1 million related to preparatory work for a third submarine-cable interconnection, which has been deferred for additional consideration by IRAC.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation IRM as prescribed by the OEB. In the first quarter of 2012, the OEB published applicable inflationary and efficiency targets, resulting in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne, effective May 1, 2012. The Third-Generation IRM maintained the allowed ROE at 8.01% for 2012. • In April 2012 the OEB issued Final Decisions and Orders for customer rates effective May 1, 2012 at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. The result was an average 3.1% decrease in residential customer rates in Fort Erie; an average 0.6% increase in residential customer rates in Gananoque; and an average 4.6% decrease in residential customer rates in Port Colborne. The above-noted rate changes were mainly due to changes in rate riders associated with regulatory deferral accounts and smart meter funding. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the then-current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constituted the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase transaction was approved by the OEB in March 2012 and closed on April 16, 2012. • In March 2012 the OEB issued its decision on Algoma Power's Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The decision approved a price-cap index of 2.81% for customers subject to RRRP funding and 0.38% for those customers not subject to RRRP funding. RRRP funding for 2012 was set at approximately $11 million. Algoma Power's allowed ROE was maintained at 9.85% for 2012. • In May 2012 FortisOntario filed a COS Application for electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The application proposed an allowed ROE of 9.12% on a deemed equity component of capital structure of 40%. In addition to an updated COS, the application included the integration of smart meter costs into rate base, the recovery of stranded assets related to conventional meters and a rate rider designed to capture additional smart meter expenditures forecasted to the end of 2012. In September 2012 an NSA on the COS Application was reached, which was approved in November 2012, as filed, and the allowed ROE for 2013, as determined under the ROE automatic adjustment formula, was calculated at 8.93%, down from the 9.12% that was estimated in the COS Application. In November 2012 the OEB also determined that most of a $1 million income tax-related regulatory deferral is not required to be dispersed to customers. The result of the above decisions, including the impact of the decrease in the allowed ROE, effective January 1, 2013, was an average 6.8% increase in residential customer rates in Fort Erie; an average 5.9% increase in residential customer rates in Gananoque; and an average 7.4% increase in residential customer rates in Port Colborne. • In October 2012 Algoma Power filed a Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2013. The application was prepared in a manner consistent with the OEB's decision on the utility's 2012 rate application; however, the 2013 rate application has been complicated by the requirement to dispose of smart meter costs. Since distribution rates for Algoma Power's residential customers are governed by separate regulation, recovery of smart meter investments will impact the determination of RRRP funding for 2013. The OEB has scheduled a written hearing for the application. • In December 2012 the OEB issued an order making Algoma Power's customer rates for 2012 interim rates for 2013, until a final rate order is issued on 2013 customer rates.
Caribbean Utilities	• In April 2012 the ERA approved Caribbean Utilities' 2012–2016 Capital Investment Plan ("CIP") for US$122 million of non-generation installation capital expenditures. The 2012–2016 CIP was prepared in line with the Certificate of Need that was filed with the ERA in November 2011. Proposals for installation of new generation units from six qualified bidders, including Caribbean Utilities, was requested by the ERA and Caribbean Utilities' proposal was submitted in July 2012. In February 2013 the ERA awarded the bid to develop, install and operate two new 18-MW generation units to a third party. Caribbean Utilities will enter into negotiations leading to a long-term PPA with the third party. • The proposed 2013–2017 CIP, totalling approximately US$125 million of non-generation installation capital expenditures, was submitted to the ERA in October 2012 for approval. • In March 2012 the ERA approved the creation of Caribbean Utilities' wholly owned subsidiary DataLink Ltd. ("DataLink"). Subsequently, the Information and Communications Technology Authority ("ICTA") granted a 15-year licence to DataLink expiring in March 2027 to provide fibre-optic infrastructure and other information and communication technology services on Grand Cayman. The ICTA licence allows DataLink to assume full responsibility for the existing pole-attachment agreements and optical fibre lease agreement held by Caribbean Utilities with third-party information and communications technology service providers. The reassignment of existing contracts was completed in 2012. The ERA has approved the executed management and maintenance, pole-attachment and fibre-optic agreements between Caribbean Utilities and DataLink. • In August 2011 the Company initiated a competitive bidding process to fill 13 MW of non-firm renewable energy capacity. Extensive negotiations with two leading bidders have been conducted. The proposals considered are two 5-MW solar photovoltaic power plants and one 3-MW small-scale wind turbine project. An agreement has been reached with one bidder on the significant terms and milestones leading to the execution of a binding PPA, subject to regulatory approval. Caribbean Utilities anticipates agreeing to terms on a similar basis with the second bidder in the first half of 2013. Pursuant to these agreements, Caribbean Utilities anticipates purchasing renewable energy at competitive prices from large-scale renewable energy facilities by late 2014. • Effective June 1, 2012, following review and approval by the ERA, Caribbean Utilities' base customer electricity rates increased by 0.7% as a result of changes in the applicable consumer price indices and the utility's achieved ROA for 2011.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Fortis Turks and Caicos	• In February 2012 the Interim Government of the Turks and Caicos Islands ("Interim Government") approved an approximate 26% increase in electricity rates, effective April 1, 2012, for FortisTCI's large hotel customers. In addition, other qualitative enhancements to the franchise were also achieved, including: (i) improved wording in the *Electricity Rate Regulation*; (ii) an approved increase in kilowatt hour consumption thresholds for both medium- and large-sized hotels; (iii) an expansion of service territory to cover all of the Turks and Caicos Islands, except for areas currently serviced by private suppliers' licences, with new 25-year licences issued for the expanded service territory; and (iv) the discontinuance of the government subsidization of the utility's South Caicos operations. • In April 2012 FortisTCI entered into a Streetlight Takeover Agreement with the Interim Government, whereby the responsibility for the ownership, installation and maintenance of all streetlights in the utility's service territory was transferred to FortisTCI. • An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the Interim Government. FortisTCI provided a comprehensive response to the Interim Government in January 2012 stating that the Company supports limited mutually agreed upon reforms, but that its current licences must be respected and can only be changed by mutual consent. Specifically, FortisTCI would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. Negotiations between FortisTCI and the Interim Government occurred during the third quarter of 2012, with FortisTCI presenting a new regulatory framework proposal to the Interim Government. A third-party consultant was engaged by the Interim Government to review the proposal and provide recommendations. No agreement was reached with the Interim Government; however, management expects to continue dialogue on regulatory reform with the newly elected government. • In March 2013 the Fortis Turks and Caicos utilities submitted their 2012 annual regulatory filings outlining performance in 2012. Included in the filings were the calculations, in accordance with the utilities' licences, of rate base of US$195 million for 2012 and cumulative shortfall in achieving allowable profits of US$105 million as at December 31, 2012.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2012 and December 31, 2011.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2012 and December 31, 2011

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Cash and cash equivalents	67	The increase was primarily due to cash on hand at FortisAlberta as a result of the Company's $125 million debt offering in October 2012.
Accounts receivable	(51)	The decrease was primarily due to: (i) the FortisBC Energy companies, due to lower commodity cost of natural gas reflected in customer rates and lower sales volumes as a result of warmer temperatures; and (ii) FortisAlberta, as a result of decreased rate riders and a change in the billing of retailers from a monthly to a weekly basis.
Regulatory assets – current and long-term	82	The increase was mainly due to: (i) higher regulatory deferred income taxes; (ii) higher regulatory deferred employee future benefit costs, driven by Newfoundland Power; and (iii) an increase in the deferral of various other costs, as permitted by the regulators, mainly at the FortisBC Energy companies. The increase was partially offset by: (i) approximately $76 million associated with the deferral of the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; and (ii) the collection of approximately $44 million of the AESO charges deferral account at FortisAlberta.
Utility capital assets	605	The increase primarily related to $1,053 million invested in electricity and gas systems, partially offset by depreciation and customer contributions during 2012.
Income producing properties	32	The increase primarily related to $35 million in capital expenditures and the acquisition of the StationPark Hotel in October 2012 for approximately $13 million, partially offset by depreciation for 2012.
Accounts payable and other current liabilities	(11)	The decrease was mainly due to: (i) the $76 million change in the fair market value of natural gas derivatives at the FortisBC Energy companies; (ii) lower amounts owing for purchased natural gas at the FortisBC Energy companies, due to lower volumes; and (iii) lower accounts payable at the Waneta Partnership associated with the timing of payments related to the construction of the Waneta Expansion. The above decreases were partially offset by higher accounts payable associated with transmission-connected projects and timing of AESO payments for transmission costs at FortisAlberta, and the reclassification of income tax liabilities associated with Part VI.1 taxes from long-term other liabilities.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2012 and December 31, 2011 (cont'd)

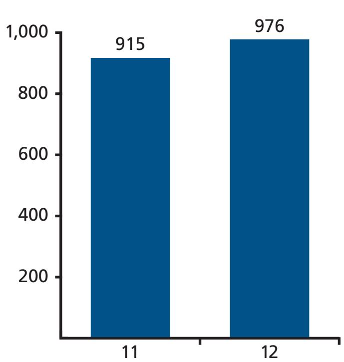
Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Regulatory liabilities – current and long-term	90	The increase was mainly due to an increase in the AESO charges deferral at FortisAlberta and an overall increase in regulatory liabilities at the FortisBC Energy companies. The increase at the FortisBC Energy companies was mainly due to: (i) the provisioning for non-ARO removal costs commencing January 1, 2012; (ii) an increase in the Revenue Surplus Deferral Account, reflecting amounts collected in customer rates in excess of the cost of providing service at FEVI in 2012; and (iii) an increase in the Midstream Cost Reconciliation Account, as amounts collected in customer rates were in excess of actual midstream gas-delivery costs in 2012.
Other liabilities	58	The increase was primarily due to higher defined benefit pension and OPEB liabilities as a result of actuarial losses recognized due to lower discount rates as at December 31, 2012, partially offset by the reclassification of income tax liabilities associated with Part VI.1 taxes to current liabilities.
Deferred income tax liabilities – current and long-term	44	The increase was driven by tax timing differences related mainly to capital expenditures at the regulated utilities.
Long-term debt (including current portion)	112	The increase was primarily due to: (i) $125 million 40-year 3.98% unsecured debentures issued by FortisAlberta in October 2012, largely in support of its capital expenditure program; and (ii) higher committed credit facility borrowings at the Corporation, FortisBC Electric and Newfoundland Power, partially offset by the repayment of committed credit facility borrowings at FortisAlberta. The above increases were partially offset by regularly scheduled debt repayments at Fortis Properties, Caribbean Utilities, FortisBC Electric and the FortisBC Energy companies.
Shareholders' equity	365	The increase was driven by the $200 million preference share offering in November 2012. The remainder of the increase was primarily due to net earnings attributable to common equity shareholders in 2012, less common share dividends, and the issuance of common shares mainly under the Corporation's dividend reinvestment and stock option plans.
Non-controlling interests	102	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership and an approximate $12 million, or 15%, equity investment by two First Nations bands in the LNG storage facility on Vancouver Island.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2012 compared to 2011, followed by a discussion of the nature of the variances in cash flows year over year.

Cash Flow from Operating Activities
($ millions)



Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	2012	2011	Variance
Cash, Beginning of Year	**87**	107	(20)
Cash Provided by (Used in):			
Operating Activities	**976**	915	61
Investing Activities	**(1,080)**	(1,115)	35
Financing Activities	**171**	180	(9)
Cash, End of Year	**154**	87	67

Operating Activities: Cash flow from operating activities in 2012 was $61 million higher than in 2011. The increase was primarily due to higher earnings and the collection from customers of regulator-approved increased depreciation and amortization, partially offset by unfavourable changes in working capital. The unfavourable changes in working capital were associated with inventories, accounts payable and other current liabilities, and current regulatory deferral accounts, partially offset by favourable changes in accounts receivable.

Investing Activities: Cash used in investing activities in 2012 was $35 million lower than in 2011. The decrease was mainly due to: (i) a $52 million deferred payment made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002, which increased cash used in investing activities in 2011; (ii) a decrease in capital spending; and (iii) a decrease in cash used in business acquisitions. The decrease in capital spending was mainly due to the completion of the Customer Care Enhancement Project at FEI in early 2012, a delay in capital spending in 2012 at FortisBC Electric, due to the timing of receipt of approval for its 2012/2013 revenue requirements, and the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. The above decreases in capital spending were partially offset by higher capital spending at FortisAlberta, due to the connection of new customers, driven by strong economic growth in Alberta, and increased capital spending related to the Waneta Expansion. The decrease in cash used in business acquisitions was the result of the acquisition of the Hilton Suites Hotel in October 2011 for $25 million compared to: (i) the acquisition of the StationPark Hotel in October 2012 for $7 million, net of debt assumed; (ii) the acquisition of TCU in August 2012 for $8 million (US$8 million), net of debt assumed; and (iii) the acquisition of electricity distribution assets from the City of Port Colborne in April 2012 for $7 million. The above decreases in cash used in investing activities were partially offset by lower proceeds from the sale of utility capital assets. In October 2011 Newfoundland Power sold joint-use poles and related infrastructure to Bell Aliant for $45 million, net of costs.

Financing Activities: Cash provided by financing activities in 2012 was $9 million lower than in 2011. The decrease was mainly due to: (i) lower proceeds from the issuance of common shares; (ii) lower proceeds from long-term debt; (iii) higher repayments of long-term debt; (iv) higher common share dividends; and (v) costs related to the issuance of Subscription Receipts in June 2012. The above items were partially offset by: (i) higher net borrowings under committed credit facilities classified as long term; (ii) proceeds from the issuance of preference shares in November 2012; (iii) lower net repayments of short-term borrowings; and (iv) higher advances from non-controlling interests in the Waneta Partnership.

Net repayments of short-term borrowings were $22 million in 2012 compared to $198 million in 2011. The decrease in the repayments of short-term borrowings was driven by the FortisBC Energy companies, Maritime Electric and Caribbean Utilities.

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 2012 compared to 2011, are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2012**	2011	Variance
FortisBC Energy Companies	–	100 (1)	(100)
FortisAlberta	**124** (2)	123 (3)	1
Maritime Electric	–	30 (4)	(30)
FortisOntario	–	52 (5)	(52)
Caribbean Utilities	–	38 (6)	(38)
Total	**124**	343	(219)

(1) Issued December 2011, 30-year $100 million 4.25% unsecured debentures by FEI. The net proceeds were used to repay short-term credit facility borrowings.

(2) Issued October 2012, 40-year $125 million 3.98% unsecured debentures. The net proceeds are being used to repay committed credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

(3) Issued October 2011, 30-year $125 million 4.54% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(4) Issued December 2011, 50-year $30 million 4.915% secured first mortgage bonds. The net proceeds were used to repay short-term credit facility borrowings.

(5) Issued December 2011, 30-year $52 million 5.118% unsecured notes. The net proceeds were used to repay intercompany borrowings with Fortis originally incurred to support the acquisition of Algoma Power in 2009.

(6) Issued 15-year US$15 million 4.85% and 20-year US$25 million 5.10% unsecured notes. The first tranche of US$30 million was issued in June 2011 and the second tranche of US$10 million was issued in July 2011. The net proceeds were used to repay current installments on long-term debt and short-term credit facility borrowings and to finance capital expenditures.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31 *($ millions)*	**2012**	2011	Variance
FortisBC Energy Companies	**(20)**	(4)	(16)
FortisBC Electric	**(16)**	–	(16)
Newfoundland Power	**(5)**	(5)	–
Caribbean Utilities	**(16)**	(15)	(1)
Fortis Properties	**(28)**	(8)	(20)
Other	**(3)**	(8)	5
Total	**(88)**	(40)	(48)

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	**2012**	2011	Variance
FortisAlberta	**(29)**	6	(35)
FortisBC Electric	**26**	9	17
Newfoundland Power	**22**	5	17
Corporate	**52**	(165)	217
Total	**71**	(145)	216

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.

Advances of approximately $93 million for 2012 and $84 million for 2011 were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion.

In November 2012 Fortis completed a $200 million public offering of 8 million First Preference Shares, Series J. The net proceeds of approximately $194 million were used to repay borrowings under the Corporation's committed corporate credit facility, which borrowings were primarily incurred to support the construction of the Waneta Expansion and for other general corporate purposes.

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of approximately $300 million. In July 2011 an additional 1.24 million common shares were publicly issued upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million. The total net proceeds of $327 million from the common share offering were largely used to repay borrowings under credit facilities, support the construction of the Waneta Expansion and for other general corporate purposes.

Fortis also received proceeds of $24 million in 2012 and $18 million in 2011, net of dividends reinvested into common shares, related to common shares issued under its stock option and share purchase plans.

Common share dividends paid in 2012 totalled $170 million, net of $58 million of dividends reinvested, compared to $151 million, net of $59 million of dividends reinvested, paid in 2011. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.20 in 2012 compared to $1.16 in 2011. The weighted average number of common shares outstanding was 190.0 million for 2012 compared to 181.6 million for 2011.

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 December 31, 2012, are outlined in the following table.

Contractual Obligations

As at December 31, 2012 *($ 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	**5,900**	117	690	187	291	81	4,534
Government loan obligations (1)	**29**	4	10	10	5	–	–
Capital lease and finance obligations (2)	**2,593**	48	49	49	50	52	2,345
Interest obligations on long-term debt	**6,682**	355	344	311	297	271	5,104
Gas purchase contract obligations (3)	**249**	207	42	–	–	–	–
Power purchase obligations							
FortisBC Electric (4)	**34**	13	7	6	5	3	–
FortisOntario (5)	**360**	48	49	50	52	53	108
Maritime Electric (6)	**140**	38	40	40	8	1	13
Capital cost (7)	**446**	17	18	18	18	17	358
Operating lease obligations (8)	**26**	5	4	3	3	3	8
Waneta Partnership promissory note (9)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (10)	**62**	4	3	3	3	3	46
Defined benefit pension funding contributions (11)	**82**	38	16	12	12	1	3
Performance Share Unit ("PSU") Plan obligations (12)	**6**	2	2	2	–	–	–
Other (13)	**7**	2	1	–	–	–	4
Total	**16,688**	898	1,275	691	744	485	12,595

(1) In prior years, FEVI received non-interest bearing repayable loans from the Canadian federal government and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government debt financing, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure.

(2) Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's Brilliant PPA and Brilliant Terminal Station.

(3) Gas purchase contract obligations include various gas purchase contracts at the FortisBC Energy companies and are based on market prices that vary with gas commodity indices. The obligations include the gross cash payments associated with the FortisBC Energy companies' natural gas commodity derivatives. The amounts disclosed reflect index prices that were in effect as at December 31, 2012.

(4) Power purchase obligations for FortisBC Electric are comprised of a PPA with BC Hydro, a capacity agreement with Powerex Corp. ("Powerex") and a capacity and energy purchase agreement with Brilliant Expansion Power Corporation ("Brilliant Corporation").

The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

In 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. The capacity being purchased under the agreement does not relate to a specific plant.

In November 2012 FortisBC Electric entered into an agreement to purchase capacity and energy from January 2013 through to December 2017 from CPC acting on behalf of Brilliant Corporation. The agreement was accepted by the BCUC in December 2012.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount expected to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing was not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA. The amount associated with the WECA has not been included in the Contractual Obligations table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

(5) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(6) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(7) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(8) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases.

(9) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $47 million as at December 31, 2012.

(10) FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2017 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time.

FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. FortisAlberta has provided the necessary notice to terminate the shared-service agreements effective December 31, 2013.

(11) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2012 and 2013 – FortisBC Energy companies (plans covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (plan covering unionized employees)
December 31, 2013 – FortisBC Electric
December 31, 2014 – Newfoundland Power

The estimate of defined benefit pension funding contributions includes the impact of the outcome of the December 31, 2011 actuarial valuation, completed in April 2012, associated with the defined benefit pension plan at Newfoundland Power. As a result of the valuation, Newfoundland Power is required to fund a solvency deficiency of approximately $53 million, including interest, over five years beginning in 2012, which is reflected in the Contractual Obligations table above. The Company fulfilled its 2012 annual solvency deficit funding requirement during the second quarter of 2012. The increase in funding contributions is expected to be recovered from customers in future rates.

[12] The settlement of PSUs outstanding as at December 31, 2012, which were granted in each of 2010, 2011 and 2012, are subject to the President and Chief Executive Officer of Fortis satisfying certain payment requirements over the three-year vesting periods.

The Corporation's $6 million liability related to outstanding Deferred Share Units as at December 31, 2012 has been excluded from the Contractual Obligations table above, as the timing of the payments is indeterminable at this time.

[13] Other contractual obligations include building operating leases, AROs, fuel option contracts at Caribbean Utilities and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecasted to be approximately $1.3 billion for 2013. Over the five years 2013 through 2017, the Corporation's consolidated capital expenditure program, including capital expenditures at Central Hudson, is expected to total $6 billion, which has not been included in the Contractual Obligations table above.

Pending Acquisitions: As detailed in the "Significant Items – Pending Acquisition of CH Energy Group" section of this MD&A, in February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group. The agreement and plan of merger may be terminated by the Corporation or CH Energy Group at any time prior to closing in certain circumstances, including if the acquisition has not closed by February 20, 2013, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to August 20, 2013. In February 2013 the date was extended to August 20, 2013.

FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets for $55 million, as detailed in the "Regulatory Highlights – Material Regulatory Decisions and Applications" section of this MD&A.

Subscription Receipts Offering: To finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18.5 million Subscription Receipts at $32.50 each in June 2012, realizing gross proceeds of approximately $601 million. For further information on the Subscription Receipts offering, refer to the "Significant Items – Subscription Receipts Offering" section of this MD&A.

Other: In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes LNG storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest. The non-controlling interests hold put options which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under each of the contracts for the operation of Caribbean Utilities' diesel-powered generating plant. The approximate combined quantities under the contracts, expressed in millions of imperial gallons, on an annual basis by fiscal year are: 2013 – 32.4 and 2014 – 18.9. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $681 million as at December 31, 2012 have been excluded from the Contractual Obligations table above, as the final timing of the settlement of many of the liabilities is subject to a further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 7 to the 2012 Annual Consolidated Financial Statements.

The FortisBC Energy companies have issued commitments to customers to provide EEC funding under the respective program approved by the BCUC. As at December 31, 2012, approximately $5 million of funding had been committed to customers.

Capital Structure

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis as at December 31, 2012 compared to December 31, 2011 is presented in the following table.

Capital Structure

	2012		2011	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**6,317**	**55.3**	6,296	57.1
Preference shares	**1,108**	**9.7**	912	8.3
Common shareholders' equity	**3,992**	**35.0**	3,823	34.6
Total [(2)]	**11,417**	**100.0**	11,031	100.0

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

[(2)] Excludes amounts related to non-controlling interests

The improvement in the capital structure was primarily due to: (i) the First Preference Shares, Series J offering in November 2012 for net proceeds of approximately $194 million, which were used to repay borrowings under the Corporation's committed corporate credit facility; (ii) common shares issued under the Corporation's dividend reinvestment and stock option plans; (iii) net earnings attributable to common equity shareholders, net of dividends; and (iv) an increase in cash. The capital structure was also impacted by an increase in long-term debt, largely in support of energy infrastructure investment.

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2012 was 53.6% debt, 10.1% preference shares and 36.3% common shareholders' equity (December 31, 2011 – 55.3% debt, 8.6% preference shares and 36.1% common shareholders' equity).

Credit Ratings

As at December 31, 2012, the Corporation's credit ratings were as follows:

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

In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget, S&P and DBRS also removed the ratings from 'credit watch with negative implications' and 'under review with developing implications', respectively, where the ratings had been placed in February 2012.

The above-noted credit ratings reflect the Corporation's business-risk profile and the diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

Capital Expenditure Program

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $103 million in maintenance and repairs was expensed in 2012 compared to approximately $98 million in 2011.

Gross consolidated capital expenditures for 2012 were approximately $1.1 billion. A breakdown of gross consolidated capital expenditures by segment and asset category for 2012 is provided in the following table.

Gross Consolidated Capital Expenditures [1]

Year Ended December 31, 2012

($ millions)	FortisBC Energy Companies	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	Total Regulated Utilities – Canadian	Regulated Electric Utilities – Caribbean	Non-Regulated – Fortis Generation	Fortis Properties	Total
Generation	–	–	8	9	1	**18**	**21**	**196**	**–**	**235**
Transmission	46	–	19	6	4	**75**	**–**	**–**	**–**	**75**
Distribution	113	318	26	62	38	**557**	**20**	**–**	**–**	**577**
Facilities, equipment, vehicles and other	32	108	11	5	2	**158**	**6**	**–**	**35**	**199**
Information technology	15	16	5	4	3	**43**	**1**	**–**	**–**	**44**
Total	206	442	69	86	48	**851**	**48**	**196**	**35**	**1,130**

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

Gross consolidated capital expenditures of $1,130 million for 2012 were $161 million lower than $1,291 million forecasted for 2012, as disclosed in the MD&A for the year ended December 31, 2011. 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 forecasts. Lower-than-forecasted capital spending was mainly due to: (i) a shift in capital expenditures from 2012 to 2013 related to the timing of payments associated with the Waneta Expansion; (ii) a delay in capital spending at FortisBC Electric and the FortisBC Energy companies in 2012, due to the timing of receipt of regulatory approvals for their 2012/2013 revenue requirements; and (iii) timing of capital spending associated with the construction of Fortis Properties' office building in St. John's, Newfoundland. The above decreases were partially offset by higher-than-forecasted capital spending at FortisAlberta, due to higher spending associated with customers in the oil and gas sectors and capital expenditures associated with a distribution control centre, partially offset by lower-than-forecasted AESO transmission-related capital expenditures.

Gross consolidated capital expenditures for 2013 are expected to be approximately $1.3 billion. A breakdown of forecasted gross consolidated capital expenditures by segment and asset category for 2013 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [1]

Year Ending December 31, 2013

($ millions)	FortisBC Energy Companies	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	Total Regulated Utilities – Canadian	Regulated Electric Utilities – Caribbean	Non-Regulated – Fortis Generation	Fortis Properties and Other [2]	Total
Generation	–	–	3	5	2	**10**	**20**	**229**	**–**	**259**
Transmission	41	–	33	7	7	**88**	**–**	**–**	**–**	**88**
Distribution	119	351	44	64	39	**617**	**18**	**–**	**–**	**635**
Facilities, equipment, vehicles and other	49	65	48	5	4	**171**	**9**	**–**	**113**	**293**
Information technology	20	21	5	5	2	**53**	**2**	**–**	**–**	**55**
Total	229	437	133	86	54	**939**	**49**	**229**	**113**	**1,330**

[1] Relates to forecasted cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes forecasted capitalized depreciation and amortization and non-cash equity component of AFUDC.

[2] Includes forecasted capital expenditures of approximately $70 million at Fortis Properties, and approximately $43 million at FAES, which is included in the Corporate and Other segment. For further information, refer to the "Regulatory Highlights – Material Regulatory Decisions and Applications" section of this MD&A.

The percentage breakdown of 2012 actual and 2013 forecasted gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31 (%)	Actual 2012	Forecasted 2013
Growth	**43**	41
Sustaining [1]	**35**	33
Other [2]	**22**	26
Total	**100**	100

[1] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

[2] Relates to facilities, equipment, vehicles, information technology systems and other assets, including AESO transmission-related capital expenditures at FortisAlberta

Management Discussion and Analysis

Over the five-year period 2013 through 2017, gross consolidated capital expenditures, including expenditures at Central Hudson, are expected to be approximately $6 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 55% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 19% at Canadian Regulated Gas Utilities; 11% at Central Hudson; 4% at Caribbean Regulated Electric Utilities; and the remaining 11% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 36% to meet customer growth; 41% for sustaining capital expenditures; and 23% for facilities, equipment, vehicles, information technology and other assets.

Forecasted 2013 midyear rate base for the Corporation's four large Canadian regulated utilities is provided in the following table.

Forecast Midyear Rate Base

($ billions)	**2013**
FortisBC Energy Companies	**3.7**
FortisAlberta	**2.3**
FortisBC Electric	**1.2**
Newfoundland Power	**0.9**

Central Hudson's midyear rate base for 2013 is expected to be almost $1 billion.

Significant capital projects for 2012 and 2013 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) **Company**	**Nature of Project**	Pre-2012	**Actual 2012**	Forecasted 2013	Forecasted Post-2013	Expected Year of Completion
FortisBC Energy Companies	Customer Care Enhancement Project	80	**30**	–	–	2012
FortisAlberta	Pole-Management Program	88	**27**	29	183	2019
FortisBC Electric	Environmental Compliance Project	2	**4**	18	4	2014
Waneta Partnership	Waneta Expansion [(2)]	244	**192**	227	172	2015
FortisProperties	Office Building – St. John's	8	**12**	24	3	2013/2014

(1) Relates to utility capital asset, income producing property and intangible asset expenditures combined with both the capitalized interest and equity components of AFUDC, where applicable

(2) Excludes forecasted capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

FEI's Customer Care Enhancement Project came into service at the beginning of 2012 at a total project cost of approximately $110 million. The project entailed the insourcing of core elements of FEI's customer care services, including two Company-owned call centres and billing operations, and implementation of a new customer information system.

During 2012 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program, which involves approximately 110,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through to 2019 is now expected to be approximately $327 million compared to $335 million forecasted as at December 31, 2011. Approximately $27 million was spent on this program in 2012.

The Environmental Compliance Project at FortisBC Electric relates to work required to ensure compliance of the utility's substation equipment with the *Canadian Environmental Protection Act PCB Regulations* by 2014. The project has been approved by the regulator and is estimated to cost approximately $28 million through to 2014. Approximately $6 million has been spent on this project to the end of 2012.

Construction progress on the $900 million, 335-MW Waneta Expansion, in partnership with CPC/CBT, is going well and the project is currently on schedule and on budget. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Major construction activities on-site during 2012 included the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $436 million in total has been spent on the Waneta Expansion since construction began in late 2010, with $192 million spent in 2012. Approximately $227 million is expected to be spent in 2013, with key project activities including completion of the powerhouse structural steel and building envelope; excavation of the intake approach channel; construction of the intake and tailrace structures; and removal of rock plug. In addition, installation of the stationary imbedded turbine and generator components will continue.

The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC Electric under a long-term capacity purchase agreement. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table above, includes capitalized interest of Fortis during construction and a $72 million payment expected to be made in 2020 related to certain intangible assets and project design costs previously incurred by CPC/CBT. The table above excludes forecasted capitalized interest of the minority partners in the Waneta Partnership.

Fortis Properties is constructing a 12-storey office building in downtown St. John's, Newfoundland at an estimated cost of approximately $47 million. Approximately $20 million has been spent on this project to the end of 2012. Construction is expected to be completed by the end of 2013 or in early 2014.

Other less significant capital projects forecasted for 2013 include several thermal energy projects at FAES and various natural gas transportation initiatives at the FortisBC Energy companies.

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 2013 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be $117 million in 2013 and to average approximately $273 million annually over the next five years. 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. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

In May 2012 Fortis filed a base shelf prospectus under which Fortis may offer, from time to time during the 25-month period from May 10, 2012, by way of a prospectus supplement, common shares, preference shares, subscription receipts and/or unsecured debentures in the aggregate amount of up to $1.3 billion (or the equivalent in US dollars or other currencies). The base shelf prospectus provides the Corporation with flexibility to access securities markets in a timely manner. The nature, size and timing of any offering of securities under the Corporation's base shelf prospectus will be consistent with the past capital-raising practices of the Corporation and continue to be dependent upon the Corporation's assessment of its requirements for funding and general market conditions.

To finance a portion of the Corporation's pending acquisition of CH Energy Group, Fortis offered and sold, by way of a prospectus supplement, approximately $601 million in Subscription Receipts under a bought-deal offering with a syndicate of underwriters. Fortis also closed an offering of approximately $200 million First Preference Shares, Series J by way of a prospectus supplement under the above-noted base shelf prospectus.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis or Abitibi and was approximately $54 million as at December 31, 2012 (December 31, 2011 – $56 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For a further discussion of the Exploits Partnership, refer to the "Key Trends, Risks and Opportunities – Expropriated Assets" section of this MD&A.

Except for the debt at the Exploits Partnership, as described above, Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2012 and are expected to remain compliant in 2013.

Credit Facilities

As at December 31, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.5 billion, of which approximately $2.1 billion was unused, including $946 million unused under the Corporation's $1 billion committed corporate credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.3 billion of the total credit facilities are committed facilities with maturities ranging from 2013 through 2017.

The cost of renewed and extended credit facilities may increase depending on market conditions; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2013.

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

Credit Facilities

($ millions)	Regulated Utilities	Fortis Properties	Corporate and Other	**Total as at December 31, 2012**	Total as at December 31, 2011
Total credit facilities	1,402	13	1,045	**2,460**	2,248
Credit facilities utilized:					
Short-term borrowings	(136)	–	–	**(136)**	(159)
Long-term debt (including current portion)	(97)	–	(53)	**(150)**	(74)
Letters of credit outstanding	(66)	–	(1)	**(67)**	(66)
Credit facilities unused	1,103	13	991	**2,107**	1,949

As at December 31, 2012 and 2011, 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.

Significant changes in total credit facilities from December 31, 2011 to December 31, 2012 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2012 are detailed in Note 33 to the Corporation's 2012 Audited Consolidated Financial Statements.

In March 2012 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from August 2015 to August 2017. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2012 FortisBC Electric renegotiated and amended its credit facility agreement, resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility, with $50 million now maturing in May 2013 and $100 million now maturing in May 2015. The amended credit facility agreement otherwise contains substantially similar terms and conditions as the previous credit facility agreement.

In May 2012 FHI extended its $30 million unsecured committed revolving credit facility to mature in May 2013 from May 2012. The new agreement contains substantially similar terms and conditions as the previous credit facility agreement.

In May 2012 Fortis increased the amount available for borrowing under its unsecured committed revolving corporate credit facility from $800 million to $1 billion, as permitted under the credit facility agreement.

In May 2012 Caribbean Utilities renegotiated and increased the amount available for borrowing under its unsecured credit facilities to US$47 million from US$33 million.

In June 2012 FortisOntario entered into a new unsecured revolving credit facility agreement for $30 million maturing in June 2013, replacing two credit facilities totalling $20 million. The new credit facility agreement reflects a decrease in pricing and improved terms and conditions. In July 2012 the former credit facilities were terminated.

In July 2012 FEI entered into a one-year extension of its $500 million unsecured committed revolving credit facility, extending the maturity date from August 2013 to August 2014. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In July 2012 FortisAlberta renegotiated and amended its $250 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from September 2015 to August 2016. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $67 million, as at December 31, 2012 (December 31, 2011 – $66 million), the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to regulation, primarily COS regulation, that can affect future revenue and earnings. Management at each utility is responsible for working closely with its regulator and local government to ensure both compliance with existing regulations and the proactive management of regulatory issues.

The utilities are subject to the normal uncertainties faced by regulated entities, including approval by the respective regulatory authority of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, the continuation of licences. Generally, the ability of a utility to recover the actual COS and to earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting process. Upgrades of, and additions to, gas and electricity infrastructure require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS.

There is no assurance that capital expenditures perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital expenditure overruns subject to such approvals might not be recoverable in customer rates.

Changes in tax legislation and/or accounting rules may also have the effect of reducing the utilities' rate base, thereby reducing the utilities' future customer rates and potential earnings.

Through the regulatory process, regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth.

Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

A failure to obtain rates, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of proposed capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

The utilities may also be subject to financial penalties imposed by the regulators, including those related to contravening a regulatory order, rule or standard, and/or performing below established service quality thresholds, which penalties could adversely affect the utilities' results of operations and/or cash flows where such penalties are not recoverable from customers.

Approximately 93% of the Corporation's operating revenue[(1)] was derived from regulated utility operations in 2012 (2011 – 93%), while approximately 90% of the Corporation's operating earnings[(2)] were derived from regulated utility operations in 2012 (2011 – 89%). Regulated utility assets comprised approximately 90% of total assets of Fortis as at December 31, 2012 (December 31, 2011 – 91%). Fortis considers the regulatory frameworks in North America to be fair and balanced. There is, however, a concentration of regulatory risk in British Columbia, with 55% of the Corporation's regulated assets under the jurisdiction of the BCUC. The risk is heightened by a significant regulatory calendar for FortisBC's gas and electricity businesses. The FortisBC utilities will be busy in 2013 with various filings, interrogatories, inquiries and/or hearings, including those related to the GCOC Proceeding and submission of RRAs for the gas and electricity businesses in 2013.

FEI, FEVI, FEWI and FortisBC Electric are regulated by the BCUC and have used PBR mechanisms from time to time to establish customer rates. PBR mechanisms provide a utility with the incentive to achieve greater efficiencies and cost savings, which can lead to improved earnings. The PBR mechanism at FortisBC Electric expired at the end of 2011 and the PBR mechanism at FEI expired at the end of 2009, with a two-year phase-out to the end of 2011. Upon expiry of PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be.

The transition to PBR at FortisAlberta, effective January 1, 2013, and the use of a formula to establish customer rates raises some concern and uncertainty for FortisAlberta regarding how PBR will be applied in practice. As part of the PBR Decision, distribution utilities in Alberta will file for annual rate adjustments in accordance with the formula prescribed. There are uncertainties regarding how various components of FortisAlberta's costs will be addressed by the formula and other PBR mechanisms. While the PBR Decision provided a capital tracker mechanism to address the recovery of certain capital expenditures outside of the PBR formula, that mechanism has yet to be tested to confirm its applicability to FortisAlberta's capital programs. In response to the uncertainties, FortisAlberta is working in conjunction with the other distribution utilities in Alberta to ensure this change in regulation is compliant with the statutory requirements of the *Electric Utilities Act* (Alberta) ("EUA").

With PBR, the AUC has also signalled that it has a preference for formula-based rate-making and generic proceedings. While generic proceedings allow for regulatory efficiencies, there is the risk of a tendency of favouring a collective result regardless of individual utility circumstances.

As an owner of an electricity distribution network under the EUA, FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act as a regulated-rate provider or default supplier, FortisAlberta would be required, under the EUA, to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

The use of automatic adjustment mechanisms to annually calculate allowed ROEs was introduced in Canada in the mid to late 1990s, with the goal of providing efficiency in the regulatory process by reducing the frequency of cost of capital reviews. Generally, the mechanisms used a formula that calculated an annual adjustment to allowed ROEs based upon changes in long-term Canada bond rates. As long-term Canada bond rates declined, the use of ROE automatic adjustment mechanisms came under increased scrutiny in many jurisdictions in Canada because they failed to produce allowed ROEs that were high enough to meet the fair return standard. The regulatory decisions received by the Corporation in 2009 regarding cost of capital reviews in British Columbia and Alberta resulted in the elimination of the ROE automatic adjustment mechanism for FortisBC's gas and electric utilities and the suspension of the mechanism at FortisAlberta. The suspension of the automatic adjustment mechanism was continued in Alberta for 2011 and 2012, with an allowed ROE ordered by the AUC of 8.75% for these years, and for 2013 on an interim basis. The AUC has initiated a GCOC Proceeding, which is expected to commence later in 2013, to finalize, among other things, the allowed ROE and capital structure for 2013 and consider whether a return to a formula-based approach is warranted. A GCOC Proceeding commenced in British Columbia in early 2012 to review, among other things, cost of capital effective January 1, 2013 and whether the re-establishment of an ROE automatic adjustment mechanism is warranted. The ROE automatic adjustment mechanism was suspended for Newfoundland Power for 2012 and cost of capital was reviewed with the allowed ROE set at 8.80% for 2012. Cost of capital for 2013 is being reviewed in conjunction with Newfoundland Power's 2013/2014 General Rate Application. Newfoundland Power has requested in its application that the ROE automatic adjustment mechanism be discontinued.

(1) Operating revenue is a non-GAAP measure and refers to total revenue excluding Corporate and Other segment revenue and inter-segment eliminations.

(2) Operating earnings is a non-GAAP measure and refers to net earnings attributable to common equity shareholders excluding Corporate and Other segment net loss.

For a sensitivity analysis of the impact on earnings for 2013 of changes in the allowed ROEs and capital structure for each of the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power, refer to each of the "Outlook" sections in the "Segmented Results of Operations" section in this MD&A.

In 2012 the OEB updated its consultation process on Renewed Regulatory Framework for Electricity Distribution. The new framework is expected to utilize a more comprehensive PBR approach to regulation, which also provides rate-setting alternatives that can be adapted to individual utility circumstances. Three alternative rate-setting methods will be available to distributors going forward and each distributor will be expected to select the method that best meets its needs and circumstances and apply to the OEB to have rates set on that basis. FortisOntario will continue to closely monitor these new rate-making methods to determine which best fits its requirements, with the goal of maximizing long-term regulatory and operating performance.

For additional information on the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues.

Completion of the Acquisition of CH Energy Group: The acquisition of CH Energy Group remains subject to NYSPSC approval. A delay in receiving the approval, and/or conditions imposed under such approval, may result in the failure to materialize some, or all, of the expected benefits of the acquisition of CH Energy Group or such benefits may not occur within the time periods anticipated by the Corporation. The realization of such benefits may also be impacted by other factors beyond the control of Fortis.

The agreement and plan of merger may be terminated by the Corporation or CH Energy Group at any time prior to closing, in certain circumstances, including if the acquisition has not closed by February 20, 2013, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to August 20, 2013. In February 2013 the date was extended to August 20, 2013.

A portion of the acquisition purchase price is expected to be funded by approximately $601 million of escrowed proceeds from the Corporation's June 2012 Subscription Receipts offering. If conditions precedent to the closing of the transaction are not fulfilled or waived, including receipt of NYSPSC approval, by June 30, 2013, or if the agreement and plan of merger related to the acquisition is terminated prior to such time, the proceeds from the Subscription Receipts offering, plus *pro rata* interest earned, are required to be returned to the holders of such receipts. As a result, closing of the transaction subsequent to June 30, 2013 could result in the Corporation having to raise alternative capital to finance the acquisition.

Also, additional acquisition-related expenses to be incurred in 2013 could be higher than those anticipated. Examples of expenses expected to be incurred include investment bank merger and acquisition advisory fees and consulting and legal fees.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory determined or negotiated process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and what effect it may have on allowed ROEs of the Corporation's regulated utilities. A significant decline in interest rates and resulting impact on allowed ROEs could adversely affect the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may result in a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under floating-rate credit facilities and the refinancing of long-term debt. At the FortisBC Energy companies, interest expense variances from forecast for rate-setting purposes related to short-term and long-term interest rates and the timing of long-term debt issuances are recovered through future rates using regulatory deferral mechanisms approved by the BCUC to the end of 2013. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions and orders. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rate on, long-term debt are different from those forecasted and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through to customers interest costs could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, 80% of the Corporation's consolidated long-term debt as at December 31, 2012 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2012.

Total Debt

As at December 31, 2012	*($ millions)*	*(%)*
Short-term borrowings	**136**	**2.2**
Utilized variable-rate credit facilities classified as long-term	**150**	**2.5**
Variable-rate long-term debt (including current portion)	**5**	**0.1**
Fixed-rate long-term debt (including current portion)	**5,745**	**95.2**
Total	**6,036**	**100.0**

In October 2012 FortisAlberta issued 40-year 3.98% $125 million unsecured debentures and in 2011 long-term debt was issued at various of the Corporation's regulated utilities at rates ranging from 4.25% to 5.118% and with terms ranging from 15 to 50 years, demonstrating the ability of the utilities to raise long-term capital at attractive rates.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2012, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions leading to lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery. The FortisBC Energy companies are exposed to various operational risks such as: pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability. The business of electricity T&D is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. The FortisBC utilities operate in a remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. The FortisBC Energy companies, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions, other natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through higher customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that should be made to maintain and replace the assets. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material adverse effect on the financial position and results of operations of the Corporation's utilities.

Generally, the Corporation's utilities have designed their natural gas and electricity systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely distribute gas and electricity, which could have a material adverse effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to COS and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any additional costs will receive regulatory approval for recovery in future customer rates. It is generally expected, however, that prudently incurred costs can be recovered in customer rates. The inability to recover additional costs, however, could have a material adverse effect on the utilities' financial position and results of operations. See also the "Business Risk Management – Regulatory Risk" section of this MD&A.

Economic Conditions: Typical of utilities, energy sales in the Corporation's service territories are influenced by economic factors, such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. Also, the FortisBC Energy companies are affected by the trend in housing starts from single-family dwellings to multi-family dwellings. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, growth in gas distribution volumes may be tempered.

Generally, higher energy prices can result in reduced consumption by customers. However, natural gas and crude oil exploration and production activities are closely correlated with natural gas and crude oil prices. The level of these activities, which tend to increase with increased energy prices, can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities' performance despite regulatory measures available to compensate for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending, which would, in turn, affect rate base and earnings growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region continues to be impacted by weak economic conditions that are expected to continue into 2013 and possibly 2014. Assets of Caribbean Regulated Electric Utilities comprise approximately 6% of the Corporation's total assets. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand. Some limited economic growth is anticipated on Grand Cayman with the construction of the first phase of Health City Cayman Islands (Dr. Shetty Hospital) and the boost to air arrivals capacity with the introduction of a new airline service to the Cayman Islands late summer 2012. The Turks and Caicos Islands' economy is also showing some growth, mainly in the tourism sector. The recent announcement by the Government of the Turks and Caicos Islands that the second phase of the airport development project will proceed is a positive development, which may provide some economic growth going forward.

Due to weak economic conditions in the Caribbean, combined with the impact on customer bills of high fuel prices, electricity sales growth at Caribbean Regulated Electric Utilities is projected to be 2% to 3% in 2013, excluding sales from TCU, which was acquired in August 2012; however, projected sales growth is not as high as that experienced prior to 2009.

Fortis also holds investments in both commercial office and retail space and hotel properties, with these assets combined representing 4% of the Corporation's total assets. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Approximately 57% of Fortis Properties' operating income was derived from hotel investments in 2012 (2011 – 56%). The Canadian hospitality industry, while recovering from the economic downturn, is doing so at a very slow rate. Fortis Properties' Hospitality Division continues to face uncertainty, particularly in central Canada, where the Ontario economy remains challenged. The Canadian commercial real estate industry continued to be strong in 2012, with occupancy levels stable and rental rates trending upward in select markets. Fortis Properties' real estate exposure to lease expiries averages approximately 9% per annum over the next five years. While there is some opportunity for rate growth on lease renewals, high occupancies and long-term leases, particularly in the Maritime provinces, may limit organic growth in Fortis Properties' Real Estate Division. Most rate growth expected in this Division will be driven by increasing rates in St. John's as a result of strong market conditions. Vacancy rates in the Company's New Brunswick and rural Newfoundland real estate operations, due to weak local market conditions, will present challenges. It is estimated that a 10% decrease in revenue in Fortis Properties' Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Project Budget Overrun, Completion and Financing Risk in the Corporation's Non-Regulated Business: In its non-regulated business, Fortis generally bears the risk of budget overruns on capital projects, including increased costs associated with higher financing expense, schedule delays and lower-than-expected performance. In contrast, these budget overruns, when incurred prudently in the regulated business, can generally be recovered in customer rates as part of COS. Budgets for capital projects are established, in part, on estimates that are subject to a number of assumptions, including future economic conditions; productivity and performance of employees, contractors, subcontractors or equipment suppliers; price and availability of labour, equipment and materials; and other requirements that may affect project costs or schedules, such as obtaining the required environmental permits, licences and approvals on a timely basis. The risk of cost overruns is mitigated by contractual approach, regular and proactive monitoring by employees with appropriate expertise and regular review by senior management. Cost overruns and delays in project completion may also occur when unforeseen circumstances arise. The cost of financing large capital projects is subject to conditions experienced in the capital markets that may result in higher financing costs than originally estimated. The construction of the non-regulated Waneta Expansion is currently on schedule and on budget and, to date, minimal contingency amounts have been used.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or its larger subsidiaries fail 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 results of operations and the financial position of the Corporation and the subsidiaries; the regulatory environment in which the utilities operate and the nature and outcome of regulatory decisions regarding capital structure and allowed ROE; conditions in the capital and bank credit markets; ratings assigned by credit rating agencies; and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Despite the volatility that has occurred in the global capital markets in recent years, the Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Volatility in the global capital markets may have the effect of increasing the cost, and affecting the timing of issuance, of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. As at December 31, 2012, Fortis had approximately $2.5 billion in consolidated credit facilities, of which $2.3 billion is committed with maturities ranging from 2013 through 2017. Approximately $2.1 billion of the consolidated credit facilities was unused as at December 31, 2012. Approximately $54 million was drawn on the committed corporate credit facility at as December 31, 2012.

The cost of renewed and extended credit facilities could increase going forward; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2013. Due to their regulated nature, any forecasted changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates. Various credit facilities were renegotiated, amended or extended in 2012, including an increase in the amount available for borrowing under the committed corporate credit facility from $800 million to $1 billion under the terms of the existing credit facility agreement. The $1 billion committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial recession placed increased scrutiny on rating agencies and rating agency criteria, which has affected credit rating practices and policies.

There were no changes in the utilities' credit ratings in 2012. In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget, S&P and DBRS also removed the ratings from 'credit watch with negative implications' and 'under review with developing implications', respectively, where the ratings had been placed in February 2012.

Further information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

Expropriation of Shares in Belize Electricity: In 2008 the newly elected GOB changed the electricity rate-setting methodology in Belize to one that did not allow Belize Electricity to recover its reasonable COS and make a reasonable rate of return on its investment as required by law and, thereby, it is the Corporation's position that the GOB has breached covenants that the GOB made when it sold its shares in Belize Electricity to Fortis in 1999. Relying on the new rate-setting methodology, the Belize Public Utilities Commission denied Belize Electricity a customer rate increase in its June 2008 Final Decision and subsequently amended that decision to decrease customer rates by 15%, notwithstanding the fact that a rate increase was required to adequately finance the utility's operations. The GOB further compounded Belize Electricity's financial problems when it increased the utility's business tax from 1.75% to 6.5%, effective in 2010. Due to an increase in the cost of purchased power, higher business taxes and the above-noted denial of compensatory customer rates, Belize Electricity required short-term financial assistance from the GOB in spring 2011. The GOB chose to prepay some of its electricity bills as the preferred alternative of financial assistance from the options proposed by Belize Electricity, which allowed the utility to meet its power purchase obligations with the Mexican state-owned Comision Federal de Electricidad ("CFE") to the end of June 2011, after which time Belize Electricity would have been able to source most of its energy power requirements from lower-cost local hydroelectric generating facilities, coinciding with the commencement of the rainy season in Belize, rather than from the CFE.

On June 20, 2011, the GOB enacted in one day the *Electricity (Amendment) Act 2011* ("*Acquisition Act*") and the *Electricity (Assumption of Control over Belize Electricity Limited) Order 2011* ("*Acquisition Order*") to expropriate the Corporation's majority ownership investment in Belize Electricity but did not expropriate any of the minority ownership investments, which continue to be held by the Social Security Board of Belize and Belizean residents. The purported public purpose stated in the *Acquisition Order*, as the basis of the decision to expropriate Belize Electricity, was "*to maintain an uninterrupted and reliable supply of electricity to the public*". The Corporation's evidence is that there was no risk of interruption or unreliable electricity supply at the time of expropriation and, while Belize Electricity had financial difficulties in 2011, such difficulties were caused by the GOB and, therefore, the GOB cannot rely on a situation it created to justify expropriating Belize Electricity.

Four days after expropriation of the Corporation's investment in Belize Electricity, the Belize Court of Appeal delivered its judgment that a similar expropriation of control of Belize Telemedia Limited ("Belize Telemedia"), a public telecommunications provider in Belize, in 2009 was unconstitutional, null and void. Rather than accept and appeal the judgment, the GOB enacted revised expropriation legislation to retain control of Belize Telemedia and contemporaneously proposed a constitutional amendment, the purported effect of which was to: (i) declare the GOB's ownership of three specifically identified public utility providers, including Belize Electricity and Belize Telemedia; (ii) deem the expropriation of Belize Electricity and re-expropriation of Belize Telemedia to have been done for a public purpose; and (iii) oust the jurisdiction of the Belize Courts to review the GOB expropriation actions.

On October 21, 2011, Fortis filed a claim ("Claim No. 673 of 2011") in the Belize Supreme Court challenging the GOB's expropriation of the Corporation's investment in Belize Electricity pursuant to the *Acquisition Act* and *Acquisition Order*. On October 25, 2011, the *Belize Constitution* (*Eighth Amendment*) *Act 2011* ("*Eighth Amendment*") was enacted to validate and immunize the GOB's expropriation of Belize Electricity and Belize Telemedia. As a consequence of the above, Fortis subsequently amended its Claim No. 673 of 2011 to additionally challenge the constitutionality of the *Eighth Amendment*.

On June 11, 2012, the trial division of the Belize Supreme Court delivered its judgment in the claims of *British Caribbean Bank Limited v Attorney General et al* ("Claim No. 597 of 2011") and *Dean Boyce v Attorney General et al* ("Claim No. 646 of 2011") (collectively the "Telemedia Judgment") regarding the purported re-expropriation of Belize Telemedia. The court determined that the re-expropriation of the Claimants' properties by the GOB in those claims was unconstitutional, null and void. The judge determined most of the *Eighth Amendment* to be invalid, but found that he could sever those portions of sections 143 and 144 of the *Eighth Amendment* which declare GOB ownership of the named utilities, and that the severance thereby prevented the judge from ordering divestiture of the GOB's control of Belize Telemedia and hence the judge found himself precluded by the Belize Constitution from granting the Claimants the consequential relief sought.

Hearing of the Corporation's Claim No. 673 of 2011 occurred on July 2, 2012 before the same judge who delivered the Telemedia Judgment. The judge believed he was bound by his reasons in the Telemedia Judgment and dismissed the Corporation's Claim No. 673 of 2011 on the grounds that the severed portions of the *Eighth Amendment* precluded divestiture of the GOB's ownership and control of Belize Electricity, notwithstanding the *Acquisition Act* and *Acquisition Order*, which are virtually identical to the provisions of the 2009 expropriation of Belize Telemedia, and were found to be invalid by the Belize Court of Appeal. The judge, therefore, denied the relief sought by Fortis.

On July 5, 2012, Fortis filed its appeal of the above-noted July 2, 2012 trial judgment to the Belize Court of Appeal. The Belize Court of Appeal allowed an application for consolidation of the Corporation's appeal with the appeal and cross-appeal of the Telemedia Judgment, and directed that the appeals be heard on an expedited basis commencing October 8, 2012.

Management Discussion and Analysis

In its appeal, Fortis submitted that the *Acquisition Act* violates the Belize Constitution and should be struck down as: (i) the *Acquisition Act* does not prescribe the principles and manner in which reasonable compensation is to be determined in a reasonable time; (ii) the *Acquisition Act* does not prescribe the principles and manner in which reasonable compensation is to be given in a reasonable time; (iii) the *Acquisition Act* does not provide a right of access to the Belize Court for the purpose of enforcing a right to compensation; and (iv) certain sections of the *Acquisition Act* violate certain sections of the Belize Constitution. Fortis also submitted that the *Acquisition Order* violates the Corporation's constitutional rights and should be struck down as: (i) it is not proportionate; (ii) the expropriation of Belize Electricity by the GOB was arbitrary as the GOB did not acquire the minority shareholdings of the Social Security Board or Belizean nationals in Belize Electricity and is, therefore, in violation of the Belize Constitution; and (iii) Fortis was not afforded a right to be heard by the Belize Minister of Public Utilities before its property was compulsorily acquired by the GOB. Fortis also contends that the application of saved portions of sections 143 and 144 of the *Eighth Amendment* are also invalid and should not have precluded the ordering of consequential relief to Fortis for several reasons, including the fact that such provisions are void as they: (i) deprive the Belize Court of jurisdiction to conduct the constitutionally mandated inquiry to determine a person's interest or right in property compulsorily acquired, whether such acquisition was for a public purpose, the amount of compensation to which a person is entitled and for enforcement of a person's right to any such compensation; (ii) are in breach of the principle of equality before the law and the rule of law; and (iii) on their own do not fulfill the intention of the legislature of the Belize Government and are inextricably bound up with the legislation ruled to be unconstitutional in the Telemedia Judgment.

The consolidated appeal hearing occurred from October 8 to October 10, 2012. However, since one of the judges on the panel was the subject of a complaint to the Belize Judicial Council by parties to the Telemedia Judgment, an application for disqualification of that judge was made and subsequently denied by a majority of the appeal panel. In December 2012 the Caribbean Court of Justice ("CCJ") entertained an application for special leave to appeal the above-noted majority decision denying the disqualification of the judge in question. During argument of the application, the CCJ accepted that the decision not to disqualify the judge could become grounds for appeal of the judgment of the Belize Court of Appeal and, as a result, the special leave to appeal was withdrawn by the applicants.

Counsel for the GOB admitted during the October 2012 consolidated appeal hearing that the *Acquisition Act* and *Acquisition Order* were contrary to the laws of Belize as they now stand, on the basis of the Belize Court of Appeal decision regarding the 2009 expropriation of Belize Telemedia, but that the severed provisions of the *Eighth Amendment* preclude return of majority control over Belize Electricity back to Fortis. The decision of the Belize Court of Appeal is pending. Any decision of the Belize Court of Appeal may be appealed to the CCJ, the highest court of appeal available for judicial matters in Belize.

Consequent to the deprivation of control over the operations of Belize Electricity, the Corporation discontinued the consolidation method of accounting for the utility, as of June 20, 2011. The Corporation has classified the book value of the expropriated investment in Belize Electricity as a long-term other asset on the consolidated balance sheet. As at December 31, 2012, the long-term other asset, including foreign exchange impacts, totalled $104 million (December 31, 2011 – $106 million). Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by the independent valuators. The GOB also commissioned a valuation of Belize Electricity which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset. While Fortis and representatives and third-party consultants of the GOB have held discussions in 2012 on differences in assumptions used in the valuations, there have been no discussions on any compensation settlement amount.

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

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generating subsidiary in Belize. As at February 28, 2013, Belize Electricity owed BECOL US$5 million for overdue energy purchases representing over 20% of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Management Discussion and Analysis

Weather and Seasonality Risk: The physical assets of the Corporation and its subsidiaries could be exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At FEI a BCUC-approved RSA serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing FEI to accumulate the margin impact of variations in the actual-versus-forecasted gas volumes consumed by residential and commercial customers. Also, at FortisBC Electric, electricity revenue variances from forecast for rate-setting purposes are permitted regulatory deferral account treatment as approved by the BCUC. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

At the FortisBC Energy companies, weather has a significant impact on distribution volume as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the FortisBC Energy companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Earnings of the FortisBC Energy companies are highest in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and unusual or severe temperatures. In Canada cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load. In the Caribbean the impact of seasonal changes in weather on air conditioning demand is less pronounced, due to the less variable seasonal changes that exist in the region; however, higher- or lower-than-normal temperatures can have a significant impact on air conditioning demand. Significant fluctuations in weather-related demand for electricity could have a material adverse effect on the financial condition and results of operations of the electric utilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric.

FortisBC Electric's entitlement to capacity and energy under the Canal Plant Agreement may be reduced if climate change in the future leads to a significant and sustained loss of precipitation over the entire headwaters of the Kootenay River system. To have an effect on the entitlements of capacity and energy, such change would likely have to persist for a prolonged period.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to utilities. Climate change, however, may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Newfoundland Power and Maritime Electric are subject to hurricane risk while the assets and earnings of FortisAlberta are subject to tornado risk. The Corporation's other utilities may also be subject to severe weather events. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. The Fortis Turks and Caicos utilities do not have a specific hurricane cost recovery mechanism; however, the utilities may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets are sensitive to rainfall levels; however, the geographic diversity of the Corporation's generation assets helps to reduce risk associated with rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation.

Commodity Price Risk: The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. The operation of BCUC-approved RSAs to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility. The FortisBC Energy companies employ various strategies to reduce exposure to commodity rates charged to customers due to natural gas price volatility. As ordered by the BCUC, the FortisBC Energy companies discontinued most hedging activities by mid-2011, with existing hedges being managed to expiry. The absence of such hedging tools may result in an increased exposure by customers to market price volatility on a go-forward basis.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk, mainly associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. Also, a severe and prolonged increase in natural gas commodity costs could materially affect the FortisBC Energy companies despite regulatory measures available to compensate for changes in these costs. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Derivative Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates, and fuel and natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. Mark-to-market is the default accounting treatment for all derivative instruments unless they qualify, and are designated, for one of the elective accounting treatments. Mark-to-market requires the derivative instrument to be recorded at fair value with changes in fair value recognized in earnings. As at December 31, 2012, the Corporation's derivative instruments consisted of fuel option contracts, natural gas swap and option contracts and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities and the remaining derivative instruments are held by the FortisBC Energy companies. At the FortisBC Energy companies and Caribbean Utilities, any difference between the amount recognized upon a change in the fair value of a derivative instrument and the amount recovered from customers in current rates is subject to regulatory deferral account treatment to be recovered from, or refunded to, customers in future rates.

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

As at December 31, 2012, all of the Corporation's corporately issued US$557 million (December 31, 2011 – US$550 million) long-term debt is designated as a hedge of the Corporation's foreign net investments. As at December 31, 2012, the Corporation had approximately US$17 million (December 31, 2011 – US$6 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 borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective from June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity, recorded in long-term other assets, does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. In 2012 the Corporation recognized in earnings foreign exchange losses of approximately $2 million. In 2011 the Corporation recognized in earnings a net foreign exchange gain of approximately $1 million ($1.5 million after tax).

It is estimated that a 5 cent, or 5%, increase or decrease in the US dollar-to-Canadian dollar exchange rate from the exchange rate of US$1.00=CDN$0.9949, as at December 31, 2012, would increase or decrease basic earnings per common share of Fortis by 2 to 3 cents in 2013, before considering the impact of the pending CH Energy Group acquisition.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar earnings streams, where possible, through future US dollar borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative instruments, including existing natural gas commodity swaps and options. The FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit approval practices. The FortisBC Energy companies did not experience any counterparty defaults in 2012 and do not expect any counterparties to fail to meet their obligations. As events in the past several years have indicated, however, the credit quality of counterparties can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Substantially all of FortisAlberta's distribution service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. Refer also to the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since the majority of electricity prices in British Columbia were set based on the historical average cost of production, primarily associated with hydroelectric generation rather than based on market forces, the competitive advantage of natural gas was substantially eroded during the decade that followed. More recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis. Going forward, a decrease in growth of natural gas production due to low market prices, increased demand due to industrial growth, coal-plant retirements and the potential for LNG exports are factors that may lead to materially higher market gas prices and increased volatility. These have the potential to impact natural gas competitiveness over the longer term.

Government policy has also impacted the competitiveness and perception of the benefits of natural gas in British Columbia. In 2008 the Government of British Columbia introduced changes to energy policy, including GHG emission reduction targets and a consumption tax on carbon-based fuels. It did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon-based energy sources or other energy sources.

There are other competitive challenges that are impacting the penetration of natural gas into new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, the FortisBC Energy companies have experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

In the future, if natural gas becomes less competitive due to pricing or other factors, the ability of the FortisBC Energy companies to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of the FortisBC Energy companies to fully recover COS in rates charged to customers.

Refer also to the "Business Risk Management – Risks Related to FEVI" and "Environmental Risks" sections of this MD&A.

Natural Gas, Fuel and Electricity Supply: The FortisBC Energy companies are dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas, where the majority of the natural gas distribution customers of the FortisBC Energy companies are located. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the FortisBC Energy companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the FortisBC Energy companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The addition of the LNG storage facility on Vancouver Island in 2011 helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may impact the ability of the FortisBC Energy companies to access cost-effective supply relative to other regional markets, due to increasing demand for gas supply from British Columbia. An increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia has taken place in recent years, which could result in price increases for customers over the long term. The potential development of large-scale LNG facilities to export gas to Asian markets could also significantly increase the demand for British Columbia natural gas and put upward pressure on prices.

The constrained regional infrastructure, high dependence on the Spectra Pipeline System and increased export demand for gas from British Columbia increases the risk that the FortisBC Energy companies will not be able to secure reliable, cost-effective supply for customers over the long term.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for over 80% of its customers' energy requirements. In addition, Caribbean Utilities and Fortis Turks and Caicos are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Power Supply and Capacity Purchase Contracts: FortisBC Electric's indirect customers are directly served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in an extreme case, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in rates charged to customers.

Additionally, the Corporation's regulated electric utilities periodically enter into various power supply and capacity purchase contracts with third and/or related parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts and, if the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity. The utilities are also exposed to power supply availability risk in the event of non-performance by counterparties to the various power supply and capacity contracts.

FortisBC Electric has a power supply sale agreement with BC Hydro for the sale of electricity generated from its non-regulated Walden hydroelectric generating facility. The agreement is set to expire in the fourth quarter of 2013. Accordingly, the Company is exposed to the risk that it will not be able to sell the power from this facility beyond the expiry of the current contract on similar terms.

In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion, the 335-MW hydroelectric generating facility currently under construction adjacent to the existing Waneta hydroelectric generating facility on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership between Fortis, which owns a 51% controlling interest, and CPC/CPT, which owns a 49% minority interest. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing was not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of FHI, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintains defined benefit pension plans for certain of their employees. Approximately 58% of the above utilities' total employees are members of such plans.

The defined benefit pension plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net pension cost. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with defined benefit pension plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Projected benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. The pension plan assets are valued at fair value. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets, which may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

Market-driven changes impacting discount rates, which are used to value the projected benefit obligations as at the measurement date, may result in material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements and the projected benefit obligation.

The above-noted risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power, actual net pension cost above or below forecasted net pension cost approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. There can be no assurance that the current regulator-approved deferral mechanisms will continue to exist in the future. An inability to flow through net pension costs in customer rates could have a material adverse effect on the results of operations and financial position of the regulated utilities. Also mitigating the above-noted risks is the fact that the defined benefit pension plans at FortisAlberta, Newfoundland Power and FortisOntario are closed to all new employees.

Risks Related to FEVI: FEVI operates in the price-competitive service area of Vancouver Island, with a customer base and revenue that are currently sufficient to meet the Company's current COS. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement provided royalty revenue from the Government of British Columbia that covered approximately 20% of FEVI's COS. The royalty revenue expired at the end of 2011, after which time FEVI's customers were required to absorb the full commodity cost of natural gas and all other COS. The Company also received approval from the BCUC in its 2012/2013 revenue requirements decision for the continuation of the Revenue Surplus Deferral Account mechanism, which continues to allow FEVI to recover costs from customers above FEVI's approved COS. Also, the remaining $29 million of outstanding non-interest-bearing government loans, which is currently treated as a government contribution against utility capital assets, is expected to be repaid by the end of 2016. As the debt is repaid, the higher rate base will increase COS and customer rates. With the cessation of royalty revenue and repayment of the government loans, the resultant increase in customer rates, as compared to electricity or alternative forms of energy, may make gas less competitive on Vancouver Island over time.

Environmental Risks: The Corporation's gas and electric utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity, mainly at the Corporation's regulated utilities in the Caribbean. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances.

The management of GHG emissions is the main environmental concern of the Corporation's Regulated Gas Utilities, primarily due to the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction* (*Cap and Trade*) *Act* and *Greenhouse Gas Reduction Targets Act*. The Energy Plan contains a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature passing the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act*, which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act*. The FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Reporting Program. While a cap-and-trade program associated with GHG emissions was expected to begin on January 1, 2012, the Government of British Columbia has delayed the development of this regulatory initiative. If implemented, the cap-and-trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amounts.

Management Discussion and Analysis

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details of the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

In 2011 Canada announced its decision to invoke its legal right to formally withdraw from the Kyoto Protocol. Canada is now negotiating a new international climate change treaty that could create binding GHG commitments for all major GHG emitters by 2015. It is uncertain as to what impact this process may have going forward.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs can arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages could become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2012, there were no material environmental liabilities recognized in the Corporation's 2012 Audited Consolidated Financial Statements. Also, there were no material unrecorded environmental liabilities known to management, except for the possibility of liabilities associated with various contingencies as discussed in the "Critical Accounting Estimates – Contingencies" section of this MD&A. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations and financial position of the Corporation and its subsidiaries.

Each of the utilities of Fortis has an Environmental Management System ("EMS"), with the exception of Fortis Turks and Caicos, which expects to complete the implementation of its EMS by the end of 2014. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders, including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

During 2012 direct costs arising from environmental protection, compliance, damages and the carrying out of the EMSs were not material to the Corporation's consolidated results of operations, cash flows or financial position. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their assets, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economically viable. The insurance coverage is for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover the loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, lost revenue and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Loss of Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government, government agencies and First Nations bands. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's subsidiaries.

FortisBC Electric's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the Canal Plant Agreement depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States, as well as the International Joint Commission's Order for Kootenay Lake. Government authorities in Canada and the United States have the power under the treaty and the International Joint Commission's Order to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence of, a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta) with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. This reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta. There are currently no transactions ongoing pursuant to the *Municipal Government Act* (Alberta) that relate to FortisAlberta.

Transition to New Accounting Standards: In June 2011 the Ontario Securities Commission ("OSC") issued a decision granting an exemption to Fortis and its reporting issuer subsidiaries to permit them to prepare their financial statements, effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission ("SEC") Issuers pursuant to Canadian securities laws. The Corporation and its reporting issuer subsidiaries, therefore, adopted US GAAP as opposed to International Financial Reporting Standards ("IFRS") on January 1, 2012. Earnings recognized under US GAAP are more closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities under US GAAP. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and caused significant volatility in the Corporation's consolidated earnings.

If the exemption from the OSC does not continue past December 31, 2014, the Corporation and its reporting issuer subsidiaries will then be required to become SEC Issuers in order to continue reporting under US GAAP. If the Corporation and its reporting issuer subsidiaries do not become or qualify as SEC Issuers, they will be required to adopt IFRS effective January 1, 2015. In the absence of an accounting standard for rate-regulated activities under IFRS at that time, the result could be volatility in earnings and earnings per common share from those otherwise recognized under US GAAP.

For further information on the Corporation's transition to US GAAP, effective January 1, 2012, refer to the "New Accounting Standards and Policies" section of this MD&A.

Changes in Tax Legislation: Fortis currently keeps the earnings of its Caribbean operations in offshore tax-free jurisdictions. Currently, dividends paid by foreign affiliates out of active business income earned in a jurisdiction with which Canada has not concluded a tax treaty are taxable in Canada when paid to its Canadian parent. However, legislative changes by the Government of Canada require that governments of these tax-free jurisdictions enter into tax treaties or other Tax Information Exchange Agreements ("TIEAs") with Canada. Once in force, the TIEAs will permit dividends paid out of active business income which was earned subsequent to the date of the TIEA coming into force to be exempted from tax when received in Canada. If the jurisdictions are unable to establish tax treaties or TIEAs within five years following the start of treaty or TIEA negotiations with Canada, earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis as if they were earned in Canada.

TIEAs are in place with the Cayman Islands, Bermuda and the Turks and Caicos Islands. Negotiations between the Government of Canada and the GOB commenced in June 2010. Fortis expects that a TIEA will be in place with Belize within the five-year deadline.

Income tax regulations in Canada were amended to provide that, where a particular TIEA enters into force on a particular day, the agreement is deemed to enter into force and come into effect on the first day of the year that includes the day when the TIEA came into effect. Therefore, earnings from the Corporation's investment in Caribbean Utilities and Fortis Turks and Caicos, beginning January 1, 2011, can be repatriated to Canada tax free. Conversely, if Belize is unable to establish a TIEA with Canada, earnings from BECOL will be taxed on an accrual basis as if they were earned in Canada which, for Fortis, will result in reduced earnings contribution from this subsidiary.

In August 2011 the Government of Canada introduced additional legislative proposals relating to the taxation of multinational corporations. These changes recommend new rules relating to upstream loans and propose a new regime for the repatriation of capital. The upstream loans, i.e., loans made from a foreign affiliate to its parent, will now be required to be repaid within two years, after which time any outstanding balances under the loans will be included in the taxable income of the Canadian parent. Fortis uses upstream interest-free loans from its Caribbean subsidiaries as a tax-deferred repatriation of earnings. As at December 31, 2012, the Corporation had approximately $67 million of upstream loans that will now have to be repaid before August 19, 2013, at which time any outstanding balances will be included in the Corporation's taxable income. As at December 31, 2012, the Corporation also had approximately $17 million of downstream loans that can be used to offset the impact of having to repay the upstream loans. In November 2012 transitional relief was provided to the upstream loan rules, proposing an extension of the date of required repayment of upstream loans outstanding from August 2013 to August 2016.

The new regime for the repatriation of capital will permit the Canadian parent to repatriate paid-up capital and exempt surplus before any taxable surplus, i.e., earnings before the coming into force of a TIEA, is repatriated. This will allow Fortis to receive a tax-free return of capital from the Caribbean, which can be used to repay upstream loans, enabling the Corporation to comply with the above legislative proposals.

Under the terms of the Corporation's first preference shares, the Corporation is subject to tax under Part VI.1 of the *Income Tax Act* (Canada) associated with dividends on its first preference shares. For corporations subject to Part VI.1 tax, there is an equivalent Part I tax deduction. As permitted under the *Income Tax Act* (Canada), a corporation may allocate its Part VI.1 tax liability and equivalent Part I tax deduction to its related subsidiaries. In the past, Fortis has allocated these items to Maritime Electric, Newfoundland Power and FortisOntario.

Upon transition to US GAAP, the Corporation reduced its consolidated opening 2012 retained earnings by $20 million to reflect the impact of differences between enacted and substantively enacted tax legislation, associated with prior assessments and payments of Part VI.1 taxes, and the recovery of Part I taxes. The adjustment was required as US GAAP requires tax provisions to be based on enacted versus substantively enacted legislation. A number of legislative amendments revising rates applicable to Part VI.1 taxes in Canada have yet to be enacted. The above-noted transitional US GAAP adjustment, as well as certain amounts recognized in 2012, will reverse through the Corporation's earnings in future periods when the legislation is finally enacted, which is expected in 2013, or as reassessment of corporate taxation years, upon which the enacted versus the substantively enacted rates were used to calculate taxes payable under US GAAP for financial reporting purposes, become statute-barred. During 2012 Newfoundland Power recorded a favourable $2.5 million adjustment to income taxes associated with statute-barred Part VI.1 taxes (2011 – $1 million).

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings. See also the "Business Risk Management – Regulatory Risk" section of this MD&A.

Information Technology Infrastructure Risk: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities, including the communication infrastructure and supporting systems which are necessary to provide important safety information to mobile devices for field staff; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business. While the utilities have various measures in place to help protect their information systems against cyber attacks, there is no assurance that such attacks may not occur. System failures could have a material adverse effect on the utilities, such as the inability to provide energy to customers.

Access to First Nations' Lands: The FortisBC Energy companies and FortisBC Electric provide service to customers on First Nations' lands and maintain gas distribution facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of the FortisBC Energy companies and FortisBC Electric is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the FortisBC Energy companies and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on the FortisBC Energy companies' and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult First Nations and to accommodate, if necessary, and, if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of FortisBC's gas and electricity businesses.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material adverse effect on FortisAlberta.

Labour Relations Risk: Approximately 58% of the employees of the Corporation's subsidiaries are members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material adverse effect on the results of operations, cash flows and financial position of the utilities.

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

A collective agreement between customer service employees at the FortisBC Energy companies and FortisBC Electric, and COPE, Local 378, expires on March 31, 2014.

The collective agreement between the FortisBC Energy companies and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on March 31, 2011. IBEW, Local 213, represents employees in specified occupations in the areas of T&D. A new four-year collective agreement, expiring on March 31, 2015, was reached in mid-2012.

The collective agreement between employees in specified occupations in the areas of administration and operations support at FortisBC Electric and COPE, Local 378, expires on December 31, 2013.

The collective agreement between FortisBC Electric and IBEW, Local 213, expired on January 31, 2013. IBEW, Local 213, represents employees in specified occupations in the areas of generation and T&D.

The collective agreement between FortisAlberta and the United Utility Workers' Association of Canada, Local 200, expires on December 31, 2013.

The two collective agreements between Newfoundland Power and IBEW, Local 1620, expired on September 30, 2011. One of the two newly negotiated collective agreements was ratified during the first quarter of 2012; the other was ratified in May 2012. The agreements are for three-year terms expiring on September 30, 2014.

Human Resources Risk: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and in the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

NEW ACCOUNTING STANDARDS AND POLICIES

Transition to US GAAP: In June 2011 the OSC issued a decision allowing Fortis and its reporting issuer subsidiaries to prepare their financial statements, effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. SEC Issuers. The Corporation and its reporting issuer subsidiaries, therefore, adopted US GAAP as opposed to IFRS on January 1, 2012 with the restatement of comparative reporting periods. Earnings recognized under US GAAP are more closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities under US GAAP. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and caused significant volatility in the Corporation's consolidated earnings. On March 16, 2012, Fortis voluntarily prepared and filed audited consolidated US GAAP financial statements for the year ended December 31, 2011 with 2010 comparatives on SEDAR. Also included in the voluntary filing were: (i) a detailed reconciliation between the Corporation's audited consolidated Canadian GAAP and audited consolidated US GAAP financial statements for fiscal 2011, including 2010 comparatives; and (ii) a detailed reconciliation between the Corporation's 2011 interim unaudited consolidated Canadian GAAP and 2011 interim unaudited consolidated US GAAP financial statements.

New Accounting Policies: Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-ARO removal costs in depreciation, as requested in their 2012/2013 RRA and subsequently approved by the regulator in its April 2012 decision. The accrual of estimated non-ARO removal costs is included in depreciation and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Non-ARO removal costs are direct costs incurred by the FortisBC Energy companies in taking assets out of service, whether through actual removal of the assets or through disconnection of the assets from the transmission or distribution system. Prior to 2012 estimated non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses with variances between actual non-ARO removal costs and those forecasted for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. During 2012 non-ARO removal costs of $20 million were accrued by the FortisBC Energy companies as part of depreciation and actual non-ARO removal costs of $16 million, net of salvage proceeds, were incurred and recognized against the long-term regulatory liability. During 2011 actual non-ARO removal costs of approximately $17 million, net of salvage proceeds, were incurred by the FortisBC Energy companies, with $12 million recognized in operating expenses and $5 million deferred as a regulatory asset.

Prior to 2012 variances from forecast, adjusted for certain revenue and cost variances which flowed through to customers, for rate-setting purposes were shared equally between customers and FortisBC Electric. As applied for in FortisBC Electric's 2012/2013 RRA and approved by the BCUC, prospectively from January 1, 2012, the above-noted sharing of positive or negative variances is no longer in effect. Beginning in 2012 variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates are subject to full deferral account treatment to be recovered from, or refunded to, customers in future rates and, therefore, did not impact earnings in 2012. Effective January 1, 2012, however, the flow-through treatment for finance charges, as was applied for in FortisBC Electric's 2012/2013 RRA, was denied by the regulator pursuant to its revenue requirements decision. As a result, a retroactive adjustment was recorded in the third quarter of 2012 to eliminate the flow-through treatment. Variances between actual finance charges from those forecasted in determining customer electricity rates, therefore, had an impact on earnings in 2012.

Effective January 1, 2012, as approved by the regulator, the FortisBC Energy companies are deferring variances between actual depreciation and that forecasted in determining customer gas rates.

For 2012, as approved by the regulator, FortisAlberta was not permitted to defer transmission volume variances associated with its AESO charges deferral account. During 2012 FortisAlberta recognized approximately $8.5 million of net transmission revenue as a result of this change.

Effective January 1, 2012, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 350, *Intangibles – Goodwill and Other* ("ASC Topic 350") related to the testing for impairment of goodwill and early adopted the amendments related to the testing for impairment of indefinite-lived intangible assets. The amended standard allows entities testing goodwill and indefinite-lived intangible assets for impairment to have the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required. Previous guidance in ASC Topic 350 required an entity to test goodwill and indefinite-lived intangible assets for impairment, at least on an annual basis, by calculating fair value and comparing it to carrying value. If the carrying amount exceeds fair value, an impairment charge is required. In 2012 Fortis chose to perform internal quantitative and qualitative assessments for certain reporting units to which goodwill was allocated and for certain indefinite-lived intangible assets and concluded that fair value was 50% or more likely to be greater than carrying value in all instances. For a further discussion of the assessment of impairment for goodwill and indefinite-lived intangible assets, refer to the "Critical Accounting Estimates – Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets" section of this MD&A.

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures*. The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP and IFRS. The amendments did not change what items are measured at fair value but instead made various changes to the guidance pertaining to how fair value is measured. The changes did not have a material impact on the Corporation's 2012 Audited Consolidated Financial Statements.

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 220, *Comprehensive Income*. The amended standard requires entities to report components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate but consecutive statements. The option to report other comprehensive income and its components in the statement of shareholders' equity has been eliminated. Although the new guidance changes the presentation of comprehensive income, there are no changes to the components that are recognized in net income or other comprehensive income under existing guidance. The amended standard did not change the Corporation's financial statement presentation of comprehensive income, which is reported in a separate but consecutive statement.

FUTURE ACCOUNTING PRONOUNCEMENTS

Disclosures About Offsetting Assets and Liabilities: Effective January 1, 2013, the Corporation is adopting the amendments to ASC Topic 210, *Balance Sheet – Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update No. 2011-11. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The amended disclosures are intended to assist financial statement users in understanding significant quantitative differences between balance sheets prepared under US GAAP and IFRS. Fortis does not expect that the adoption of the above amendments will have a material impact on its consolidated financial statements.

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

As at December 31	**2012**		2011	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**47**	**51**	45	49
Long-term debt, including current portion	**5,900**	**7,338**	5,788	7,197

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, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) by obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The Financial Instruments table above excludes the long-term other asset associated with the Corporation's expropriated investment in Belize Electricity. Due to uncertainty in the ultimate amount and ability of the GOB to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the book value of the expropriated investment, including foreign exchange impacts, in long-term other assets, which totalled approximately $104 million as at December 31, 2012 (December 31, 2011 – $106 million).

The following table summarizes the Corporation's derivative instruments.

Derivative Instruments

As at December 31	2012				2011
Liability	**Maturity**	**Number of Contracts**	**Volume** [1]	**Carrying Value** [2] ***($ millions)***	Carrying Value [2] *($ millions)*
Fuel option contracts	**2013**	**6**	**14**	**(1)**	(1)
Natural gas derivatives:					
Gas swaps and options	**2014**	**59**	**27**	**(51)**	(135)
Gas purchase contract premiums	**2014**	**46**	**82**	**(8)**	–

[1] The volume for fuel option contracts is reported in millions of imperial gallons and for natural gas derivatives is reported in PJ.
[2] Carrying value is estimated fair value. The liability represents the gross derivatives balance.

The fuel option contracts are held by Caribbean Utilities and are used to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fuel option contracts mature on or before October 1, 2013. Approximately 70% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to mitigate gas price volatility on customer rates and to reduce the risk of regional price discrepancies. As directed by the regulator in 2011, the FortisBC Energy companies have suspended their commodity hedging activities, with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. For further information refer to the "Business Risk Management – Commodity Price Risk" section of this MD&A.

The changes in the fair values of the fuel option contracts and natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. The fair values of the derivative financial instruments were recognized in accounts payable and other current liabilities as at December 31, 2012 and 2011.

The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and was calculated using published market prices for heating oil or similar commodities. 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 commodity cost of natural gas. The fair values of the fuel option contracts and the natural gas derivatives were estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate 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.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's 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. Certain amounts are recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates 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. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known.

During the second quarter of 2012, the FortisBC Energy companies and FortisAlberta received revenue requirements decisions, effective January 1, 2012, the cumulative impacts of which, where such impacts were different from those estimated, were recorded in the second quarter of 2012. Also during the second quarter of 2012, Newfoundland Power received a decision on its 2012 Cost of Capital Application approving an increase in the allowed ROE, effective January 1, 2012, the cumulative impacts of which were recorded in the second quarter of 2012. Similarly, FortisBC Electric recorded the cumulative impacts of its revenue requirements decision, effective January 1, 2012, in the third quarter of 2012 when the decision was received.

As at December 31, 2012, Fortis recognized $1,700 million in current and long-term regulatory assets (December 31, 2011 – $1,618 million) and $753 million in current and long-term regulatory liabilities (December 31, 2011 – $663 million).

Depreciation and Amortization: Depreciation and amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2012, the Corporation's consolidated utility capital assets, income producing properties and intangible assets were approximately $10.6 billion, or approximately 71% of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangible assets of approximately $9.9 billion, or approximately 70% of total consolidated assets, as at December 31, 2011. The increase in capital assets was primarily associated with capital expenditures, which totalled approximately $1.1 billion in 2012. Depreciation and amortization was $470 million for 2012 compared to $416 million for 2011. Changes in depreciation rates may have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation and amortization rates are approved by the respective regulatory authority. As required by their respective regulator, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-ARO removal costs in depreciation with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred.

As required by the regulator, effective January 1, 2012, depreciation rates at the FortisBC Energy companies now include an amount allowed for regulatory purposes to accrue for estimated non-ARO removal costs, net of salvage proceeds. The impact of the inclusion, effective January 1, 2012, in depreciation rates of the accrual of estimated non-ARO removal costs has been reflected in the FortisBC Energy companies' approved revenue requirements and resulting customer rates.

The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2012 was $486 million (December 31, 2011 – $455 million). The total amount of non-ARO removal costs accrued and recognized in depreciation expense during 2012 was $67 million (2011 – $52 million).

The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates as approved by the regulator. The most recently completed depreciation study performed at Newfoundland Power was filed with the regulator as part of the Company's 2013/2014 General Rate Application. The depreciation study, which was based on capital assets in service as at December 31, 2010, indicated an accumulated depreciation variance of approximately $3 million. Subject to regulatory approval, this variance is expected to increase the depreciation of utility capital assets in future years, which will be recovered in future customer rates.

Changes in regulator-approved depreciation rates at FortisAlberta and FortisBC Electric, in conjunction with approved depreciation studies and revenue requirements decisions received in 2012, have impacted consolidated depreciation expense. The composite depreciation rate for utility capital assets at FortisAlberta decreased to 3.9% for 2012 from 4.1% for 2011. FortisBC Electric's composite depreciation rate for utility capital assets decreased to 2.9% for 2012 from 3.2% for 2011.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance might vary from actual amounts incurred.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1.

As at December 31, 2012, consolidated goodwill totalled approximately $1.6 billion (December 31, 2011 – $1.6 billion). Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at FEI, FEVI and FortisBC Electric and totalled approximately $66 million on a consolidated basis as at December 31, 2012 (December 31, 2011 – $64 million).

Impairment testing for indefinite-lived intangible assets at the regulated utilities is carried out at the reporting unit level. A fair rate of return on the indefinite-lived intangible assets is provided through customer gas and electricity rates as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Prior to adopting amendments to ASC Topic 350, fair value of each of the Corporation's reporting units was estimated on an annual basis by an independent external consultant. Upon adopting the above-noted amendments, Fortis performs an annual internal quantitative assessment for each reporting unit and, for those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an independent external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an independent external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each reporting unit estimated by an independent external consultant once every three years.

Effective January 1, 2012, Fortis has adopted the above-noted approach for the annual testing for goodwill impairment for its annual testing of impairment for indefinite-lived intangible assets.

As at October 1, 2012, an internal assessment of quantitative and qualitative factors was performed for goodwill allocated to reporting units FortisAlberta, FortisBC Electric, Maritime Electric and Cornwall Electric. It was determined that fair value of the reporting units was 50% or more likely to be greater than carrying value and, therefore, goodwill, and the indefinite-lived intangible assets at FortisBC Electric, were not impaired.

As at October 1, 2012, the fair value of reporting units FEI, FEVI, Caribbean Utilities, Fortis Turks and Caicos and FortisOntario (combined Canadian Niagara Power and Algoma Power), to which goodwill was allocated, was estimated by an independent external consultant and determined to be in excess of carrying value. Therefore, goodwill, and the indefinite-lived intangible assets at FEI and FEVI, were not impaired.

In calculating goodwill impairment, Fortis determines those reporting units which will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was more likely than not to be below its carrying value.

The primary method for estimating fair market value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

No impairment provisions were required in either 2012 or 2011 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension and OPEB plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2013 is 6.41%, which is down from 6.72% used in 2012. The defined benefit pension plan assets experienced total positive returns of approximately $67 million in 2012 compared to expected positive returns of $50 million. The assumed expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2012 and determine net pension cost for 2013 is 4.14%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2011 and determine net pension cost for 2012 of 4.62%. The decrease in the assumed weighted average discount rate is mainly due to lower credit risk spreads and cost of capital on investment-grade corporate bonds. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

There was a $6 million increase in consolidated defined benefit net pension cost for 2012 compared to 2011, mainly as a result of the impact of lower assumed discount rates for calculating net pension cost in 2012 compared to 2011 and the amortization of net actuarial losses that arose in prior years, partially offset by higher expected returns on plan assets and higher regulatory adjustments.

Consolidated defined benefit net pension cost for 2013 is expected to be comparable to 2012. Increased costs resulting from lower discount rates assumed and the amortization of actuarial losses are expected to be largely offset by an increase in estimated returns on plan assets, due to a higher asset base, and increased regulatory adjustments. Any increases in defined benefit net pension cost at the regulated utilities are expected to be recovered from customers in rates, subject to forecast risk at those utilities with smaller defined benefit plans.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2012 net defined benefit pension cost, and the related consolidated projected benefit obligation recognized in the Corporation's 2012 Annual Consolidated Financial Statements. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2012

Increase (decrease)	**Net pension benefit cost**		**Projected benefit obligation** [(1)]	
($ millions)	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**
Impact of increasing the rate of return assumption by 100 basis points	4	(4)	49	3
Impact of decreasing the rate of return assumption by 100 basis points	(3)	3	(42)	(11)
Impact of increasing the discount rate assumption by 100 basis points	(10)	(12)	(73)	(87)
Impact of decreasing the discount rate assumption by 100 basis points	11	12	89	109

[(1)] At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the projected benefit obligation, is based on the expected long-term rate of return on pension plan assets. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return on plan asset assumption at the FortisBC Energy companies and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring defined benefit net pension cost and/or the projected benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, along with the health care cost trend rate, were also utilized by management in determining OPEB plan cost and accumulated benefit obligation.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2012 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2012 Annual Consolidated Financial Statements. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Increase (decrease)	**Net OPEB cost**		**Accumulated benefit obligation**	
($ millions)	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**
Impact of increasing the health care cost trend rate assumption by 100 basis points	1	1	12	21
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(1)	(1)	(9)	(18)
Impact of increasing the discount rate assumption by 100 basis points	–	(2)	(14)	(23)
Impact of decreasing the discount rate assumption by 100 basis points	–	2	22	27

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. As discussed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the FortisBC Energy companies, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecasted net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above deferral mechanisms at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2012, for all defined benefit and OPEB plans, the Corporation had consolidated benefit obligations of $1,417 million (December 31, 2011 – $1,263 million) and consolidated plan assets of $868 million (December 31, 2011 – $785 million), for a consolidated funded status in a liability position of $549 million (December 31, 2011 – $478 million). During 2012 the Corporation recognized consolidated net benefit cost of $62 million (2011 – $55 million) for all defined benefit and OPEB plans.

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2012 and 2011, with the exception of AROs recognized by FortisBC Electric.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2012, FortisBC Electric has recognized an approximate $3 million ARO (December 31, 2011 – $4 million) associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment, which has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating FortisBC Electric's ARO represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. The ARO may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2012, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

Revenue Recognition: Revenue at the Corporation's regulated utilities is recognized on an accrual basis. Gas and electricity consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically, usually monthly, and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2012, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $284 million (December 31, 2011 – $341 million) on annual consolidated revenue of $3,654 million for 2012 (2011 – $3,738 million). The decrease in accrued revenue of $57 million from December 31, 2011 was driven primarily by FortisAlberta and the FortisBC Energy companies. The decrease at FortisAlberta was mainly attributable to a change in the billing cycle for distribution tariff billings from monthly to weekly billings. The decrease at the FortisBC Energy companies reflected lower commodity costs of natural gas charged to customers.

Capitalized Overhead: As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

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 contingent liabilities.

Fortis

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

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI is appealing the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions. FHI was advised that all matters have now been settled and the action has been dismissed by consent.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 in relation to the same matter, which claims have now been settled. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

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

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2012, 2011 and 2010. The financial information has been prepared in Canadian dollars and in accordance with US GAAP.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2012**	2011	2010
Revenue	**3,654**	3,738	3,647
Net earnings	**371**	366	375
Net earnings attributable to common equity shareholders	**315**	311	320
Total assets	**14,950**	14,214	13,411
Long-term debt (excluding current portion)	**5,783**	5,685	5,616
Preference shares	**1,108**	912	912
Common shareholders' equity	**3,992**	3,823	3,253
Basic earnings per common share	**1.66**	1.71	1.85
Diluted earnings per common share	**1.65**	1.70	1.81
Dividends declared per common share (1)	**1.21**	1.17	1.41
Dividends declared per First Preference Share, Series C (1)	**1.3625**	1.3625	1.7031
Dividends declared per First Preference Share, Series E (1)	**1.2250**	1.2250	1.5313
Dividends declared per First Preference Share, Series F (1)	**1.2250**	1.2250	1.5313
Dividends declared per First Preference Share, Series G (1)	**1.3125**	1.3125	1.6406
Dividends declared per First Preference Share, Series H (1) (2)	**1.0625**	1.0625	1.1636
Dividends declared per First Preference Share, Series J (3)	**0.3514**	–	–

(1) First quarter 2010 dividends were declared in January 2010, resulting in three quarters of dividends declared in 2009 and five quarters of dividends declared in 2010

(2) A total of 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H were issued in January 2010 at $25.00 per share for net after-tax proceeds of $245 million, which are entitled to receive cumulative dividends in the amount of $1.0625 per share per annum for the first five years.

(3) A total of 8 million First Preference Shares, Series J were issued in November 2012 at $25.00 per share for net after-tax proceeds of $196 million, which are entitled to receive cumulative dividends in the amount of $1.1875 per share per annum.

2012/2011: Revenue decreased $84 million, or 2.2%, from 2011 and net earnings attributable to common equity shareholders grew to $315 million, up $4 million from 2011. For a discussion of the reasons for the changes in revenue and net earnings attributable to common equity shareholders year over year, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflected the Corporation's continued investment in regulated energy systems, driven by capital spending at the regulated utilities in western Canada, and the continued construction of the non-regulated Waneta Expansion in British Columbia. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2012 of committed corporate credit facility borrowings, classified as long term, with a portion of the proceeds from the Corporation's $200 million public preference share offering.

Basic earnings per common share were $1.66 in 2012 compared to $1.71 in 2011. The decrease was due to the impact of a 5% increase in the weighted average number of common shares outstanding, largely associated with the public common equity offering in mid-2011, partially offset by higher net earnings attributable to common equity shareholders.

2011/2010: Revenue increased $91 million, or 2.5%, over 2010. The increase was mainly due to: (i) an increase in gas delivery rates and the base component of electricity rates at most of the Corporation's Canadian Regulated Utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure, forecasted certain higher regulator-approved expenses recoverable from customers and a higher allowed ROE at Algoma Power; (ii) the flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities; (iii) growth in the number of customers, mainly at FortisAlberta; (iv) higher natural gas sales; and (v) higher electricity sales at Canadian Regulated Electric Utilities. The above-noted items were partially offset by the impacts of: (i) the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011; (ii) lower commodity cost of natural gas charged to customers; and (iii) approximately $15 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year.

Net earnings attributable to common equity shareholders were $311 million compared to $320 million for 2010. Excluding: (i) the one-time $46 million favourable impact to Newfoundland Power's earnings in 2010 due to the recognition of a regulatory asset, as required under US GAAP, to recognize amounts recoverable from customers upon regulatory approval of the adoption of the accrual method of accounting for OPEB costs; and (ii) the $11 million after-tax fee paid to Fortis in July 2011 following the termination of a Merger Agreement with CVPS, earnings increased $26 million over 2010. The increase in earnings was mainly the result of higher earnings from the Corporation's Canadian Regulated Utilities associated with: (i) rate base growth, driven by the regulated utilities in western Canada; (ii) lower-than-expected corporate income taxes, finance charges and depreciation, and increased gas transportation volumes to industrial customers at the FortisBC Energy companies, partially offset by lower-than-expected customer additions at these companies; (iii) higher capitalized AFUDC at FortisAlberta, as well as customer growth and increased energy deliveries, return earned on additional investment in automated meters, as approved by the regulator, and an approximate $1 million gain on the sale of property, partially offset by the impact of a lower allowed ROE for 2011 at the utility; (iv) lower purchased power costs and higher electricity sales at FortisBC Electric, partially offset by lower capitalized AFUDC at the utility; (v) an increase in the allowed ROE at Algoma Power; and (vi) lower corporate business development costs and finance charges. The above increases were partially offset by: (i) lower earnings from Caribbean Regulated Electric Utilities, due to the expropriation of Belize Electricity in June 2011, combined with lower earnings at Fortis Turks and Caicos due to higher operating expenses and depreciation, partially offset by reduced energy supply costs in 2011; (ii) decreased earnings at Fortis Properties reflecting higher income taxes and lower occupancies at hotels in western Canada; and (iii) decreased earnings from non-regulated hydroelectric generation operations, largely due to lower production in Belize as a result of reduced rainfall, and overall lower interest income.

The growth in total assets was primarily due to the Corporation's continued investment in regulated energy systems, driven by capital spending in western Canada, the continued construction of the non-regulated Waneta Expansion and the favourable impact of foreign exchange associated with the translation of foreign currency-denominated assets. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2011 of committed corporate credit facility borrowings, classified as long term, with a portion of the proceeds from the $341 million public common equity offering. The increases in total assets and long-term debt were partially offset by the impact of the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility in 2011.

Basic earnings per common share were 14 cents, or 7.6% lower than in 2010. Excluding the one-time items affecting each of 2011 and 2010 as described above, basic earnings per common share were higher year over year, mainly due to otherwise increased earnings, partially offset by the impact of an increase in the weighted average number of common shares outstanding, mainly associated with the public common equity offering in mid-2011.

Dividends declared per common and preference shares for 2011 decreased from 2010 as a result of the timing of the declaration of dividends, partially offset by a 3.4% increase in the quarterly common share dividend declared in the fourth quarter of 2011. First quarter 2010 dividends were declared in January 2010, when normally they would have been declared in the fourth quarter of the preceding year, resulting in five quarters of dividends per common share being declared in 2010.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2012 and 2011. The financial information has been prepared in Canadian dollars and in accordance with US GAAP. A discussion of the financial results for the fourth quarter of 2012 is also contained in the Corporation's fourth quarter 2012 media release, dated and filed on SEDAR at www.sedar.com on February 7, 2013, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31 *(Unaudited)*	**Gas Volumes Energy and Electricity Sales**			**Revenue** *($ millions)*		
	2012	2011	Variance	**2012**	2011	Variance
Regulated Gas Utilities – Canadian *(PJ)*						
FortisBC Energy Companies	**60**	63	(3)	**422**	476	(54)
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,365**	4,232	133	**113**	102	11
FortisBC Electric	**830**	843	(13)	**81**	81	–
Newfoundland Power	**1,539**	1,527	12	**159**	156	3
Other Canadian Electric Utilities	**578**	568	10	**89**	83	6
	7,312	7,170	142	**442**	422	20
Regulated Electric Utilities – Caribbean	**181**	174	7	**71**	71	–
Non-Regulated – Fortis Generation	**50**	112	(62)	**5**	9	(4)
Non-Regulated – Fortis Properties				**61**	58	3
Corporate and Other				**6**	6	–
Inter-Segment Eliminations				**(8)**	(8)	–
Total				**999**	1,034	(35)

Factors Contributing to Gas Volumes Variance

Unfavourable

- Lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures

Favourable

- Higher gas transportation volumes to industrial customers, due to certain customers switching to natural gas from alternative sources of fuel as a result of low natural gas prices

Factors Contributing to Energy and Electricity Sales Variances

Favourable

- Increased energy deliveries at FortisAlberta, associated with higher average consumption by oil field and commercial customers, due to increased activity; higher average consumption by residential customers, driven by cooler temperatures in the fourth quarter of 2012, which increased heating load; and growth in the number of customers, mainly in the residential and commercial sectors, driven by favourable economic conditions
- Increased electricity sales at Newfoundland Power, associated with growth in the number of customers and a higher concentration of electric-versus-oil heating in new home construction combined with economic growth, which increased consumption. The increase was partially offset by sunnier weather conditions, which reduced average consumption.
- Increased electricity sales at Other Canadian Regulated Electric Utilities, due to growth in the number of residential and commercial customers on PEI; higher average consumption by residential customers on PEI, due to colder temperatures, and an increase in the number of such customers using electricity for home heating; and higher average consumption by commercial customers in the agricultural processing sector on PEI
- Increased electricity sales at Caribbean Regulated Electric Utilities, due to electricity sales of 6 GWh at TCU, which was acquired in August 2012; higher tourism activity in the Turks and Caicos Islands; and growth in the number of customers, excluding the impact of customers acquired with TCU

Unfavourable

- Lower energy sales at Non-Regulated – Fortis Generation related to decreased production in Belize and Upstate New York, due to lower rainfall
- Lower electricity sales at FortisBC Electric as a result of lower average consumption, due to warmer weather

Factors Contributing to Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures
- Decreased non-regulated hydroelectric production, mainly due to lower rainfall
- Decreased electricity sales at FortisBC Electric, as discussed above

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the regulated utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Net transmission revenue of approximately $2 million recognized at FortisAlberta, as a result of the 2012 distribution revenue requirements decision received in April 2012
- The flow through in customer electricity rates of higher energy supply costs, where applicable, at most of the regulated electric utilities, which increased revenue
- Increased electricity sales at Newfoundland Power, Maritime Electric and Fortis Turks and Caicos, as discussed above
- Growth in the number of customers, driven by FortisAlberta
- Higher pole-attachment revenue at FortisBC Electric and differences in the amount of PBR incentives refunded to FortisBC Electric's customers quarter over quarter
- Higher Hospitality revenue at Fortis Properties, due to revenue from the StationPark Hotel, which was acquired in October 2012

Segmented Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions, except per share amounts)	**2012**	2011	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**49**	51	(2)
Regulated Gas Utilities – Canadian			
FortisAlberta	**23**	16	7
FortisBC Electric	**12**	10	2
Newfoundland Power	**9**	8	1
Other Canadian Electric Utilities	**6**	2	4
	50	36	14
Regulated Electric Utilities – Caribbean	**3**	4	(1)
Non-Regulated – Fortis Generation	**2**	5	(3)
Non-Regulated – Fortis Properties	**5**	5	–
Corporate and Other	**(22)**	(19)	(3)
Net Earnings Attributable to Common Equity Shareholders	**87**	82	5
Basic Earnings per Common Share *($)*	**0.46**	0.44	0.02

Factors Contributing to Earnings Variance

Favourable

- Increased earnings at FortisAlberta, mainly due to rate base growth, net transmission revenue of $2 million recognized in the fourth quarter of 2012, and the rate revenue reduction accrual during the fourth quarter of 2011, reflecting the cumulative impact from January 1, 2011 of the decrease in the allowed ROE for 2011
- Increased earnings at Other Canadian Regulated Electric Utilities, mainly due to lower effective income taxes at Maritime Electric and the accrual of cumulative return earned on FortisOntario's capital investment in smart meters
- Increased earnings at FortisBC Electric, due to rate base growth, lower-than-expected finance charges in 2012, higher pole-attachment revenue and the expiry of the PBR mechanism on December 31, 2011

Unfavourable

- Decreased non-regulated hydroelectric production, mainly in Belize, due to lower rainfall, partially offset by an approximate $0.5 million after-tax gain recognized in the fourth quarter of 2012 on the involuntary disposition of generation assets in Upstate New York
- Increased corporate expenses, largely due to the $3 million non-recurring provision recognized in the fourth quarter of 2012 and lower effective income tax recoveries, partially offset by a foreign exchange gain of approximately $1 million recognized in the fourth quarter of 2012, compared to an after-tax net foreign exchange loss of approximately $1 million recognized in the fourth quarter of 2011, and lower finance charges
- Decreased earnings at the FortisBC Energy companies, due to the timing of certain operating and maintenance expenses during 2012, lower capitalized AFUDC and lower-than-expected customer additions in 2012, partially offset by rate base growth, higher gas transportation volumes to industrial customers and lower effective income taxes

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2012**	2011	Variance
Cash, Beginning of Period	**147**	106	41
Cash Provided by (Used in):			
Operating Activities	**172**	230	(58)
Investing Activities	**(319)**	(367)	48
Financing Activities	**154**	118	36
Cash, End of Period	**154**	87	67

Cash flow from operating activities was $58 million lower quarter over quarter. The decrease was mainly due to unfavourable changes in working capital at the FortisBC Energy companies and FortisAlberta. The unfavourable changes in working capital were associated with current regulatory deferral accounts and inventories. The above decrease was partially offset by favourable changes in long-term regulatory deferral accounts, higher earnings and the collection from customers of regulator-approved increased depreciation and amortization.

Cash used in investing activities was $48 million lower quarter over quarter. The decrease was mainly due to: (i) a $52 million deferred payment made in December 2011 in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002, which increased cash used in investing activities in 2011; (ii) a decrease in capital spending, mainly due to the timing of AESO transmission-related capital projects at FortisAlberta; and (iii) a decrease in cash used in business acquisitions. The decrease in cash used in business acquisitions was the result of the acquisition of the Hilton Suites Hotel in October 2011 for $25 million, compared to the acquisition of the StationPark Hotel in October 2012 for $7 million, net of debt assumed. The above decreases in cash used in investing activities were partially offset by lower proceeds from the sale of utility capital assets. In October 2011 Newfoundland Power sold joint-use poles and related infrastructure to Bell Aliant for $45 million, net of costs.

Cash provided by financing activities was $36 million higher quarter over quarter, due to: (i) proceeds from the issuance of preference shares in November 2012; (ii) higher net proceeds from short-term borrowings; and (iii) higher advances from non-controlling interests in the Waneta Partnership. The above increases were partially offset by: (i) lower proceeds from long-term debt; (ii) higher net repayments under committed credit facilities classified as long term; and (iii) higher repayments of long-term debt. In November 2012 Fortis completed a $200 million public offering of 8 million First Preference Shares, Series J. The net proceeds of approximately $194 million were used to repay borrowings under the Corporation's committed corporate credit facility, which borrowings were primarily incurred to support the construction of the Waneta Expansion and for other general corporate purposes.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2011 through December 31, 2012. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements, which have been prepared in accordance with US GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected using US GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	**Revenue** *($ millions)*	**Net Earnings Attributable to Common Equity Shareholders** *($ millions)*	**Earnings per Common Share** **Basic** *($)*	**Diluted** *($)*
December 31, 2012	999	87	0.46	0.45
September 30, 2012	714	45	0.24	0.24
June 30, 2012	792	62	0.33	0.33
March 31, 2012	1,149	121	0.64	0.62
December 31, 2011	1,034	82	0.44	0.43
September 30, 2011	699	56	0.30	0.30
June 30, 2011	846	57	0.32	0.32
March 31, 2011	1,159	116	0.66	0.64

Management Discussion and Analysis

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Earnings for the first, second and third quarters of 2012 were reduced by approximately $4 million, $3 million and $0.5 million, respectively, associated with costs incurred related to the pending acquisition of CH Energy Group. During the second quarter of 2012, the FortisBC Energy companies and FortisAlberta received revenue requirements decisions, effective January 1, 2012, the cumulative impacts of which, where such impacts were different from those estimated, were recorded in the second quarter of 2012. Similarly, FortisBC Electric recorded the cumulative impacts of its rate decision, effective January 1, 2012, in the third quarter of 2012 when the decision was received. Financial results for the fourth quarter ended December 31, 2012 reflected the acquisition of the StationPark Hotel in October 2012. Financial results from the fourth quarter ended December 31, 2011 reflected the acquisition of the Hilton Suites Hotel in October 2011. Earnings for the third quarter ended September 30, 2011 included the $11 million after-tax merger termination fee paid to Fortis by CVPS. Financial results from June 20, 2011 reflected the discontinuance of the consolidation method of accounting for Belize Electricity due to the expropriation of the utility by the GOB.

December 2012/December 2011: Net earnings attributable to common equity shareholders were $87 million, or $0.46 per common share, for the fourth quarter of 2012 compared to earnings of $82 million, or $0.44 per common share, for the fourth quarter of 2011. A discussion of the variances between the financial results for the fourth quarter of 2012 and the fourth quarter of 2011 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2012/September 2011: Net earnings attributable to common equity shareholders were $45 million, or $0.24 per common share, for the third quarter of 2012 compared to earnings of $56 million, or $0.30 per common share, for the third quarter of 2011. Earnings for the third quarter of 2012 were reduced by $3.5 million related to foreign exchange and CH Energy Group acquisition-related expenses. Earnings for the third quarter of 2011 were favourably impacted by a one-time $11 million after-tax merger termination fee paid to Fortis by CVPS and $2.5 million of foreign exchange. Excluding the above impacts, higher earnings at FortisAlberta and FortisBC Electric for the quarter were partially offset by decreased non-regulated hydroelectric generation in Belize, due to lower rainfall, and a higher loss incurred at the FortisBC Energy companies. The improved performance at FortisAlberta was due to net transmission revenue of $3.5 million recognized in the third quarter of 2012, rate base growth and the timing of operating expenses during 2012, partially offset by a lower allowed ROE. At FortisBC Electric, performance was driven by rate base growth, higher pole-attachment revenue and lower-than-expected finance charges. The higher loss at the FortisBC Energy companies related to the unfavourable impact of the difference in the timing of recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012, lower capitalized AFUDC and lower-than-expected customer additions in 2012. The above items were partially offset by higher gas transportation volumes to industrial customers and the timing of certain operating and maintenance expenses during 2012.

June 2012/June 2011: Net earnings attributable to common equity shareholders were $62 million, or $0.33 per common share, for the second quarter of 2012 compared to earnings of $57 million, or $0.32 per common share, for the second quarter of 2011. The increase in earnings was mainly due to higher contribution from FortisAlberta, increased non-regulated hydroelectric production in Belize associated with higher rainfall, and higher earnings at Newfoundland Power, partially offset by higher corporate expenses and decreased earnings at the FortisBC Energy companies. Higher contribution from FortisAlberta related to rate base growth, net transmission revenue of $3 million recognized in the second quarter of 2012 and reduced depreciation as approved by the regulator, partially offset by a lower allowed ROE. Higher earnings at Newfoundland Power were the result of lower effective income taxes and a higher allowed ROE. The cumulative impact of the increase in the regulator-approved allowed ROE, effective January 1, 2012, was recorded in the second quarter of 2012. The increase in corporate expenses was due to approximately $4 million ($3 million after tax) of costs incurred during the second quarter of 2012 related to the pending acquisition of CH Energy Group and a lower income tax recovery, partially offset by a foreign exchange gain of approximately $1.5 million recognized in the second quarter of 2012. Decreased earnings at the FortisBC Energy companies mainly related to lower-than-expected customer additions in 2012 and lower capitalized AFUDC, partially offset by higher gas transportation volumes to industrial customers. A 7% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the issuance of common equity mid-2011, had the impact of tempering earnings per common share in the second quarter of 2012.

March 2012/March 2011: Net earnings attributable to common equity shareholders were $121 million, or $0.64 per common share, for the first quarter of 2012 compared to earnings of $116 million, or $0.66 per common share, for the first quarter of 2011. The increase in earnings was mainly due to higher contribution from the FortisBC Energy companies, increased non-regulated hydroelectric production in Belize associated with higher rainfall, and higher earnings at Newfoundland Power and Maritime Electric, mainly as a result of increased electricity sales and lower effective corporate income taxes. The increase in earnings was partially offset by the impact of the expiry of the PBR mechanism on December 31, 2011 at FortisBC Electric and the timing of certain operating expenses at the utility in 2012, higher corporate expenses and an approximate $1 million gain on the sale of property at FortisAlberta during the first quarter of 2011. The increase in earnings at the FortisBC Energy companies mainly related to the favourable impact of the difference in the timing of recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012, rate base growth and higher gas transportation volumes to industrial customers, partially offset by lower-than-expected customer additions in 2012 and lower capitalized AFUDC. The increase in corporate expenses was the result of approximately $4 million ($4 million after tax) of costs incurred during the first quarter of 2012 related to the pending acquisition of CH Energy Group and a $1.5 million foreign exchange loss, partially offset by lower finance charges. An 8% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the issuance of common equity mid-2011, had the impact of tempering earnings per common share in the first quarter of 2012.

MANAGEMENT'S EVALUATON OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2012 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2012 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2012, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

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

Approval by the NYSPSC of the Corporation's acquisition of CH Energy Group is the last significant regulatory matter required to close the transaction. The transaction is anticipated to close during the second quarter of 2013. With the acquisition of CH Energy Group, the Corporation's regulated midyear rate base will increase to approximately $10 billion.

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

OUTSTANDING SHARE DATA

As at March 19, 2013, the Corporation had issued and outstanding 192.5 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 10.0 million First Preference Shares, Series H; 8.0 million First Preference Shares, Series J; and 18.5 million Subscription Receipts. 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 such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options, First Preference Shares, Series C and E, and Subscription Receipts were converted as at March 19, 2013 is as follows.

Conversion of Securities into Common Shares

As at March 19, 2013 *(Unaudited)* **Security**	**Number of Common Shares** *(millions)*
Stock Options	5.4
First Preference Shares, Series C	3.9
First Preference Shares, Series E	6.3
Subscription Receipts	18.5
Total	34.1

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

Financials

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Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2012 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States. Financial information contained elsewhere in the 2012 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2012 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2012 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2012 Annual Consolidated Financial Statements and their report follows.

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

Barry V. Perry
Vice President, Finance and Chief Financial Officer, Fortis Inc.

St. John's, Canada

Independent Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2012 and 2011 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

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

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

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

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

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2012 and 2011 and its financial performance and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
March 20, 2013

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

ASSETS	2012	2011
Current assets		*(Note 37)*
Cash and cash equivalents	**$ 154**	$ 87
Accounts receivable *(Note 5)*	**587**	638
Prepaid expenses	**18**	19
Inventories *(Note 6)*	**133**	134
Regulatory assets *(Note 7)*	**185**	230
Deferred income taxes *(Note 26)*	**16**	24
	1,093	1,132
Other assets *(Note 9)*	**200**	184
Regulatory assets *(Note 7)*	**1,515**	1,388
Deferred income taxes *(Note 26)*	**–**	8
Utility capital assets *(Note 10)*	**9,623**	9,018
Income producing properties *(Note 11)*	**626**	594
Intangible assets *(Note 12)*	**325**	325
Goodwill *(Note 13)*	**1,568**	1,565
	$ 14,950	$ 14,214
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 33)*	**$ 136**	$ 159
Accounts payable and other current liabilities *(Note 14)*	**966**	977
Regulatory liabilities *(Note 7)*	**72**	51
Current installments of long-term debt *(Note 15)*	**117**	103
Current installments of capital lease and finance obligations *(Note 16)*	**7**	7
Deferred income taxes *(Note 26)*	**10**	8
	1,308	1,305
Other liabilities *(Note 17)*	**622**	564
Regulatory liabilities *(Note 7)*	**681**	612
Deferred income taxes *(Note 26)*	**718**	676
Long-term debt *(Note 15)*	**5,783**	5,685
Capital lease and finance obligations *(Note 16)*	**428**	429
	9,540	9,271
Shareholders' equity		
Common shares [(1)] *(Note 18)*	**3,121**	3,036
Preference shares *(Note 20)*	**1,108**	912
Additional paid-in capital	**15**	14
Accumulated other comprehensive loss *(Note 21)*	**(96)**	(95)
Retained earnings	**952**	868
	5,100	4,735
Non-controlling interests *(Note 22)*	**310**	208
	5,410	4,943
	$ 14,950	$ 14,214

[(1)] no par value; unlimited authorized shares; 191.6 million and 188.8 million issued and outstanding as at December 31, 2012 and 2011, respectively

Commitments *(Note 34)*
Expropriated Assets *(Note 35)*
Contingent Liabilities *(Note 36)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2012**	2011
Revenue	**$ 3,654**	$ 3,738
Expenses		
Energy supply costs	**1,522**	1,697
Operating	**868**	850
Depreciation and amortization	**470**	416
	2,860	2,963
Operating income	**794**	775
Other income, net *(Note 24)*	**4**	38
Finance charges *(Note 25)*	**366**	363
Earnings before income taxes	**432**	450
Income taxes *(Note 26)*	**61**	84
Net earnings	**$ 371**	$ 366
Net earnings attributable to:		
Non-controlling interests	**$ 9**	$ 9
Preference equity shareholders	**47**	46
Common equity shareholders	**315**	311
	$ 371	$ 366
Earnings per common share *(Note 19)*		
Basic	**$ 1.66**	$ 1.71
Diluted	**$ 1.65**	$ 1.70

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2012**	2011
Net earnings	**$ 371**	$ 366
Other comprehensive (loss) income		
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax *(Note 21)*	**(2)**	1
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity *(Notes 9 and 21)*	**–**	17
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 21)*	**1**	1
Unrealized employee future benefits losses, net of tax *(Notes 21 and 27)*	**–**	(6)
	(1)	13
Comprehensive income	**$ 370**	$ 379
Comprehensive income attributable to:		
Non-controlling interests	**$ 9**	$ 9
Preference equity shareholders	**47**	46
Common equity shareholders	**314**	324
	$ 370	$ 379

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2012**	2011
Operating activities		
Net earnings	**$ 371**	$ 366
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – utility capital assets and income producing properties	**424**	381
Amortization – intangible assets	**44**	38
Amortization – other	**2**	(3)
Deferred income taxes *(Note 26)*	**17**	4
Employee future benefits	**10**	18
Equity component of allowance for funds used during construction *(Note 24)*	**(7)**	(13)
Other	**(1)**	(1)
Change in long-term regulatory assets and liabilities	**38**	26
Change in non-cash operating working capital *(Note 30)*	**78**	99
	976	915
Investing activities		
Change in other assets and other liabilities	**–**	(45)
Capital expenditures – utility capital assets	**(1,053)**	(1,083)
Capital expenditures – income producing properties	**(35)**	(30)
Capital expenditures – intangible assets	**(42)**	(58)
Contributions in aid of construction	**68**	75
Proceeds on sale of utility capital assets and income producing properties *(Note 8)*	**3**	51
Business acquisitions, net of cash acquired *(Note 28)*	**(21)**	(25)
	(1,080)	(1,115)
Financing activities		
Change in short-term borrowings	**(22)**	(198)
Proceeds from long-term debt, net of issue costs	**124**	343
Repayments of long-term debt and capital lease and finance obligations	**(88)**	(40)
Net borrowings (repayments) under committed credit facilities	**71**	(145)
Advances from non-controlling interests	**106**	81
Subscription Receipts issue costs *(Notes 9 and 18)*	**(13)**	–
Issue of common shares, net of costs and dividends reinvested	**24**	345
Issue of preference shares, net of costs	**194**	–
Dividends		
Common shares, net of dividends reinvested	**(170)**	(151)
Preference shares	**(46)**	(46)
Subsidiary dividends paid to non-controlling interests	**(9)**	(9)
	171	180
Change in cash and cash equivalents	**67**	(20)
Cash and cash equivalents, beginning of year	**87**	107
Cash and cash equivalents, end of year	**$ 154**	$ 87

Supplementary Information to Consolidated Statements of Cash Flows *(Note 30)*

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Changes in Equity

FORTIS INC.

For the years ended December 31, 2012 and 2011 (in millions of Canadian dollars)	Common Shares	Preferences Shares	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 18)	*(Note 20)*		*(Note 21)*		*(Note 22)*	
As at January 1, 2012	**$ 3,036**	**$ 912**	**$ 14**	**$ (95)**	**$ 868**	**$ 208**	**$ 4,943**
Net earnings	**–**	**–**	**–**	**–**	**362**	**9**	**371**
Other comprehensive loss	**–**	**–**	**–**	**(1)**	**–**	**–**	**(1)**
Preference share issue	**–**	**196**	**–**	**–**	**–**	**–**	**196**
Common share issues	**85**	**–**	**(3)**	**–**	**–**	**–**	**82**
Stock-based compensation	**–**	**–**	**4**	**–**	**–**	**–**	**4**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**106**	**106**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**(4)**	**(4)**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(9)**	**(9)**
Dividends declared on common shares ($1.21 per share)	**–**	**–**	**–**	**–**	**(231)**	**–**	**(231)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(47)**	**–**	**(47)**
As at December 31, 2012	**$ 3,121**	**$ 1,108**	**$ 15**	**$ (96)**	**$ 952**	**$ 310**	**$ 5,410**
As at January 1, 2011	$ 2,575	$ 912	$ 12	$ (108)	$ 774	$ 162	$ 4,327
Net earnings	–	–	–	–	357	9	366
Other comprehensive income	–	–	–	13	–	–	13
Common share issues	461	–	(2)	–	–	–	459
Stock-based compensation	–	–	4	–	–	–	4
Advances from non-controlling interests	–	–	–	–	–	81	81
Foreign currency translation impacts	–	–	–	–	–	3	3
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(9)	(9)
Expropriation of Belize Electricity *(Notes 9 and 35)*	–	–	–	–	–	(38)	(38)
Dividends declared on common shares ($1.17 per share)	–	–	–	–	(217)	–	(217)
Dividends declared on preference shares	–	–	–	–	(46)	–	(46)
As at December 31, 2011	$ 3,036	$ 912	$ 14	$ (95)	$ 868	$ 208	$ 4,943

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

1. Description of the Business

Nature of Operations

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

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

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

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI").

FEI is the largest distributor of natural gas in British Columbia, serving more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC Electric component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant ("Brilliant Plant") and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Comprised of Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies (Note 28).

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 150 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2011 – 60%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Comprised of FortisTCI Limited ("FortisTCI"), Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") and Turks and Caicos Utilities Limited ("TCU"), which was acquired in August 2012, (collectively "Fortis Turks and Caicos") (Note 28). Each of the Fortis Turks and Caicos utilities is an integrated electric utility and, combined, have a diesel-powered generating capacity of 76 MW. Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through FortisTCI and to South Caicos through Atlantic. Fortis Turks and Caicos also provides electricity to Grand Turk and Salt Cay through TCU.

c. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. Fortis held an approximate 70% controlling ownership interest in Belize Electricity up to June 20, 2011. As of June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011 (Notes 9, 33 and 35).

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Comprised of the 25-MW Mollejon, 7-MW Chalillo and 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Comprised of six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall. Effective July 1, 2012, the legal ownership of the hydroelectric generating facilities in eastern Ontario was transferred from Fortis Properties to Fortis Generation East LLP, a limited liability partnership directly held by Fortis.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Fortis Properties holds directly a 51% interest in the Exploits Partnership and Abitibi holds the remaining 49% interest. Output from the generating facilities is being sold to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement ("PPA") expiring in 2033. In December 2008 the Government of Newfoundland and Labrador expropriated the hydroelectric assets and water rights of the Exploits Partnership. As a result of no longer controlling the cash flows and operations of the Exploits Partnership, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership effective February 2009 (Note 35).

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract set to expire in the fourth quarter of 2013. Non-regulated generation operations in British Columbia also include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, in late 2010. The Waneta Expansion is expected to come into service in spring 2015.

e. *Upstate New York:* Comprised of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upstate New York, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces. Fortis Properties also owns and operates approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada (Note 28).

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 finance charges, comprised of interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI"); dividends on preference shares; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and related income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP") and FortisBC Alternative Energy Services Inc. ("FAES"). CWLP is a non-regulated shared-services business in which FHI holds a 30% interest. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies.

The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011. CWLP's financial results were recorded using the equity method of accounting. FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

Pending Acquisition

In February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from the FERC and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction.

Approval by the New York State Public Service Commission ("NYSPSC") of the Corporation's acquisition of CH Energy Group is the last significant regulatory matter required to close the transaction. Closing of the transaction is now anticipated during the second quarter of 2013. A Settlement Agreement among Fortis, CH Energy Group, NYSPSC staff, registered interveners and other parties was filed with the NYSPSC in January 2013. The parties to the Settlement Agreement have concluded that, based on the terms of the Settlement Agreement, the acquisition is in the public interest and have recommended approval by the NYSPSC (Notes 24, 34 and 36).

2. Nature of Regulation

The nature of regulation at the Corporation's utilities is as follows:

FortisBC Energy Companies and FortisBC Electric

The FortisBC Energy companies and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. FEI, FEVI, FEWI and FortisBC Electric operate under cost of service ("COS") regulation and, from time to time, performance-based rate-setting ("PBR") mechanisms for establishing customer rates as administered by the BCUC. The PBR mechanism for FEI expired on December 31, 2009 with a two-year phase-out for differences between forecasted capital expenditures and those actually spent prior to 2010. The PBR mechanism for FortisBC Electric expired on December 31, 2011.

The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

The utilities apply for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible to be deferred on the consolidated balance sheet for future collection from, or refund to, customers ("deferral account treatment") and/or through the operation of PBR mechanisms.

Under the previous PBR mechanisms, FEI customers equally shared achieved earnings above or below the allowed ROE and FortisBC Electric customers equally shared achieved earnings above or below the allowed ROE up to an achieved ROE that was 200 basis points above or below the allowed ROE. Any excess was subject to deferral account treatment. FortisBC Electric's portion of the PBR incentive was subject to the Company meeting certain performance standards and BCUC approval.

In November 2009 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to the FortisBC Energy companies' 2010/2011 Revenue Requirements Application ("RRA") and in April 2012 the BCUC issued its decision on the companies' 2012/2013 RRA. In December 2010 the BCUC approved an NSA pertaining to FortisBC Electric's 2011 RRA prepared under the operation of the PBR mechanism. In August 2012 the BCUC issued its decision on the Company's 2012/2013 RRA. As a result of the August 2012 rate decision, beginning in 2012, variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates at FortisBC Electric are subject to full deferral account treatment to be recovered from, or refunded to, customers in future rates and, therefore, did not impact earnings in 2012. Effective January 1, 2012, however, the flow-through treatment for finance charges, as was applied for in FortisBC Electric's 2012/2013 RRA, was denied by the regulator pursuant to its revenue requirements decision. Beginning in 2012, therefore, variances between actual finance charges from those forecasted in determining customer electricity rates impact earnings.

FEI's allowed ROE was 9.50% for 2012 (2011 – 9.50%) on a deemed capital structure of 40% common equity. FEVI's and FEWI's allowed ROEs were 10.00% for 2012 (2011 – 10.00%) on deemed capital structures of 40% common equity. FortisBC Electric's allowed ROE was 9.90% for 2012 (2011 – 9.90%) on a deemed capital structure of 40% common equity.

The allowed ROEs for 2011 and 2012 were set by the BCUC for FEI, FEVI and FEWI and FortisBC Electric. The former automatic adjustment formula used to establish ROEs on an annual basis no longer applies until reviewed further by the BCUC. As initiated by the BCUC in early 2012, a Generic Cost of Capital ("GCOC") Proceeding occurred during 2012 with an oral hearing completed in December on the first phase of the GCOC Proceeding. The items being reviewed in the GCOC Proceeding include: (i) the appropriate cost of capital for a benchmark low-risk utility, effective January 1, 2013, which includes capital structure, ROE and interest on debt; (ii) the establishment of a benchmark ROE based on a benchmark low-risk utility effective from January 1, 2013 through December 31, 2013 for the initial transition year; (iii) the determination of whether a return to an ROE automatic adjustment mechanism is warranted, which would be implemented January 1, 2014 or, if not warranted, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013; (iv) a generic methodology on how to establish each utility's cost of capital in reference to the cost of capital for a benchmark low-risk utility; (v) a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt; and (vi) for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism and, if not warranted, a future regulatory process will be set on how the deemed interest rate would be adjusted beyond December 31, 2013.

The BCUC has also determined that a second, subsequent phase be added to the GCOC Proceeding to determine an appropriate allowed ROE and capital structure for all other regulated utilities in British Columbia once the benchmark utility has been established in the first phase of the GCOC Proceeding. FEI has been designated as the benchmark utility. FEVI, FEWI and FortisBC Electric will have their allowed ROEs and capital structures determined in the second phase of the GCOC Proceeding. A decision on the benchmark utility, FEI, is expected mid-2013. Effective January 1, 2013, as ordered by the BCUC in December 2012, the current allowed ROE and capital structure for FEI and all other regulated entities in British Columbia that rely on the benchmark utility to establish rates are to be maintained and made interim. The result of the GCOC Proceeding could materially impact the earnings of the FortisBC Energy companies and FortisBC Electric.

FortisAlberta
FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

In 2011 and 2012 FortisAlberta operated under COS regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75% for 2012 (2011 – 8.75%) on a deemed capital structure of 41% common equity. The Company applied for tariff revenue based on estimated COS. Once the tariff was approved, it was not adjusted as a result of actual COS being different from that which was applied for, other than for certain prescribed costs that were eligible for deferral account treatment.

In April 2012 the AUC issued its decision on FortisAlberta's NSA pertaining to the Company's 2012 RRA. The most significant impact of the decision was the discontinuance in 2012 of the deferral of transmission volume variances associated with the Company's Alberta Electric System Operator ("AESO") charges deferral account, which had an approximate $8.5 million favourable impact on net earnings in 2012.

In December 2011 the AUC issued its decision on its 2011 GCOC Proceeding establishing the allowed ROE at 8.75% for 2011 and 2012, and at 8.75% for 2013 on an interim basis. A GCOC Proceeding initiated by the AUC in October 2012 is expected to commence later in 2013 and includes: (i) a determination of the allowed ROE for 2013; (ii) whether a formulaic ROE automatic mechanism should be re-established; and (iii) whether the AUC's PBR Decision or other decisions require the adjustment of the allowed ROE or equity component of the total capital structure as a result of any change in risk.

For a five-year term commencing January 1, 2013, FortisAlberta's distribution rates will be established annually under a PBR mechanism.

2. Nature of Regulation (cont'd)

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power.

Newfoundland Power operates under COS regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecasted rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined.

Generally the utility's allowed ROE is adjusted, between test years, annually through the operation of an automatic adjustment formula for forecasted changes in long-term Canada bond rates. In December 2011 the PUB approved Newfoundland Power's application to suspend the operation of the ROE automatic adjustment formula for 2012 and complete a full cost of capital review for 2012. In June 2012 the PUB approved an increase in the allowed ROE to 8.80% for 2012 from 8.38% for 2011, based on a deemed capital structure of 45% common equity. The PUB approved the deferred recovery of approximately $2.5 million (before tax), representing the difference between the 8.38% ROE reflected in customer electricity rates for 2012 and the final approved ROE of 8.80% for 2012.

Newfoundland Power applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

In September 2012 Newfoundland Power filed a General Rate Application for the purpose of setting 2013/2014 customer electricity rates and cost of capital. The application is currently under review by the PUB and a public hearing on the application concluded in February 2013.

Maritime Electric

Maritime Electric operates under a COS regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), which covers the period March 1, 2011 to February 28, 2013, and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("*Accord Continuation Act*"), which covers the period March 1, 2013 to February 29, 2016.

IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a targeted capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75% for 2012 (2011 – 9.75%) on a targeted minimum capital structure of 40% common equity.

In November 2010 Maritime Electric signed the *PEI Energy Accord* ("Accord") with the Government of PEI. Under the terms of the Accord, the Government of PEI assumed responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to Maritime Electric's 4.7% entitlement from the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011, during its refurbishment period, which ended in fall 2012. Maritime Electric also signed a five-year energy purchase agreement with NB Power, effective March 1, 2011. As a result of the Accord and the impact of the new energy purchase agreement, energy supply costs decreased and customer electricity rates were lowered overall by approximately 14.0%, effective March 1, 2011, at which time a two-year customer rate freeze occurred. In December 2012 the *Accord Continuation Act* was enacted, which sets out the inputs, rates and other terms for the continuation of the Accord for an additional three years covering the period March 1, 2013 through February 29, 2016. Over the three-year period, increases in electricity costs for a typical residential customer have been set at 2.2% annually and Maritime Electric's allowed ROE has been capped at 9.75% each year.

Maritime Electric applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the OEB.

Canadian Niagara Power's allowed ROE was 8.01% for 2012 (2011 – 8.01%) on a deemed capital structure of 40% common equity. Electricity distribution rates for 2012 and 2011 were based upon a 2009 historical test year. The OEB issued final decisions in March 2011 for operations in Port Colborne and in April 2011 for operations in Fort Erie and Gananoque related to Canadian Niagara Power's Third-Generation IRM applications for customer distribution rates effective May 1, 2011.

Notes to Consolidated Financial Statements

The OEB issued a final decision in April 2012 on Canadian Niagara Power's Third-Generation IRM application for customer distribution rates effective May 1, 2012. In November 2012 the OEB issued a decision on Canadian Niagara Power's COS Application for electricity distribution rates effective January 1, 2013, using a 2013 forward test year, and the allowed ROE, as determined under the ROE automatic adjustment formula, was calculated at 8.93% for 2013 on a deemed capital structure of 40% equity.

Algoma Power's allowed ROE was 9.85% for 2012 (2011 – 9.85%) on a deemed capital structure of 40% common equity and the utility's electricity distribution rates for 2011 and 2012 were based upon forecasted 2011 costs. In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution COS Application for rates effective December 2010 through December 2011. In March 2012 the OEB issued its final decision on Algoma Power's Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. In October 2012 Algoma Power filed a Third-Generation IRM application with the OEB for customer electricity distribution rates, effective January 1, 2013. In December 2012 the OEB issued an order making Algoma Power's customer rates for 2012 interim rates for 2013, until a final rate order is issued on 2013 customer rates. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario.

Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth, customer growth and premises vacancies.

Caribbean Utilities
Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The non-exclusive generation licence is for a period of 21.5 years, expiring September 2029. The licences detail the role of the Electricity Regulatory Authority ("ERA"), which oversees all licences, establishes and enforces licence standards, reviews the rate cap adjustment mechanism ("RCAM") and annually approves capital expenditures.

The licences contain the provision for an RCAM based on published consumer price indices. Effective June 1, 2011, Caribbean Utilities' base customer rates remained unchanged as a result of the annual operation of the RCAM. Effective June 1, 2012, the ERA approved an increase in Caribbean Utilities' base customer electricity rates by 0.7%, due to the annual operation of the RCAM as a result of changes in the applicable consumer price indices and the utility's achieved allowed rate of return on rate base assets ("ROA") for 2011.

Customer electricity rates for 2012 translated into a targeted ROA in the range of 7.25% to 9.25% (2011 – 7.75% to 9.75%).

Fortis Turks and Caicos
FortisTCI and Atlantic operate under 50-year licences expiring in 2037 and 2036, respectively. TCU operates under a 50-year licence expiring in 2036. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide the utilities with an allowed ROA of 17.50% for FortisTCI and Atlantic, and 15% for TCU (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall").

Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2012 calculated the combined Allowable Operating Profit, inclusive of TCU, for 2012 to be $34 million (US$34 million) and the combined Cumulative Shortfall, inclusive of TCU, at December 31, 2012 to be $105 million (US$105 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses.

The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

In February 2012 the Interim Government of the Turks and Caicos Islands ("Interim Government") approved an approximate 26% increase in electricity rates, effective April 1, 2012, for FortisTCI's large hotel customers. In addition, other qualitative enhancements to the franchise were also achieved, including: (i) improved wording in the Electricity Rate Regulation; (ii) an approved increase in kilowatt hour consumption thresholds for both medium- and large-sized hotels; (iii) an expansion of service territory to cover all of the Caicos Islands, except for areas currently serviced by private suppliers' licences, with new 25-year licences issued for the expanded service territory; and (iv) the discontinuance of the government subsidization of Atlantic's South Caicos operations.

Negotiations between FortisTCI and the Interim Government occurred during the third quarter of 2012, with FortisTCI presenting a new regulatory framework proposal to the Interim Government. A third-party consultant was engaged by the Interim Government to review the proposal and provide recommendations. No agreement was reached with the Interim Government; however, management expects to continue dialogue on regulatory reform with the newly elected Government.

3. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated public utilities include specific accounting guidance for regulated operations, as outlined in Note 2 and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control. All material intercompany transactions have been eliminated in the consolidated financial statements.

An evaluation of subsequent events through to March 20, 2013, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2012.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories, consisting of gas and fuel in storage and materials and supplies, are measured at the lower of average cost and market value.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation, with the following exceptions for rate-setting purposes: (i) utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost; (ii) utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost; and (iii) utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 1986 for FortisTCI and Atlantic and as at April 1986 for TCU. Subsequent additions at Fortis Turks and Caicos are at cost, including the distribution systems on Middle, North and South Caicos and Grand Turk and Salt Cay, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by licences for US$4.00, in aggregate, as valued in the books of the utilities.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

FortisOntario and Fortis Turks and Caicos recognize non-asset retirement obligation ("non-ARO") removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-ARO removal costs in depreciation, as requested in their 2012/2013 RRA and subsequently approved by the regulator in its April 2012 decision. The accrual of estimated non-ARO removal costs is included in depreciation and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Prior to 2012 estimated non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses with variances between actual non-ARO removal costs and those forecasted for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. During 2012 non-ARO removal costs of $20 million were accrued by the FortisBC Energy companies as part of depreciation and actual non-ARO removal costs of $16 million, net of salvage proceeds, were incurred and recognized against the long-term regulatory liability (Note 7 *(xviii)*). During 2011 actual non-ARO removal costs of approximately $17 million, net of salvage proceeds, were incurred by the FortisBC Energy companies, with $12 million recognized in operating expenses and $5 million deferred as a regulatory asset.

Each of FortisAlberta, Newfoundland Power and Maritime Electric also accrue estimated non-ARO removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 7 *(xviii)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred (Note 37). During 2012 non-ARO removal costs of $47 million (2011 – $52 million), were accrued by the above-noted utilities as a part of depreciation.

As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. During 2012 actual non-ARO removal costs of approximately $4 million (2011 – $5 million), net of salvage proceeds of less than $1 million (2011 – less than $1 million), were incurred at FortisBC Electric.

Utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer gas and electricity rates. The loss charged to accumulated depreciation in 2012 was approximately $20 million (2011 – $15 million).

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 7 *(ix)*).

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets be recognized immediately in earnings.

As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator.

As required by their respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component in the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 25) and the equity component of AFUDC is reported as other income, net (Note 24). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta the cost of utility capital assets also include AESO contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

As approved by the regulator, FEVI has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FEVI increases both utility capital assets and long-term debt (Note 34).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. When put into service, the inventories are depreciated using the straight-line method based on the estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments are capitalized.

3. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets (cont'd)

Utility capital assets are being depreciated using the straight-line method based on the estimated service lives of the capital assets. Depreciation rates for 2012 ranged from 1.3% to 43.2% (2011 – 0.4% to 33.3%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2012 was 3.3% (2011 – 3.5%).

The impact of the above-noted changes in depreciation rates on depreciation expense, as well as the inclusion, effective January 1, 2012, in depreciation rates of the accrual of estimated non-ARO removal costs at the FortisBC Energy companies, has been reflected in the utilities' approved revenue requirements and resulting customer rates. The FortisBC Energy companies are also deferring variances between actual depreciation expense and that forecasted in determining customer gas rates, effective January 1, 2012, as approved by the regulator (Note 7 *(xxiv)*).

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows:

	2012		2011	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Gas	**4–68**	**36**	4–62	38
Electricity	**5–65**	**27**	5–75	26
Transmission				
Gas	**6–70**	**39**	4–82	35
Electricity	**20–65**	**26**	20–65	26
Generation	**5–75**	**31**	5–75	32
Other	**3–70**	**9**	3–70	10

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost less accumulated depreciation, where applicable. Buildings are being depreciated using the straight-line method over an estimated useful life of 60 years. Fortis Properties depreciates tenant inducements over the initial terms of the leases to which they relate, except where a writedown is required to reflect permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is depreciated on a straight-line basis over a range of 2 to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred, while replacements and betterments are capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. The cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset. Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; and customer contracts.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually either individually or at the reporting unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at FEI, FEVI and FortisBC Electric. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Effective January 1, 2012, the Corporation early adopted the amendments to Accounting Standards Codification ("ASC") Topic 350, *Intangibles – Goodwill and Other* ("ASC Topic 350") related to the testing for impairment of indefinite-lived intangible assets.

The amended standard allows entities testing indefinite-lived intangible assets for impairment to have the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required. Previous guidance in ASC Topic 350 required an entity to test indefinite-lived intangible assets for impairment, on at least an annual basis, by calculating fair value and comparing the fair value to the carrying amount of the assets. If the carrying amount of an indefinite-lived intangible asset exceeded its fair value, an impairment charge was required.

Impairment testing for indefinite-lived intangible assets is carried out at the reporting unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer gas and electricity rates as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets was below their carrying value. No such event or changes in circumstances occurred during 2012 or 2011 and there were no impairment provisions required in either year.

Effective January 1, 2012, Fortis has adopted the approach for the annual testing for goodwill impairment, as disclosed in this Note under "Goodwill", for its annual testing of impairment for indefinite-lived intangible assets.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

Amortization rates for 2012 ranged from 1.5% to 43.0% (2011 – 1.0% to 38.8%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2012		2011	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**5–10**	**5**	5–10	6
Land, transmission and water rights	**31–75**	**35**	31–75	38
Franchise fees, customer contracts and other	**10–100**	**23**	4–100	15

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gain or loss charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer gas and electricity rates.

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets in a regulatory deferral account for recovery from, or refund to, customers in future rates, subject to regulatory approval (Note 7 *(ix)*).

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets be recognized immediately in earnings.

3. Summary of Significant Accounting Policies (cont'd)

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2012 and 2011.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer gas and electricity rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 350 related to the testing for impairment of goodwill. The amended standard allows entities testing goodwill for impairment to have the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

Prior to adopting amendments to ASC Topic 350, fair value of each of the Corporation's reporting units, to which goodwill was allocated, was estimated on an annual basis by an independent external consultant. Upon adopting the above-noted amendments, Fortis performs an annual internal quantitative assessment for each reporting unit and, for those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an independent external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an independent external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each reporting unit estimated by an independent external consultant once every three years.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or changes in circumstances occurred during 2012 or 2011 and no impairment provisions were required in either year.

In calculating for goodwill impairment, Fortis determines those reporting units which will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount.

The primary method for estimating fair market value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by the independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees; and defined contribution pension plans, including group Registered Retirement Savings Plans ("RRSPs") for employees. The plans are accounted for in accordance with ASC Topic 715, *Compensation-Retirement Benefits*. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at the FortisBC Energy companies and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension and other non-pension post-employment benefit ("OPEB") plans, measured as the difference between the fair value of the plan assets and the benefit obligation, is recognized on the Corporation's consolidated balance sheet.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 *(ii)*).

At the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, FortisOntario and Maritime Electric, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with the defined benefit plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 7 *(ii)*). At Fortis, FHI and Caribbean Utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with the defined benefit plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

Other Post-Employment Benefit Plans

The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEBs through defined benefit plans, including certain health and dental coverage, for qualifying members. The accumulated benefit obligation and the value of the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation at the beginning of the fiscal year and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of FortisAlberta, as discussed below, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a separate component of shareholders' equity within accumulated other comprehensive loss.

Notes to Consolidated Financial Statements

3. Summary of Significant Accounting Policies (cont'd)

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 23). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records the liabilities associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans at their fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period. The fair value of the PSU liability is also based on expected payout based on historical performance in accordance with defined metrics of each grant, where applicable, and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, BECOL and FortisUS Energy is the US dollar; while up to June 20, 2011, Belize Electricity's reporting currency was the Belizean dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00. The exchange rate in effect as at December 31, 2012 was US$1.00=CDN$0.995 (December 31, 2011 – US$1.00=CDN$1.02). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive loss until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income.

Effective June 20, 2011, as a result of the expropriation of Belize Electricity by the GOB, the Corporation's asset associated with its previous investment in Belize Electricity (Notes 9, 33 and 35) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Derivative Instruments and Hedging Activities

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates, and fuel and natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at December 31, 2012, the Corporation's derivative instruments consisted of fuel option contracts, natural gas swap and option contracts and gas purchase contract premiums.

Mark-to-market is the default accounting treatment for all derivative instruments unless they qualify, and are designated, for one of the elective accounting treatments. Mark-to-market requires the derivative instrument to be recorded at fair value with changes in fair value recognized in earnings. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria, both at the time of designation and on an ongoing basis. The elective accounting treatments include: (i) cash flow hedges; (ii) fair value hedges; and (iii) normal purchase normal sale arrangements.

The Corporation continually assesses its contracts, including its PPAs, to determine whether they meet the criteria of a derivative and, if so, whether they qualify for elective accounting treatment.

As at December 31, 2012, the Corporation's hedging relationships consisted of fuel option contracts, natural gas derivatives, gas purchase contract premiums and US dollar borrowings.

Fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. Any change in the fair value of the fuel option contracts, whether or not the contracts are in qualifying and designated hedging relationships, is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. Any change in the fair value of the natural gas derivatives, whether or not the derivatives are in qualifying and designated hedging relationships, is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in other comprehensive income.

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. The deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax is recovered or refunded in current customer rates, as prescribed by the respective regulator. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. The above utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected or refunded in customer rates once they become payable or receivable (Note 7 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs.

Any difference between the income tax expense or recovery recognized under US GAAP and that recovered from, or refunded to, customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. As at December 31, 2012, temporary differences related to investments in foreign subsidiaries were approximately $294 million (December 31, 2011 – $283 million). It is impractical to estimate the amount of income tax that might be payable if a reversal of temporary differences occurred. Where Tax Information Exchange Agreements ("TIEAs") are entered into force for Bermuda, the Cayman Islands and the Turks and Caicos Islands, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above as no taxes are payable on these earnings. When a TIEA is entered into for Belize, earnings from the Corporation's operations in Belize (i.e., BECOL) can also be repatriated to Canada on a tax-free basis. Negotiations with the Government of Canada and GOB commenced in June 2010.

3. Summary of Significant Accounting Policies (cont'd)

Income Taxes (cont'd)

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense. Investment tax credits are deducted from the related assets and amortized to expense as the related asset is recognized in earnings.

Sales Taxes

In the course of its operations, the Corporation and its subsidiaries collect sales taxes from its customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

Revenue Recognition

Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

Revenue from the sale of gas by the FortisBC Energy companies and electricity by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on an accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. As approved by the regulator for 2011, FortisAlberta was not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers were deferred to be recovered from, or refunded to, customers in future rates (Note 7 *(xvi)*). For 2012 the regulator did not approve the continuation of the deferral of transmission volume variances. In the absence of this deferral, FortisAlberta was subject to volume risk in 2012 on actual transmission costs relative to those charged to customers based on forecasted volumes and prices. The ability to defer transmission volume variances was reinstated by the regulator effective January 1, 2013.

FortisOntario's regulated operations primarily consist of the operations of Cornwall Electric, Canadian Niagara Power and Algoma Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power and Algoma Power are not bundled. At Canadian Niagara Power and Algoma Power, the cost of power and/or transmission is a flow through to customers and revenue associated with the recovery of these costs is tracked and recorded separately. The amount of transmission revenue tracked separately at Canadian Niagara Power and Algoma Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements.

The leases are primarily of a net nature, with tenants paying basic rent plus a pro-rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants are recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases are recognized in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations

Asset-retirement obligations ("AROs"), including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

As at December 31, 2012, FortisBC Electric has recognized an approximate $3 million ARO (December 31, 2011 – $4 million), which has been classified as a long-term other liability (Note 17) with the offset to utility capital assets. Changes in the obligation at FortisBC Electric, due to the passage of time, are recognized as a regulatory asset using the effective interest method.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Fair Value Measurement

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures*. The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP and International Financial Reporting Standards ("IFRS"). The amendments did not change what items are measured at fair value but instead made various changes to the guidance pertaining to how fair value is measured. The changes did not have a material impact on the Corporation's consolidated financial statements for the year ended December 31, 2012 (Note 32).

Presentation of Comprehensive Income

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 220, *Comprehensive Income*. The amended standard requires entities to report components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate but consecutive statements. The option to report other comprehensive income and its components in the statement of shareholders' equity has been eliminated. Although the new guidance changes the presentation of comprehensive income, there are no changes to the components that are recognized in net income or other comprehensive income under existing guidance. The amended standard did not change the Corporation's financial statement presentation of comprehensive income, which is reported in a separate but consecutive statement.

3. Summary of Significant Accounting Policies (cont'd)

Use of Accounting Estimates

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 reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Income Producing Properties, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 7 and 36.

4. Future Accounting Pronouncements

Disclosures About Offsetting Assets and Liabilities

Effective January 1, 2013, the Corporation is adopting the amendments to ASC Topic 210, *Balance Sheet – Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update No. 2011-11. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The amended disclosures are intended to assist financial statement users in understanding significant quantitative differences between balance sheets prepared under US GAAP and IFRS. Fortis does not expect that the adoption of the above amendments will have a material impact on its consolidated financial statements.

5. Accounts Receivable

(in millions)	**2012**	2011
Accounts receivable – trade	**$ 544**	$ 604
Allowance for doubtful accounts	**(19)**	(16)
Income tax receivable	**11**	–
Other	**51**	50
	$ 587	$ 638

Other accounts receivable as at December 31, 2012 and 2011 consisted mainly of customer billings for non-core services, collateral deposits for gas purchases and residential tax credits at the FortisBC Energy companies.

6. Inventories

(in millions)	**2012**	2011
Gas and fuel in storage	**$ 115**	$ 115
Materials and supplies	**18**	19
	$ 133	$ 134

7. Regulatory Assets and Liabilities

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2012**	2011	**Remaining recovery period (Years)**
Regulatory assets		*(Note 37)*	
Deferred income taxes *(i)*	**$ 713**	$ 647	To be determined
Employee future benefits *(ii)*	**498**	443	Various
Deferred lease costs – FortisBC Electric *(iii)*	**77**	70	11–44
Rate stabilization accounts – electric utilities *(iv)*	**57**	55	Various
Deferred energy management costs *(v)*	**50**	36	1–10
Rate stabilization accounts – FortisBC Energy companies *(vi)*	**48**	112	1
Point Lepreau replacement energy deferral *(vii)*	**47**	47	1
Deferred operating overhead costs *(viii)*	**32**	22	Various
Deferred net losses on disposal of utility capital assets and intangible assets *(ix)*	**27**	17	19
Customer Care Enhancement Project cost deferral *(x)*	**24**	13	7–8
Income taxes recoverable on OPEB plans *(xi)*	**23**	22	Various
Alternative energy projects cost deferral *(xii)*	**18**	8	To be determined
Whistler pipeline contribution deferral *(xiii)*	**14**	16	47
Deferred development costs for capital projects *(xiv)*	**10**	11	19
Deferred costs – smart meters *(xv)*	**9**	8	To be determined
AESO charges deferral *(xvi)*	**–**	44	–
Other regulatory assets *(xvii)*	**53**	47	Various
Total regulatory assets	**1,700**	1,618	
Less: current portion	**(185)**	(230)	1
Long-term regulatory assets	**$ 1,515**	$ 1,388	
Regulatory Liabilities			
Non-ARO removal cost provision *(xviii)*	**$ 486**	$ 455	To be determined
Rate stabilization accounts – FortisBC Energy companies *(vi)*	**117**	94	Various
Rate stabilization accounts – electric utilities *(iv)*	**46**	33	Various
AESO charges deferral *(xvi)*	**44**	12	1–5
Deferred income taxes *(i)*	**12**	12	1
Deferred interest *(xix)*	**9**	11	1–3
Income tax variance deferral *(xx)*	**7**	12	Various
Meter reading and customer service variance deferral *(xxi)*	**6**	–	To be determined
Southern Crossing Pipeline deferral *(xxii)*	**4**	8	3
PBR incentive liabilities *(xxiii)*	**1**	7	2
Other regulatory liabilities *(xxiv)*	**21**	19	Various
Total regulatory liabilities	**753**	663	
Less: current portion	**(72)**	(51)	1
Long-term regulatory liabilities	**$ 681**	$ 612	

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

7. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities

(i) Deferred Income Taxes

The Corporation recognizes deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*.

The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the income taxes become payable or receivable. As at December 31, 2012, $115 million (December 31, 2011 – $104 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) Employee Future Benefits

The regulatory asset associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated subsidiaries, which have met the requirements in accordance with US GAAP to be recognized as a regulatory asset and which are expected to be recovered from customers in future rates (Note 27).

At the Corporation's regulated subsidiaries, as approved by the respective regulators, differences between pension and OPEB costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset.

Prior to 2011, as required by the regulator, Newfoundland Power accounted for OPEB costs on a cash basis. In December 2010 the regulator ordered Newfoundland Power to include OPEB costs in the determination of customer rates based on the accrual method of accounting, effective January 1, 2011. The resulting regulatory OPEB asset of $53 million is being amortized and collected from customers in rates equally over 15 years, which commenced in 2011, as required by the regulator.

As at December 31, 2012, FortisBC Electric's and FortisOntario's regulatory assets associated with employee future benefits totalling $74 million and $20 million, respectively (December 31, 2011 – $68 million and $14 million, respectively), were not subject to a regulatory return.

(iii) Deferred Lease Costs – FortisBC Electric

The depreciation of FortisBC Electric's Brilliant Power Purchase Agreement ("BPPA") asset under capital lease and interest expense associated with the BPPA capital lease obligation are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2012 includes $63 million (December 31, 2011 – $56 million) of deferred BPPA lease costs that are expected to be recovered from customers in future rates over the term of the BPPA lease, which ends in 2056.

FortisBC Electric also defers lease costs associated with the Brilliant Terminal Station ("BTS"). The capital cost of the BTS, the cost of financing the BTS obligation and the related operating expense are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BTS lease. The regulatory asset balance as at December 31, 2012 includes $6 million (December 31, 2011 – $6 million) of deferred lease costs related to the BTS that are expected to be recovered from customers in future rates over the term of the BTS lease, which ends in 2041.

During 2012, of the $29 million (2011 – $29 million) of interest expense related to the BPPA and BTS capital lease obligations and the $6 million (2011 – $6 million) of depreciation expense related to the BPPA and BTS assets under capital lease, a total of $25 million (2011 – $24 million) was recognized in energy supply costs and $3 million (2011 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2011 – $8 million) deferred as a regulatory asset (Note 16).

FortisBC Electric also defers costs associated with the lease of the Trail office building. The depreciation expense and the imputed interest expense related to the Trail office building are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the lease agreement. The regulatory asset balance as at December 31, 2012 includes $8 million (December 31, 2011 – $8 million) of deferred lease costs that are expected to be recovered from customers in future rates over the term of the Trail office building lease, which ends in 2023. The terms of the lease agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

During 2012 approximately $1 million (2011 – $1 million) of interest expense related to the finance obligation associated with the lease of the Trail office building was recognized in operating expenses, as approved by the regulator (Note 16).

FortisBC Electric's deferred lease costs are not subject to a regulatory return.

(iv) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, Fortis Turks and Caicos, and, commencing in 2012, FortisBC Electric) are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. The rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecasted or predetermined level. Additionally, at Newfoundland Power, the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. The weather normalization account reduces the volatility in Newfoundland Power's year-to-year earnings that would otherwise result from fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, ranges from one to three years and is subject to periodic review by the respective regulatory authority.

The balance in Newfoundland Power's weather normalization account as at December 31, 2012 was a net regulatory liability of $7 million (December 31, 2011 – net regulatory liability of $7 million). The account balance should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB in 2008, a non-reversing asset balance of approximately $7 million of the weather normalization account was amortized equally over 2008 through 2012. The settlement period of the remaining balance of the weather normalization account is yet to be determined as it depends on weather conditions in the future.

Beginning in 2012, as approved by the regulator in its decision on FortisBC Electric's 2012/2013 RRA, variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates are subject to full deferral account treatment. As at December 31, 2012, these variances were in a liability position totalling $5 million and are expected to be approved for settlement in 2014 as a reduction to 2014 revenue requirements. The rate stabilization account at FortisBC Electric is also comprised of a $2 million liability amount related to the difference between the final approved and interim customer rate increase in 2012, which has been approved for settlement in 2013 as a reduction to 2013 revenue requirements.

As at December 31, 2012, $4 million in pre-2004 energy costs deferred as a regulatory asset in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a remaining recovery period of two years. Subsequent to 2003, annual deferral of energy costs to the ECAM account is being recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period. As at December 31, 2012, the post-2003 ECAM regulatory deferral at Maritime Electric was in a liability position totalling $28 million. In accordance with the Accord, which came into effect on March 1, 2011, $26 million of the post-2003 ECAM regulatory liability as at December 31, 2012 is expected to be refunded to customers in 2013. The remaining $2 million of the post-2003 ECAM regulatory liability as at December 31, 2012 is expected to be refunded to customers in 2014.

As at December 31, 2012, of the remaining balance of the rate stabilization accounts in a receivable position, $6 million and $24 million (December 31, 2011 – $5 million and $25 million) at FortisOntario and Caribbean Utilities, respectively, were not subject to a regulatory return.

(v) *Deferred Energy Management Costs*

The FortisBC Energy companies, FortisBC Electric, Newfoundland Power and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, the above regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 4 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

(vi) *Rate Stabilization Accounts – FortisBC Energy Companies*

The rate stabilization accounts at the FortisBC Energy companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, natural gas cost volatility and changes in the fair value of natural gas commodity derivative instruments.

At FEI a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecasted gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecasted natural gas costs. The CCRA also accumulates the changes in fair value of FEI's natural gas commodity derivative instruments. At FEVI a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on FEVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in fair value of FEVI's natural gas commodity derivative instruments.

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

7. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(vi) Rate Stabilization Accounts – FortisBC Energy Companies (cont'd)

The RSAM and MCRA are anticipated to be refunded through customer rates over a three-year period. The refund of the RSAM balance is dependent on annually approved rates and actual gas consumption volumes. The CCRA and GCVA accounts are anticipated to be fully recovered or refunded within the next fiscal year.

Beginning in 2010 a Revenue Surplus Deferral Account ("RSDA") was approved by the regulator for FEVI to accumulate differences between revenue collected from customers and actual COS, excluding variances from forecast related to operation and maintenance expenses. It is anticipated that the RSDA will be refunded to customers commencing in 2014.

The rate stabilization accounts at the FortisBC Energy companies are detailed as follows:

(in millions)	**2012**	2011
		(Note 37)
Current regulatory assets		
CCRA	**$ 16**	$ 73
GCVA	**32**	39
Total regulatory assets	**$ 48**	$ 112
Current regulatory liabilities		
MCRA	**$ 9**	$ 6
RSAM	**9**	8
	$ 18	$ 14
Long-term regulatory liabilities		
MCRA	**$ 9**	$ –
RSAM	**16**	16
RSDA	**74**	64
	$ 99	$ 80
Total regulatory liabilities	**$ 117**	$ 94

(vii) Point Lepreau Replacement Energy Deferral

Point Lepreau underwent a major refurbishment from 2008 through fall 2012. Maritime Electric had regulatory approval to defer the cost of incremental replacement energy related to Point Lepreau from 2008 through February 28, 2011, which totalled $47 million. Under the terms of the Accord and *Accord Continuation Act*, the Government of PEI assumed, effective March 1, 2011, responsibility for the cost of incremental replacement energy and monthly operating and maintenance costs related to Point Lepreau during the remainder of the refurbishment period.

It is expected that the $47 million regulatory asset will be assumed by the Government of PEI in 2013.

(viii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets.

(ix) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, effective January 1, 2010, gains and/or losses on the retirement or disposal of utility capital assets and intangible assets at the FortisBC Energy companies are being recorded in a regulatory deferral account to be recovered from customers in future rates. As part of its 2012/2013 RRA decision, the regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 20 years, which commenced in 2012.

(x) Customer Care Enhancement Project Cost Deferral

The Customer Care Enhancement Project cost deferral accumulated all incremental costs associated with the implementation of FEI's Customer Care Enhancement Project, which was substantially completed in January 2012. In its 2012/2013 RRA decision, the regulator also approved deferral treatment for variances from forecast for certain costs related to the customer care function. The regulatory asset is approved for recovery in customer rates over an eight-year period that commenced in 2012 for costs deferred in 2011 and will commence in 2013 for costs deferred in 2012.

(xi) *Income Taxes Recoverable on OPEB Plans*

At the FortisBC Energy companies and FortisBC Electric, the regulator allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the regulator, the tax effect of this timing difference is deferred as a separate regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates.

(xii) *Alternative Energy Projects Cost Deferral*

The alternative energy projects cost deferral at the FortisBC Energy companies represents costs, net of revenue, associated with the investment in alternative energy solutions. The recovery period of the regulatory asset is to be determined by the regulator at a future time and is expected to be recovered from current and future alternative energy services customers.

(xiii) *Whistler Pipeline Contribution Deferral*

The Whistler pipeline contribution deferral represents the capital contribution from FEWI to FEVI on completion of the natural gas pipeline to Whistler, as constructed by FEVI. The deferral is being recovered from FEWI's customers over a period of 50 years, which commenced in 2010, as approved by the regulator.

(xiv) *Deferred Development Costs for Capital Projects*

Deferred development costs for capital projects include costs for projects under development at the FortisBC Energy companies that are subject to regulatory approval for recovery in future customer rates. The majority of the balance relates to the project cost overrun incurred on the conversion of FEWI customer appliances from propane to natural gas, for which FEWI received a decision from the BCUC allowing these additional costs to be deferred and collected in FEWI customer rates over a period of 20 years, which commenced in 2012.

(xv) *Deferred Costs – Smart Meters*

In 2006 the Government of Ontario committed to install smart electricity meters in all Ontario residences and small commercial businesses by the end of 2010. FortisOntario is eligible to recover from customers in future customer rates all prudent and reasonable costs that were incurred related to this smart metering initiative. These deferred costs represent incremental operating, administrative and capital costs directly related to the smart metering initiative.

(xvi) *AESO Charges Deferral*

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2012, the regulatory liability primarily represented the over collection of costs. The settlement of the regulatory liability will be determined by the regulator in a future period.

(xvii) *Other Regulatory Assets*

Other regulatory assets relate to all of the Corporation's regulated utilities. The balance is comprised of various items, each individually less than $5 million. As at December 31, 2012, $42 million (December 31, 2011 – $42 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2012, $21 million (December 31, 2011 – $11 million) of the balance was not subject to a regulatory return.

(xviii) *Non-ARO Removal Cost Provision*

As required by the respective regulator, depreciation rates at FortisAlberta, Newfoundland Power, Maritime Electric, and effective January 1, 2012 at the FortisBC Energy companies, include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xix) *Deferred Interest*

The FortisBC Energy companies have interest deferral mechanisms, as approved by the regulator, which accumulate variances between actual and approved interest rates associated with long-term and short-term borrowings. The deferred interest is being refunded in customer rates over a rolling three-year period. The FortisBC Energy companies also have interest deferral mechanisms on rate stabilization accounts and gas inventory, which accumulate the difference between the actual and forecasted average balance of the rate stabilization accounts and gas inventory, multiplied by the composite interest rate. The deferred interest on the rate stabilization accounts of approximately $4 million is being refunded to customers over the same period as the underlying rate stabilization accounts, and deferred interest of less than $1 million on gas inventory is being refunded to customers over a rolling three-year period.

7. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xx) Income Tax Variance Deferral

The income tax variance deferral account at the FortisBC Energy companies accumulates the difference in income tax expense as a result of changes in tax laws, audit reassessments, accounting policy changes and changes in income tax rates for refund to customers in future rates over a one-year period, as approved by the regulator.

As ordered by the regulator, Maritime Electric has deferred the estimated potential income tax benefit associated with amendments to its income tax returns for the years 2007 through 2010. These amounts are to be deferred until such time as the amendments are confirmed by Canada Revenue Agency ("CRA") and the refunds are received by the Company.

(xxi) Meter Reading and Customer Service Variance Deferral

At the FortisBC Energy companies, variances between expenditures that are approved for recovery in customer rates and actual expenditures incurred for meter reading services and certain ongoing operating costs of the insourced activities related to the Customer Care Enhancement Project are permitted deferral account treatment, as approved by the regulator. The settlement of the regulatory liability will be determined by the regulator in a future period.

(xxii) Southern Crossing Pipeline Deferral

The above regulatory liability at the FortisBC Energy companies represents the difference between actual revenue received from third parties for the use of the Southern Crossing pipeline and that which has been approved by the regulator in revenue requirements. The deferral is being amortized over a rolling three-year period.

(xxiii) PBR Incentive Liabilities

FortisBC Electric's regulatory framework included a PBR mechanism that allowed for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to forecasted costs used to set customer rates. A portion of FortisBC Electric's regulatory PBR incentive liability was refunded to customers in 2011 and 2012, with the remaining balance of $1 million expected to be approved for settlement in 2014.

(xxiv) Other Regulatory Liabilities

Other regulatory liabilities relate to the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario. The balance is comprised of various items, each individually less than $5 million. As at December 31, 2012, $14 million (December 31, 2011 – $12 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2012, $3 million (December 31, 2011 – $4 million) of the balance was not subject to a regulatory return.

8. Sale of Utility Capital Assets

In 2010 Bell Aliant Regional Communications Inc. ("Bell Aliant") exercised its option, under an agreement with Newfoundland Power, to buy back 40% of all joint-use poles owned by Newfoundland Power. In October 2011 Newfoundland Power received proceeds of approximately $46 million from Bell Aliant. In January 2012 the transaction with Bell Aliant closed and a purchase price adjustment of approximately $1 million was paid to Bell Aliant from Newfoundland Power. The purchase price adjustment was based on the results of the pole survey completed in the fourth quarter of 2011. The adjustment was reflected as an increase in utility capital assets in 2012.

9. Other Assets

(in millions)	**2012**	2011
Other asset – Belize Electricity *(Notes 33 and 35)*	**$ 104**	$ 106
Deferred finance charges	**42**	43
Long-term income tax receivable	**13**	–
Subscription Receipt issue costs *(Note 18)*	**13**	–
Long-term accounts receivable (due 2040)	**9**	9
Equity investment in CWLP	**3**	10
Other	**16**	16
	$ 200	$ 184

As a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB and the consequential loss of control over the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's expropriated investment in Belize Electricity is classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing as at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting and, as a result, a foreign exchange loss of approximately $2 million was recognized in earnings in 2012 (2011 – foreign exchange gain of $4.5 million) (Note 24).

As at June 20, 2011, approximately $28 million of unrealized foreign currency translation losses related to the translation into Canadian dollars of the Corporation's previous foreign net investment in Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in Belize Electricity, were reclassified to long-term other assets from accumulated other comprehensive loss and were included in the $104 million balance as at December 31, 2012 (December 31, 2011 – $106 million) (Note 21).

As a result of the findings of an external capital asset review, which was completed in 2011, Maritime Electric filed amendments to its corporate income tax returns in 2012 for the years 2007 through 2010, recognizing a $13 million long-term income tax receivable.

Other Assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable.

10. Utility Capital Assets

2012 *(in millions)*	**Cost**	**Accumulated Depreciation**	**Contributions in Aid of Construction (Net)**	**Net Book Value**
Distribution				
Gas	**$ 2,845**	**$ (746)**	**$ (180)**	**$ 1,919**
Electricity	**5,520**	**(1,694)**	**(593)**	**3,233**
Transmission				
Gas	**1,649**	**(445)**	**(121)**	**1,083**
Electricity	**1,109**	**(300)**	**(3)**	**806**
Generation	**1,360**	**(367)**	**–**	**993**
Other	**1,234**	**(450)**	**(1)**	**783**
Assets under construction	**692**	**–**	**–**	**692**
Land	**114**	**–**	**–**	**114**
	$ 14,523	**$ (4,002)**	**$ (898)**	**$ 9,623**

2011 *(in millions)*	Cost	Accumulated Depreciation	Contributions in Aid of Construction (Net)	Net Book Value
Distribution		*(Note 37)*		
Gas	$ 2,754	$ (684)	$ (179)	$ 1,891
Electricity	5,128	(1,618)	(555)	2,955
Transmission				
Gas	1,615	(416)	(118)	1,081
Electricity	1,072	(276)	(17)	779
Generation	1,339	(339)	–	1,000
Other	1,100	(407)	–	693
Assets under construction	509	–	–	509
Land	110	–	–	110
	$ 13,627	$ (3,740)	$ (869)	$ 9,018

For the years ended December 31, 2012 and 2011

10. Utility Capital Assets (cont'd)

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

As at December 31, 2012, assets under construction associated with larger projects included the Waneta Expansion and AESO transmission-related capital projects at FortisAlberta.

The cost of utility capital assets under capital lease as at December 31, 2012 was $313 million (December 31, 2011 – $312 million) and related accumulated depreciation was $67 million (December 31, 2011 – $61 million).

11. Income Producing Properties

2012

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Buildings	**$ 543**	**$ (85)**	**$ 458**
Equipment	**114**	**(52)**	**62**
Tenant inducements	**31**	**(23)**	**8**
Land	**72**	**–**	**72**
Assets under construction	**26**	**–**	**26**
	$ 786	**$ (160)**	**$ 626**

2011

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Buildings	$ 525	$ (76)	$ 449
Equipment	100	(43)	57
Tenant inducements	29	(21)	8
Land	70	–	70
Assets under construction	10	–	10
	$ 734	$ (140)	$ 594

12. Intangible Assets

2012

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	**$**	**320**	**$**	**(155)**	**$**	**165**
Land, transmission and water rights		**141**		**(21)**		**120**
Franchise fees, customer contracts and other		**15**		**(12)**		**3**
Assets under construction		**37**		**–**		**37**
	$	**513**	**$**	**(188)**	**$**	**325**

2011

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	$	295	$	(125)	$	170
Land, transmission and water rights		134		(17)		117
Franchise fees, customer contracts and other		15		(12)		3
Assets under construction		35		–		35
	$	479	$	(154)	$	325

Included in the cost of land, transmission and water rights as at December 31, 2012 was $66 million (December 31, 2011 – $64 million) not subject to amortization.

As at October 1, 2012, an internal assessment of quantitative and qualitative factors was performed for reporting unit FortisBC Electric. It was determined that the fair value of the indefinite-lived intangible assets at FortisBC Electric was 50% or more likely to be greater than carrying value and, therefore, the assets were not impaired.

As at October 1, 2012, the fair value of reporting units FEI and FEVI was estimated by an independent external consultant and it was concluded by management that the indefinite-lived intangible assets at these reporting units were not impaired.

Amortization expense related to intangible assets was $44 million for 2012 and $38 million for 2011. Amortization is estimated to average approximately $45 million annually for each of the next five years.

As at December 31, 2012, assets under construction primarily related to the Waneta Expansion.

13. Goodwill

(in millions)	**2012**	2011
Balance, beginning of year	**$ 1,565**	$ 1,561
Acquisition of Port Colborne distribution assets *(Note 28)*	**4**	–
Acquisition of TCU *(Note 28)*	**1**	–
Foreign currency translation impacts	**(2)**	4
Balance, end of year	**$ 1,568**	$ 1,565

Goodwill associated with the acquisitions of Caribbean Utilities and the Fortis Turks and Caicos utilities is denominated in US dollars, as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

As at October 1, 2012, an internal assessment of quantitative and qualitative factors was performed for goodwill allocated to reporting units FortisAlberta, FortisBC Electric, Maritime Electric and Cornwall Electric. It was determined that fair value of the reporting units was 50% or more likely to be greater than carrying value and, therefore, goodwill was not impaired.

As at October 1, 2012, fair value of reporting units FEI, FEVI, Caribbean Utilities, Fortis Turks and Caicos and FortisOntario (combined Canadian Niagara Power and Algoma Power), to which goodwill was allocated, was estimated by an independent external consultant and determined to be in excess of carrying value and, therefore, goodwill was not impaired.

14. Accounts Payable and Other Current Liabilities

(in millions)	**2012**	2011
		(Note 37)
Accounts payable – trade	**$ 498**	$ 457
Gas and fuel cost payable	**111**	110
Interest payable	**85**	80
Employee compensation and benefits payable	**81**	79
Dividends payable	**64**	60
Natural gas and fuel purchase option derivatives *(Notes 31 and 32)*	**60**	136
Income taxes payable	**24**	12
OPEB plan liabilities *(Note 27)*	**5**	4
Other	**38**	39
	$ 966	$ 977

The current income taxes payable as at December 31, 2012 reflected the difference between enacted and substantively enacted tax rates applied to the Part VI.1 tax deduction associated with the Corporation's preference share dividends. The Corporation files its annual corporate income tax returns using substantively enacted tax rates for the purpose of determining the Part VI.1 tax deduction, as permitted by CRA. US GAAP, however, requires that the deduction for accounting purposes be based on enacted tax rates. The income tax liability is expected to reverse through the Corporation's earnings when Canadian federal legislation is passed and the proposed corporate income tax rates become enacted or as corporate taxation years become statute-barred. The legislation is expected to be passed in 2013. During 2012 a favourable $2.5 million adjustment to income taxes payable was recognized in earnings associated with statute-barred Part VI.1 taxes (2011 – $1 million).

For the year ended December 31, 2011, the Part VI.1 tax liability was classified in long-term other liabilities (Note 17).

15. Long-Term Debt

(in millions)	Maturity Date	2012	2011
Regulated Utilities			*(Note 37)*
FortisBC Energy Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2011 – 10.71%)	2015 – 2016	**$ 275**	$ 275
Unsecured Debentures –			
5.95% weighted average fixed rate (2011 – 5.95%)	2029 – 2041	**1,620**	1,620
Government loan *(Note 34)*	2013	**4**	20
FortisAlberta			
Unsecured Debentures -			
5.36% weighted average fixed rate (2011 – 5.51%)	2014 – 2052	**1,309**	1,184
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2011 – 9.12%)	2023	**25**	40
Unsecured Debentures –			
5.84% weighted average fixed rate (2011 – 5.84%)	2014 – 2050	**600**	600
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.66% weighted average fixed rate (2011 – 7.66%)	2014 – 2039	**453**	459
Maritime Electric			
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2011 – 7.18%)	2016 – 2061	**167**	167
FortisOntario			
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2011 – 6.11%)	2018 – 2041	**104**	104
Caribbean Utilities			
Unsecured US Senior Loan Notes –			
6.01% weighted average fixed rate (2011 – 6.03%)	2013 – 2031	**187**	207
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. Loan –			
5.05% weighted average fixed and variable rate (2011 – 4.85%)	2014 – 2016	**5**	6
US First Caribbean International Bank loan –			
5.65% fixed rate	2015	**1**	2
US First Caribbean International Bank loan –			
5.00% variable rate	2022	**4**	–
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**1**	2
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
7.11% weighted average fixed rate (2011 – 7.21%)	2013 – 2017	**111**	131
Senior Notes – 7.32% fixed rate	2019	**11**	12
Corporate – Fortis and FHI			
Unsecured:			
Debentures –			
6.14% weighted average fixed rate (2011 – 6.14%)	2014 – 2039	**326**	326
US Senior Notes –			
5.49% weighted average fixed rate (2011 – 5.49%)	2014 – 2040	**547**	559
Long-term classification of credit facility borrowings *(Note 33)*		**150**	74
Total long-term debt *(Note 32)*		**5,900**	5,788
Less: Current installments of long-term debt		**(117)**	(103)
		$ 5,783	$ 5,685

15. Long-Term Debt (cont'd)

The purchase money mortgages of the FortisBC Energy companies are secured equally and rateably by a first fixed and specific mortgage and charge on FEI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $425 million.

As identified in the table above, certain long-term debt instruments issued by FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Properties are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the company to which the long-term debt is associated.

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2012, the Corporation and its subsidiaries, except for the Exploits Partnership, as described below, were in compliance with their debt covenants.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis or Abitibi and was approximately $54 million as at December 31, 2012 (December 31, 2011 – $56 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. See Note 35 for further information on the Exploits Partnership.

Regulated Utilities

The majority of the long-term debt instruments at Regulated Utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

FortisAlberta raised $125 million 40-year 3.98% unsecured debentures, largely in support of its capital expenditure program, in October 2012.

In October 2012 the Series F $15 million secured debentures at FortisBC Electric were repaid.

Corporate – Fortis and FHI

The majority of the unsecured debentures and all of the US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2013	$ 117	$ –	$ 117
2014	541	149	690
2015	134	53	187
2016	291	–	291
2017	81	–	81
Thereafter	3,936	598	4,534

16. Capital Lease and Finance Obligations

Capital Lease Obligations

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA.

The BPPA capital lease obligation bears interest at a composite rate of 4.99%. Included in energy supply costs for 2012 was $25 million (2011 – $24 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 7 *(iii)*).

FortisBC Electric also has a capital lease obligation with respect to the operation of the BTS, under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 8.62%. Included in operating expenses for 2012 was $3 million (2011 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 7 *(iii)*).

The remaining capital lease obligations are held by the FortisBC Energy companies and are associated with various vehicle capital leases having terms that expire in 2013 through 2017.

Finance Obligations

Between 2000 and 2005, FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. Similarly, during 1993, FortisBC Electric entered into an agreement whereby the Trail office building was sold and leased back. The above-noted natural gas distribution assets and the Trail office building are considered to be integral to real estate assets and the transactions were accounted for as financing transactions and the proceeds have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

The finance obligation at FortisBC Electric for the Trail office building matures in 2023 and bears interest at a rate of 8.85% over the remaining term of the lease. Included in operating expenses for 2012 was $1 million (2011 – $1 million) associated with the Trail office building lease, as approved by the BCUC (Note 7 *(iii)*). Under the terms of the agreement, FortisBC Electric has a purchase option in years 20 and 28 of the lease term.

Obligations under the above-noted lease-in lease-out transactions at FEI have maturity dates ranging from 2035 through 2040 bearing interest at rates ranging from 8.49% to 9.52%. Each of the lease-in lease-out arrangements allows for the natural gas distribution assets to be returned to the municipalities after a term of 17 years, being 2017 and 2022. The expected payments required if the assets are returned to the municipalities would equal the carrying values of the obligations on the consolidated balance sheet as at the respective payment dates.

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2013	$ 43	$ 5	$ 48
2014	44	5	49
2015	44	5	49
2016	45	5	50
2017	46	6	52
Thereafter	2,248	97	2,345
	$ 2,470	$ 123	$ 2,593
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(2,158)
Total capital lease and finance obligations			435
Less: Current portion			(7)
			$ 428

17. Other Liabilities

(in millions)	**2012**	2011
		(Note 37)
OPEB plan liabilities *(Note 27)*	**$ 280**	$ 241
Defined benefit pension liabilities *(Note 27)*	**264**	233
Waneta Partnership promissory note *(Note 32)*	**47**	45
DSU and PSU liabilities *(Note 23)*	**10**	8
Customer deposits	**6**	6
Income taxes payable *(Note 14)*	**–**	20
Other liabilities	**15**	11
	$ 622	$ 564

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2012, its discounted net present value was $47 million (December 31, 2011 – $45 million). The promissory note was incurred on the acquisition by the Waneta Partnership, from a company affiliated with CPC/CBT, of certain intangible assets and project design costs associated with the construction of the Waneta Expansion. The promissory note is payable on the fifth anniversary of the commercial operation date of the Waneta Expansion, which is projected to be in spring 2015.

Other liabilities primarily include AROs at FortisBC Electric and funds received in advance of expenditures.

18. Common Shares

Common shares issued during the year were as follows:

	2012		2011	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**188,828**	**$ 3,036**	174,393	$ 2,575
Consumer Share Purchase Plan	**44**	**1**	43	1
Dividend Reinvestment Plan	**1,848**	**60**	1,888	61
Employee Share Purchase Plan	**133**	**4**	–	–
Stock Option Plans	**713**	**20**	790	18
Public offering	**–**	**–**	10,340	331
Conversion of debentures	**–**	**–**	1,374	50
Balance, end of year	**191,566**	**$ 3,121**	188,828	$ 3,036

The 2012 Employee Share Purchase Plan ("2012 ESPP") was approved at the May 4, 2012 Annual General Meeting of the Corporation's shareholders. Under the 2012 ESPP, common shares may be issued from treasury, acquired in the open market or a combination from treasury and the open market, as determined by the Corporation. The first shares issued from treasury under the 2012 ESPP occurred in September 2012.

Subscription Receipts Offering

To finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18.5 million Subscription Receipts at $32.50 each in June 2012 through a bought-deal offering underwritten by a syndicate of underwriters, realizing gross proceeds of approximately $601 million. The gross proceeds from the sale of the Subscription Receipts are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, included in the agreement and plan of merger to acquire CH Energy Group ("Release Conditions"). The Subscription Receipts began trading on the TSX on June 27, 2012 under the symbol "FTS.R".

Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions, and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts to holders of record.

If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition of CH Energy Group is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount (Note 34).

In June 2011 Fortis publicly issued 9.1 million common shares for $33.00 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses. In July 2011 an additional 1.24 million common shares of Fortis were publicly issued for $33.00 per share upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million, or approximately $40 million net of after-tax expenses.

The US$40 million unsecured subordinated convertible debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 per share (US$29.11 per share) in November 2011, as permitted under the debt agreement.

19. Earnings Per Common Share

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 190.0 million for 2012 and 181.6 million for 2011.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2012			2011		
	Earnings to Common Shareholders ***(in millions)***	**Weighted Average Shares** ***(in millions)***	**EPS**	Earnings to Common Shareholders *(in millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**$ 315**	**190.0**	**$ 1.66**	$ 311	181.6	$ 1.71
Effect of potential dilutive securities:						
Stock Options	**–**	**0.8**		–	1.0	
Preference Shares *(Note 20)*	**17**	**10.3**		17	10.1	
Convertible Debentures	**–**	**–**		2	1.2	
	332	**201.1**		330	193.9	
Deduct anti-dilutive impacts:						
Preference Shares	**(7)**	**(3.9)**		(7)	(3.9)	
Diluted EPS	**$ 325**	**197.2**	**$ 1.65**	$ 323	190.0	$ 1.70

20. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2012**		2011	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount** ***(in millions)***	Number of Shares	Amount *(in millions)*
Series C [(1)]	$ 1.3625	**5,000,000**	**$ 123**	5,000,000	$ 123
Series E [(1)]	$ 1.2250	**7,993,500**	**197**	7,993,500	197
Series F [(1)]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [(2)]	$ 1.3125	**9,200,000**	**225**	9,200,000	225
Series H [(2)]	$ 1.0625	**10,000,000**	**245**	10,000,000	245
Series J [(1)]	$ 1.1875	**8,000,000**	**196**	–	–
		45,193,500	**$ 1,108**	37,193,500	$ 912

[(1)] Cumulative Redeemable First Preference Shares
[(2)] Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares

In November 2012 the Corporation issued 8 million First Preference Shares, Series J at $25.00 per share for net after-tax proceeds of approximately $196 million.

Holders of the First Preference Shares, Series C, E, F and J are each entitled to receive a fixed cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

20. Preferred Shares (cont'd)

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series C and Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series C and Series E for cash or arrange for the sale of those shares to other purchasers.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each preference share may be converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G and Series H are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $1.3125 and $1.0625 per share per annum, respectively, for each year up to but excluding September 1, 2013 and June 1, 2015, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2013 and June 1, 2015 and each five-year period thereafter, the holders of First Preference Shares, Series G and Series H, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G and Series H, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13% and 1.45%, respectively.

On each Series H Conversion Date, 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. The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

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

21. Accumulated Other Comprehensive Loss

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive loss by category is provided as follows:

	2012		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation losses on net investments in foreign operations	**$ (103)**	**$ (12)**	**$ (115)**
Gains on hedges of net investments in foreign operations	**33**	**12**	**45**
Income tax expense	**(4)**	**(2)**	**(6)**
	(74)	**(2)**	**(76)**
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	**(4)**	**1**	**(3)**
Income tax recovery	**1**	**–**	**1**
	(3)	**1**	**(2)**
Unrealized employee future benefits losses: *(Note 27)*			
Unamortized past service costs	**(1)**	**–**	**(1)**
Unamortized net actuarial losses	**(19)**	**–**	**(19)**
Income tax recovery	**2**	**–**	**2**
	(18)	**–**	**(18)**
Accumulated other comprehensive loss	**$ (95)**	**$ (1)**	**$ (96)**

(in millions)	2011 Opening balance January 1	2011 Net change	2011 Ending balance December 31
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	$ (140)	$ 37	$ (103)
Gains (losses) on hedges of net investments in foreign operations	56	(23)	33
Income tax (expense) recovery	(8)	4	(4)
	(92)	18	(74)
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(6)	2	(4)
Income tax recovery (expense)	2	(1)	1
	(4)	1	(3)
Unrealized employee future benefits losses: *(Note 27)*			
Unamortized past service costs	(1)	–	(1)
Unamortized net actuarial losses	(12)	(7)	(19)
Income tax recovery	1	1	2
	(12)	(6)	(18)
Accumulated other comprehensive loss	$ (108)	$ 13	$ (95)

For the year ended December 31, 2011, the net change in accumulated other comprehensive loss included the reclassification of $28 million of unrealized foreign currency translation losses related to the translation into Canadian dollars of the Corporation's previous foreign net investment in Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in Belize Electricity, to long-term other assets from accumulated other comprehensive loss. The reclassifications were the result of the expropriation of Belize Electricity on June 20, 2011 (Notes 9, 33 and 35).

22. Non-Controlling Interests

(in millions)	**2012**	2011
Waneta Partnership	**$ 220**	$ 128
Caribbean Utilities	**71**	73
Mount Hayes Limited Partnership *(Note 34)*	**12**	–
Preference shares of Newfoundland Power	**7**	7
	$ 310	$ 208

23. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2012, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to replace the former Executive Stock Option Plan ("ESOP") and the Directors' Stock Option Plan. All of the outstanding options under the former ESOP were exercised during 2011. The 2006 Plan was approved at the May 2, 2006 Annual General Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting. The 2012 Plan will ultimately replace the 2002 Plan and the 2006 Plan. The 2002 Plan and 2006 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 Plan and 2006 Plan and all new options granted after 2011 are being made under the 2012 Plan.

23. Stock-Based Compensation Plans (cont'd)

Stock Options (cont'd)

Options granted under the 2006 Plan are exercisable for a period not to exceed seven 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 2006 Plan.

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 following options were granted in 2012 and 2011.

	2012	2011
Options granted *(#)* [(1)]	**789,220**	828,512
Exercise price *($)* [(2)]	**34.27**	32.95
Grant date fair value *($)*	**4.21**	4.57

(1) Options were granted in May 2012 and March 2011
(2) Five-day volume weighted average trading price immediately preceding the date of grant

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

	2012	2011
Dividend yield *(%)* [(1)]	**3.67**	3.68
Expected volatility *(%)* [(2)]	**22.2**	23.1
Risk-free interest rate *(%)* [(3)]	**1.50**	2.00
Weighted average expected life *(years)* [(4)]	**5.3**	4.5

(1) Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options
(2) Based on historical experience over a period equal to the weighted average expected life of the options
(3) Government of Canada benchmark bond yield in effect at the time of the grant that covers the weighted average expected life of the options
(4) Based on historical experience

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to the stock options for 2012.

	Total Options		**Nonvested Options** [(1)]	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Grant Date Fair Value**
Options outstanding, January 1, 2012	**4,709,229**	**$ 25.81**	**2,136,454**	**$ 4.43**
Granted	**789,220**	**$ 34.27**	**789,220**	**$ 4.21**
Exercised	**(712,858)**	**$ 23.81**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(889,442)**	**$ 4.43**
Cancelled/Forfeited	**(42,926)**	**$ 26.14**	**(39,180)**	**$ 4.41**
Options outstanding, December 31, 2012	**4,742,665**	**$ 27.49**	**1,997,052**	**$ 4.34**
Options vested, December 31, 2012 [(2)]	**2,745,613**	**$ 24.79**		

(1) As at December 31, 2012, there was $9 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of three years.
(2) As at December 31, 2012, the weighted average remaining term of vested options was three years with an aggregate intrinsic value of $26 million.

Notes to Consolidated Financial Statements

The following table summarizes additional 2012 and 2011 stock option information.

(in millions)	**2012**	2011
Stock option expense recognized	**$ 4**	$ 4
Stock options exercised:		
Cash received for exercise price	**17**	15
Intrinsic value realized by employees	**7**	11
Fair value of options that vested	**4**	4

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

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.

Number of DSUs	**2012**	2011
DSUs outstanding, beginning of year	**147,629**	146,951
Granted	**21,417**	27,070
Granted – notional dividends reinvested	**6,280**	5,429
DSUs paid out	**–**	(31,821)
DSUs outstanding, end of year	**175,326**	147,629

For the year ended December 31, 2012, expense of $1 million (2011 – $1 million) was recognized in earnings with respect to the DSU Plan.

No DSUs were paid out in 2012. During 2011 31,821 DSUs were paid out, subsequent to the death of a Board member, at a price of $33.06 per DSU, for a total of approximately $1 million.

As at December 31, 2012, the total liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $34.22, for a total of $6 million (December 31, 2011 – $5 million), and is included in long-term other liabilities (Note 17).

PSU Plan

The Corporation's PSU Plan is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of PSUs	**2012**	2011
PSUs outstanding, beginning of year	**154,658**	141,408
Granted	**62,000**	45,000
Granted – notional dividends reinvested	**6,217**	5,329
PSUs paid out	**(44,863)**	(37,079)
PSUs outstanding, end of year	**178,012**	154,658

In March 2012 44,863 PSUs were paid out to the President and CEO of the Corporation at $32.40 per PSU, for a total of approximately $1.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2009 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors.

23. Stock-Based Compensation Plans (cont'd)

PSU Plan (cont'd)

In May 2012 62,000 PSUs were granted to the President and CEO of the Corporation. The maturation period of the May 2012 PSU grant is three years, at which time a cash payment may be made to the President and CEO after evaluation by the Human Resources Committee of the Board of Directors of the achievement of payment requirements.

For the year ended December 31, 2012, expense of $2 million (2011 – $2 million) was recognized in earnings with respect to the PSU Plan.

As at December 31, 2012, the total liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $34.22, for a total of $4 million (December 31, 2011 – $3 million), and is included in long-term other liabilities (Note 17).

24. Other Income, Net

(in millions)	**2012**	2011
Equity component of AFUDC *(Note 3)*	**$ 7**	$ 13
Interest income	**5**	4
Other income, net of expenses	**1**	1
Acquisition-related expenses	**(9)**	–
Net foreign exchange gain	**–**	3
Merger termination fee	**–**	17
	$ 4	$ 38

A foreign exchange loss of approximately $2 million was recognized in 2012 related to the translation into Canadian dollars of the Corporation's US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity (Notes 9, 33 and 35). The foreign exchange loss was offset by foreign exchange gains related to foreign currency transactions at Caribbean Utilities.

A $4.5 million foreign exchange gain was recognized in 2011 related to the translation into Canadian dollars of the above-noted long-term other asset (Note 9), which was partially offset by an approximate $3.5 million ($3 million after-tax) foreign exchange loss on the translation into Canadian dollars of the Corporation's previously hedged US dollar-denominated long-term debt. The net foreign exchange gain in 2011 also included amounts related to foreign currency transactions at Caribbean Utilities.

The acquisition-related expenses are associated with the pending acquisition of CH Energy Group (Notes 1 and 34).

The termination fee was paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation.

25. Finance Charges

(in millions)	**2012**	2011
Interest – Long-term debt and capital lease obligations	**$ 377**	$ 372
– Short-term borrowings	**7**	10
Debt component of AFUDC *(Note 3)*	**(18)**	(19)
	$ 366	$ 363

26. Income Taxes

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. Deferred income tax assets and liabilities comprised the following:

(in millions)	**2012**	2011
Deferred income tax liability (asset)		
Utility capital assets	**$ 675**	$ 605
Income producing properties	**30**	28
Intangible assets	**47**	33
Regulatory assets	**161**	137
Other assets and liabilities (net)	**(89)**	(63)
Regulatory liabilities	**(121)**	(99)
Loss carryforwards	**(17)**	(19)
Unrecognized tax benefits	**16**	22
Unrealized foreign currency translation gains on long-term debt	**8**	7
Share issue and debt financing costs	**2**	1
Net deferred income tax liability	**$ 712**	$ 652
Current deferred income tax asset	**$ (16)**	$ (24)
Current deferred income tax liability	**10**	8
Long-term deferred income tax asset	**–**	(8)
Long-term deferred income tax liability	**718**	676
Net deferred income tax liability	**$ 712**	$ 652

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2012 and 2011.

(in millions)	**2012**	2011
Total unrecognized tax benefits, beginning of year	**$ 22**	$ 22
Additions related to the current year	**1**	1
Adjustments related to prior years	**(3)**	-
Reductions related to the lapse of applicable statutes of limitations	**(4)**	(1)
Total unrecognized tax benefits, end of year	**$ 16**	$ 22

If the total amount of unrecognized tax benefits as at December 31, 2012 of $16 million (December 31, 2011 – $22 million) were ultimately realized, income tax expense for 2012 would have decreased by approximately $15 million (2011 – $19 million). The Corporation has unrecognized tax benefits related to corporate transactions of a prior year that could increase earnings by approximately $1 million in 2013 if the transactions become statute-barred. The Corporation does not expect that the total unrecognized tax benefits will significantly change within the next 12 months.

Interest and penalties recognized as income tax expense related to liabilities for unrecognized tax benefits were $1 million for 2012 (2011 – $1 million). Interest and penalties accrued as accounts payable and accrued liabilities related to liabilities for unrecognized tax benefits as at December 31, 2012 were $8 million (December 31, 2011 – $9 million). Taxation years 2007 and prior are no longer subject to examination in Canada, other than transactions with related non-residents which are no longer subject to examination in Canada for taxation years 2004 and prior.

26. Income Taxes (cont'd)

The components of the provision for income taxes were as follows:

(in millions)	**2012**	2011
Canadian		
Current taxes	**$ 46**	$ 75
Deferred income taxes	**78**	59
Less regulatory adjustments	**(61)**	(57)
	17	2
Total Canadian	**$ 63**	$ 77
Foreign		
Current taxes	**$ (2)**	$ 5
Deferred income taxes	**–**	2
Total Foreign	**$ (2)**	$ 7
Income taxes	**$ 61**	$ 84

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 taxes to consolidated effective taxes.

(in millions, except as noted)	**2012**	2011
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	30.5%
Statutory income tax rate applied to earnings before income taxes	**$ 125**	$ 137
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(13)**	(12)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(13)**	(13)
Items capitalized for accounting purposes but expensed for income tax purposes	**(44)**	(53)
Difference between capital cost allowance and amounts claimed for accounting purposes	**1**	13
Non-deductible expenses	**4**	9
Part VI.1 tax – difference between enacted and substantially enacted income tax rates and the effect of statute-barred reversals	**4**	4
Difference between employee future benefits paid and amounts expensed for accounting purposes	**1**	(4)
Other	**(4)**	3
Income taxes	**$ 61**	$ 84
Effective tax rate	**14.1%**	18.7%

As at December 31, 2012, the Corporation had approximately $73 million (December 31, 2011 – $86 million) in non-capital and capital loss carryforwards, of which $13 million (December 31, 2011 – $13 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2013 and 2032.

27. 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 RRSPs for employees. The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and Algoma Power also offer OPEB plans for qualifying employees.

For the defined benefit pension plan arrangements, the projected pension benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2009 and 2010 for the FortisBC Energy companies (plans covering non-unionized employees); as of December 31, 2010 for the FortisBC Energy companies (plan covering unionized employees), FortisAlberta and FortisBC Electric; as of December 31, 2011 for the Corporation, Newfoundland Power and FortisOntario; as of July 1, 2012 for Algoma Power; and as of December 31, 2012 for Caribbean Utilities. The next required valuations for funding purposes will be, at the latest, three years from the date of the most recent actuarial valuation of each plan, as noted above.

The Corporation's investment policy is to ensure that the pension assets, together with expected contributions, are invested in a prudent and cost-effective manner so as to optimally meet the liabilities of the plans for its members. The investment objective of the pension plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and pension expense for financial statement purposes.

The Corporation's consolidated defined benefit pension plan weighted average asset allocation was as follows:

Plan assets as at December 31 *(%)*	**2012 Target Allocation**	**2012**	2011
Equities	**47**	**50**	48
Fixed income	**44**	**44**	45
Real estate	**6**	**6**	7
Cash and other	**3**	**–**	–
	100	**100**	100

The fair value measurements of pension plan assets by fair value hierarchy, as defined in Note 32, were as follows:

Fair value of plan assets as at December 31, 2012

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 235**	**$ 195**	**$ –**	**$ 430**
Fixed income	**–**	**382**	**–**	**382**
Real estate	**–**	**–**	**53**	**53**
Cash and other	**2**	**1**	**–**	**3**
	$ 237	**$ 578**	**$ 53**	**$ 868**

Fair value of plan assets as at December 31, 2011

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 212	$ 162	$ –	$ 374
Fixed income	27	325	–	352
Real estate	2	14	41	57
Cash and other	1	1	–	2
	$ 242	$ 502	$ 41	$ 785

27. Employee Future Benefits (cont'd)

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2012 and 2011.

(in millions)	**2012**	2011
Balance, beginning of year	**$ 41**	$ 33
Actual return on plan assets held at end of year	**5**	4
Purchases, sales and settlements	**7**	4
Balance, end of year	**$ 53**	$ 41

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded status.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2012**	2011	**2012**	2011
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 1,018**	$ 879	**$ 245**	$ 203
Service costs	**27**	20	**6**	5
Employee contributions	**14**	14	**–**	–
Interest costs	**47**	47	**12**	11
Benefits paid	**(43)**	(38)	**(6)**	(6)
Actuarial losses	**69**	96	**27**	31
Past services costs/plan amendments	**–**	–	**1**	1
Balance, end of year [(2)]	**$ 1,132**	$ 1,018	**$ 285**	$ 245
Change in value of plan assets				
Balance, beginning of year	**$ 785**	$ 732	**$ –**	$ –
Actual return on plan assets	**67**	44	**–**	–
Benefits paid	**(43)**	(38)	**(6)**	(6)
Employee contributions	**14**	14	**–**	–
Employer contributions	**45**	34	**6**	6
Actual plan expenses	**–**	(1)	**–**	–
Balance, end of year	**$ 868**	$ 785	**$ –**	$ –
Funded status	**$ (264)**	$ (233)	**$ (285)**	$ (245)

(1) Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans
(2) The accumulated benefit obligation for defined benefit pension plans, which includes no assumption about future salary levels, was $999 million as at December 31, 2012 (December 31, 2011 – $900 million).

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2012**	2011	**2012**	2011
Liabilities				
Defined benefit pension liabilities:				
Long-term other liabilities *(Note 17)*	**$ 264**	$ 233	**$ –**	$ –
OPEB plan liabilities:				
Current *(Note 14)*	**–**	–	**5**	4
Long-term other liabilities *(Note 17)*	**–**	–	**280**	241
Net Liabilities	**$ 264**	$ 233	**$ 285**	$ 245

As at December 31, 2012, all of the defined benefit pension plans had projected benefit obligations in excess of plan assets.

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows:

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2012**	2011	**2012**	2011
Components of net benefit cost				
Service costs	**$ 27**	$ 20	**$ 6**	$ 5
Interest costs	**47**	47	**12**	11
Expected return on plan assets	**(50)**	(47)	**–**	–
Amortization of actuarial losses	**26**	20	**5**	3
Amortization of past service costs/plan amendments (credits)	**–**	1	**(3)**	(4)
Amortization of transitional obligation	**–**	–	**1**	2
Regulatory adjustments	**(10)**	(7)	**1**	4
Net benefit cost	**$ 40**	$ 34	**$ 22**	$ 21

The following tables provide the components of accumulated other comprehensive loss and regulatory assets, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2012 and 2011 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2012**	2011	**2012**	2011
Unamortized net actuarial losses	**$ 15**	$ 15	**$ 4**	$ 4
Unamortized past service costs	**–**	–	**1**	1
Income tax recovery	**(2)**	(2)	**–**	–
Accumulated other comprehensive loss *(Note 21)*	**$ 13**	$ 13	**$ 5**	$ 5
Net actuarial losses	**$ 311**	$ 285	**$ 110**	$ 88
Past service credits	**(1)**	(1)	**(23)**	(27)
Transitional obligation	**–**	–	**1**	2
Amount deferred due to actions of regulators	**40**	37	**60**	59
Regulatory assets *(Note 7 (ii))*	**$ 350**	$ 321	**$ 148**	$ 122

The following tables provide the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2012**	2011	**2012**	2011
Current year net actuarial losses	**$ 2**	$ 6	**$ –**	$ 1
Amortization of actuarial losses	**(2)**	–	**–**	–
Income tax recovery	**–**	(1)	**–**	–
Total recognized in comprehensive income	**$ –**	$ 5	**$ –**	$ 1
Current year net actuarial losses	**$ 50**	$ 91	**$ 27**	$ 31
Amortization of actuarial losses	**(24)**	(18)	**(5)**	(3)
Amortization of past service credits	**–**	–	**4**	4
Amortization of transitional obligation	**–**	–	**(1)**	(1)
Regulatory adjustments	**3**	7	**1**	(5)
Total recognized in regulatory assets	**$ 29**	$ 80	**$ 26**	$ 26

27. Employee Future Benefits (cont'd)

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive loss into net benefit cost in 2013 related to defined benefit pension plans.

Net actuarial losses of $27 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2013 related to defined benefit pension plans. Net actuarial losses of $6 million, past service credits of $3 million and regulatory adjustments of $4 million are expected to be amortized from regulatory assets into net benefit cost in 2013 related to OPEB plans.

Significant weighted average assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
	2012	2011	**2012**	2011
Discount rate during the year *(%)*	**4.62**	5.44	**4.65**	5.43
Discount rate as at December 31 *(%)*	**4.14**	4.62	**4.20**	4.64
Expected long-term rate of return on plan assets *(%)* [(1)]	**6.41**	6.72	**–**	–
Rate of compensation increase *(%)*	**3.39**	3.39	**3.71**	3.68
Health care cost trend increase as at December 31 *(%)* [(2)]	**–**	–	**4.62**	4.65

(1) Developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(2) The projected 2013 weighted average health care cost trend rate is 7.72% for OPEBs and is assumed to decrease over the next 10 years by 2022 to the weighted average ultimate health care cost trend rate of 4.62% and remain at that level thereafter.

For 2012 the effects of changing the health care cost trend rate by 1% were as follows:

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in benefit obligation	**$ 33**	**$ (27)**
Increase (decrease) in service and interest costs	**2**	**(2)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	**Defined Benefit Pension Payments** *(in millions)*	**OPEB Payments** *(in millions)*
2013	$ 41	$ 8
2014	43	9
2015	44	10
2016	48	11
2017	51	12
2018 – 2022	293	70

Refer to Note 34 for expected defined benefit pension funding contributions.

During 2012 the Corporation expensed $14 million (2011 – $13 million) related to defined contribution pension plans.

28. Business Acquisitions

2012

OTHER CANADIAN REGULATED ELECTRIC UTILITIES – PORT COLBORNE HYDRO ASSETS

In April 2012 FortisOntario exercised its option, under the terms of a 10-year operating lease agreement with the City of Port Colborne that commenced in April 2002, to purchase the remaining assets of Port Colborne Hydro for approximately $7 million. Under the lease arrangement with the City of Port Colborne, and now through ownership of the previously leased assets, FortisOntario operates and maintains the City of Port Colborne's electricity distribution system for provision of electricity service to the residents of Port Colborne. Throughout the 10-year lease term, FortisOntario incurred approximately $17 million in capital expenditures in Port Colborne Hydro's electricity distribution system. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, which constitute the entire electricity distribution system in Port Colborne. The purchase was approved by the OEB.

FortisOntario is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair market value approximates book value and no adjustments were recorded for the assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, $3 million of the purchase price was allocated to utility capital assets and $4 million was recognized as goodwill in the purchase price allocation. The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing in April 2012.

REGULATED ELECTRIC UTILITIES CARIBBEAN – TCU

In August 2012 FortisTCI acquired TCU for an aggregate cash purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million). TCU is a regulated electric utility operating pursuant to a 50-year licence expiring in 2036. The utility serves more than 2,000 residential and commercial customers on Grand Turk and Salt Cay with a diesel-fired generating capacity of 9 MW. TCU is regulated under COS and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair market value approximates book value and no adjustments were recorded for the net assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, approximately $9 million of the purchase price was allocated to utility capital assets, $3 million to current net assets, $5 million to long-term debt and $1 million was recognized as goodwill in the purchase price allocation. The acquisition has been accounted for using the acquisition method, whereby financial results of TCU have been consolidated in the financial statements of Fortis commencing in August 2012.

NON-REGULATED – STATIONPARK ALL SUITE HOTEL

In October 2012 Fortis Properties acquired the StationPark All Suite Hotel for an aggregate cash purchase price of $13 million, inclusive of debt assumed of $6 million. Accordingly, $13 million of the purchase price was allocated to income producing properties and $6 million was allocated to long-term debt. The acquisition has been accounted for using the acquisition method, whereby financial results of the hotel have been consolidated in the financial statements of Fortis commencing in October 2012.

2011

NON-REGULATED – HILTON SUITES WINNIPEG AIRPORT

In October 2011 Fortis Properties purchased the Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million, which was allocated to income producing properties. The acquisition has been accounted for using the acquisition method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing in October 2011.

29. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2012 *($ millions)*	**FortisBC Energy Companies – Canadian**	Fortis Alberta	FortisBC Electric	NF Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,426**	448	306	581	353	**1,688**	**273**	**31**	**242**	**24**	**(30)**	**3,654**
Energy supply costs	**669**	–	76	380	227	**683**	**170**	**1**	**–**	**–**	**(1)**	**1,522**
Operating expenses	**287**	158	85	74	48	**365**	**34**	**9**	**166**	**14**	**(7)**	**868**
Depreciation and amortization	**160**	133	48	44	26	**251**	**32**	**4**	**21**	**2**	**–**	**470**
Operating income	**310**	157	97	83	52	**389**	**37**	**17**	**55**	**8**	**(22)**	**794**
Other income (expenses), net	**2**	4	1	2	–	**7**	**2**	**3**	**–**	**(9)**	**(1)**	**4**
Finance charges	**142**	65	39	36	21	**161**	**13**	**2**	**24**	**47**	**(23)**	**366**
Income tax expense (recovery)	**31**	–	9	11	7	**27**	**–**	**1**	**9**	**(7)**	**–**	**61**
Net earnings (loss)	**139**	96	50	38	24	**208**	**26**	**17**	**22**	**(41)**	**–**	**371**
Non-controlling interests	**1**	–	–	1	–	**1**	**7**	**–**	**–**	**–**	**–**	**9**
Preference share dividends	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**47**	**–**	**47**
Net earnings (loss) attributable to common equity shareholders	**138**	96	50	37	24	**207**	**19**	**17**	**22**	**(88)**	**–**	**315**
Goodwill	**913**	227	221	–	67	**515**	**140**	**–**	**–**	**–**	**–**	**1,568**
Identifiable assets	**4,595**	2,776	1,705	1,389	720	**6,590**	**740**	**737**	**655**	**511**	**(446)**	**13,382**
Total assets	**5,508**	3,003	1,926	1,389	787	**7,105**	**880**	**737**	**655**	**511**	**(446)**	**14,950**
Gross capital expenditures [(1)]	**206**	442	69	86	48	**645**	**48**	**196**	**35**	**–**	**–**	**1,130**
Year Ended December 31, 2011 *($ millions)*												
Revenue	1,566	408	296	573	339	1,616	305	34	231	23	(37)	3,738
Energy supply costs	854	–	72	369	218	659	192	1	–	–	(9)	1,697
Operating expenses	293	144	83	75	48	350	40	8	156	9	(6)	850
Depreciation and amortization	113	134	45	42	24	245	33	4	19	2	–	416
Operating income	306	130	96	87	49	362	40	21	56	12	(22)	775
Other income, net	8	5	1	–	–	6	3	1	–	21	(1)	38
Finance charges	137	60	39	36	20	155	14	2	24	54	(23)	363
Income tax expense (recovery)	40	1	10	18	9	38	1	2	9	(6)	–	84
Net earnings (loss)	137	74	48	33	20	175	28	18	23	(15)	–	366
Non-controlling interests	–	–	–	1	–	1	8	–	–	–	–	9
Preference share dividends	–	–	–	–	–	–	–	–	–	46	–	46
Net earnings (loss) attributable to common equity shareholders	137	74	48	32	20	174	20	18	23	(61)	–	311
Goodwill	913	227	221	–	63	511	141	–	–	–	–	1,565
Identifiable assets	4,579	2,483	1,665	1,299	670	6,117	719	546	610	469	(391)	12,649
Total assets	5,492	2,710	1,886	1,299	733	6,628	860	546	610	469	(391)	14,214
Gross capital expenditures [(1)]	250	416	102	81	47	646	71	174	30	–	–	1,171

[(1)] Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected on the consolidated statements of cash flows

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011; (ii) electricity sales from Newfoundland Power to Fortis Properties; (iii) sales of energy from Fortis Generation to FortisOntario; and (iv) finance charges on related party borrowings. The significant related party inter-segment transactions during the years ended December 31 were as follows:

Significant Related Party Inter-Segment Transactions

(in millions)	**2012**	2011
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ –**	$ 7
Sales from Newfoundland Power to Fortis Properties	**5**	5
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Inter-segment finance charges on lending from:		
Fortis Generation to Other Canadian Electric Utilities	**2**	1
Corporate to Other Canadian Electric Utilities	**–**	2
Corporate to Regulated Electric Utilities – Caribbean	**4**	4
Corporate to Fortis Generation	**1**	3
Corporate to Fortis Properties	**16**	13

The significant related party inter-segment asset balances as at December 31 were as follows:

(in millions)	**2012**	2011
Inter-segment borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Regulated Electric Utilities – Caribbean	**85**	76
Corporate to Fortis Generation	**9**	23
Corporate to Fortis Properties	**307**	249
Other inter-segment assets	**25**	23
Total inter-segment eliminations	**$ 446**	$ 391

30. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2012**	2011
Cash paid for:		
Interest	**$ 374**	$ 359
Income taxes	**83**	67
Change in non-cash operating working capital:		
Accounts receivable	**$ 49**	$ 6
Prepaid expenses	**1**	(2)
Regulatory assets – current portion	**(32)**	(4)
Inventories	**3**	30
Accounts payable and other current liabilities	**36**	60
Regulatory liabilities – current portion	**21**	9
	$ 78	$ 99
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 58**	$ 59
Additions to utility capital assets, income producing properties and intangible assets included in current liabilities	**88**	102
Contributions in aid of construction included in current assets	**17**	9
Conversion of convertible debentures into common shares	**–**	50
Exercise of stock options into common shares	**3**	3

31. Derivative Instruments and Hedging Activities

As discussed in Note 3, the Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at December 31, 2012, the Corporation's derivative instruments consisted of fuel option contracts, natural gas swap and option contracts, and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities and the remaining derivative instruments are held by the FortisBC Energy companies.

Volume of Derivative Activity

As at December 31, 2012, the following notional volumes related to fuel option contracts and natural gas derivatives that are expected to be settled are outlined below.

	2013	2014
Fuel option contracts *(millions of imperial gallons)*	14	–
Gas swaps and options *(petajoules)*	21	6
Gas purchase contract premiums *(petajoules)*	70	12

Presentation of Derivative Instruments in the Consolidated Financial Statements

In the Corporation's consolidated balance sheet, derivative instruments are presented on a net basis by counterparty, where the right of offset exists. The net balances include outstanding cash collateral associated with derivative positions.

The Corporation's outstanding derivative balances as at December 31 were as follows:

(in millions)	**2012**	2011
Gross derivatives balance [1]	**$ 60**	$ 136
Netting [2]	**–**	–
Cash collateral	**–**	–
Total derivatives balance [3]	**$ 60**	$ 136

[1] Refer to Note 32 for a discussion of the valuation techniques used to calculate the fair value of the derivative instruments.
[2] Positions, by counterparty, are netted where the intent and legal right to offset exists.
[3] Unrealized losses of $60 million on commodity risk-related derivative instruments were recognized in current regulatory assets as at December 31, 2012 (December 31, 2011 – $136 million), which would otherwise be recognized on the consolidated statement of comprehensive income and in accumulated other comprehensive loss. These amounts exclude the impact of cash collateral postings.

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

The majority of the FortisBC Energy companies' commodity risk-related derivative instruments contain collateral posting provisions tied to FEI's credit rating. A downgrade of FEI below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under FEI's gas purchase and swap and option contracts. All of the existing natural gas derivative contracts are in liability positions and might be subject to margin calls and other cash requirements if FEI was downgraded below investment grade.

32. Fair Value Measurements

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

Notes to Consolidated Financial Statements

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

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

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

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

Asset (Liability)	**2012**		2011	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Other asset – Belize Electricity [(1)]	**$ 104**	**$ n/a [(2)]**	$ 106	$ n/a [(2)]
Long-term debt, including current portion [(3)]	**(5,900)**	**(7,338)**	(5,788)	(7,197)
Waneta Partnership promissory note [(4)]	**(47)**	**(51)**	(45)	(49)
Fuel option contracts [(5)]	**(1)**	**(1)**	(1)	(1)
Natural gas derivatives: [(5)]				
Gas swaps and options	**(51)**	**(51)**	(135)	(135)
Gas purchase contract premiums	**(8)**	**(8)**	–	–

(1) Included in long-term other assets on the consolidated balance sheet (Note 9)
(2) The Corporation's expropriated investment in Belize Electricity is recognized at book value, including foreign exchange impacts, in long-term other assets on the consolidated balance sheet. The actual amount of compensation that the GOB may pay to Fortis is indeterminable at this time (Notes 33 and 35).
(3) The Corporation's $200 million unsecured debentures due 2039 and consolidated credit facilities classified as long-term debt are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.
(4) Included in long-term other liabilities on the consolidated balance sheet (Note 17)
(5) The fair values of the derivatives were recorded in accounts payable and other current liabilities as at December 31, 2012 and 2011 (Note 14).

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, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) by obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and was calculated using published market prices for heating oil or similar commodities. The fuel option contracts mature on or before October 1, 2013. Approximately 70% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies 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 commodity cost of natural gas.

The fair values of the fuel option contracts and the natural gas derivatives were estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. As at December 31, 2012, none of the fuel option contracts or natural gas derivatives were designated as hedges of fuel purchases or natural gas supply contracts. However, any gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators.

33. 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 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 December 31, 2012, its gross credit risk exposure was approximately $114 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to less than $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with reasonable credit-quality institutions in accordance with established credit-approval practices. The FortisBC Energy companies do not expect any counterparties to fail to meet their obligations. The counterparties with which the FortisBC Energy companies have significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

The following table summarizes the FortisBC Energy companies' net credit risk exposure to its counterparties, as well as credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as it relates to its natural gas swaps and options, as at December 31, 2012 and 2011.

(in millions, except for number of counterparties)	**2012**	2011
Gross credit exposure before credit collateral [(1)]	**$ 51**	$ 136
Credit collateral	**–**	–
Net credit exposure [(2)]	**$ 51**	$ 136
Number of counterparties > 10%	**4**	4
Net exposure to counterparties > 10%	**$ 45**	$ 104

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported do not include adjustments for time value or liquidity.
(2) Net credit exposure is the gross credit exposure collateral minus credit collateral (cash deposits and letters of credit).

The Corporation is exposed to credit risk associated with the amount and timing of fair value compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. As at December 31, 2012, the Corporation had a long-term other asset of $104 million (December 31, 2011 – $106 million), including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 9, 32 and 35).

Additionally, as at December 31, 2012, Belize Electricity owed BECOL approximately US$8 million for energy purchases, of which US$7 million was overdue. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Liquidity Risk

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

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

The Corporation's committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $275 million. 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.

As at December 31, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.5 billion, of which approximately $2.1 billion was unused, including $946 million unused under the Corporation's $1 billion committed corporate credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.3 billion of the total credit facilities are committed facilities with maturities ranging from 2013 through 2017.

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

(in millions)	Regulated Utilities	Fortis Properties	Corporate and Other	**Total as at December 31, 2012**	Total as at December 31, 2011
Total credit facilities	$ 1,402	$ 13	$ 1,045	**$ 2,460**	$ 2,248
Credit facilities utilized:					
Short-term borrowings [1]	(136)	–	–	**(136)**	(159)
Long-term debt *(Note 15)* [2]	(97)	–	(53)	**(150)**	(74)
Letters of credit outstanding	(66)	–	(1)	**(67)**	(66)
Credit facilities unused	$ 1,103	$ 13	$ 991	**$ 2,107**	$ 1,949

[1] The weighted average interest rate on short-term borrowings was 1.9% as at December 31, 2012 (December 31, 2011 – 1.9%)

[2] As at December 31, 2012, credit facility borrowings classified as long-term debt included $24 million (December 31, 2011 – $16 million) that was included in current installments of long-term debt on the consolidated balance sheet. The weighted average interest rate on credit facility borrowings classified as long-term debt was 2.1% as at December 31, 2012 (December 31, 2011 – 2.2%).

As at December 31, 2012 and 2011, 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.

Regulated Utilities

FEI has a $500 million unsecured committed revolving credit facility, maturing August 2014. FEVI has a $200 million unsecured committed revolving credit facility, maturing December 2013. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes. FEVI also had a $20 million unsecured committed non-revolving credit facility, which matured in January 2013.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing August 2016, that is utilized to finance capital expenditures and for general corporate purposes. FortisAlberta also has a $10 million swingline loan within its committed credit facility.

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

33. Financial Risk Management (cont'd)

Liquidity Risk (cont'd)

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2013 and the remaining $100 million matures May 2015. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2017, and a $20 million demand credit facility.

Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing February 2014, and a $5 million unsecured demand credit facility.

FortisOntario has a $30 million unsecured revolving credit facility, maturing June 2013.

Caribbean Utilities has unsecured credit facilities of approximately US$47 million ($47 million), comprised of a capital expenditure demand loan facility of US$31 million ($31 million), letters of credit of US$1 million ($1 million), a US$7.5 million ($7.5 million) demand operating line of credit and a US$7.5 million ($7.5 million) catastrophe standby loan.

Fortis Turks and Caicos has unsecured demand credit facilities of US$21 million ($21 million), comprised of a revolving operating credit facility of US$5 million ($5 million), a capital expenditure line of credit of US$7 million ($7 million) and a US$9 million ($9 million) emergency standby loan.

Fortis Properties
Fortis Properties has a $13 million secured revolving demand credit facility that can be utilized for general corporate purposes.

Corporate and Other
Fortis has a $1 billion unsecured committed revolving credit facility, maturing July 2015, that is available for general corporate purposes and interim financing of acquisitions.

FHI has a $30 million unsecured committed revolving credit facility, maturing May 2013, that is available for general corporate purposes.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2012, the Corporation's credit ratings were as follows:

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

In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget, S&P and DBRS also removed the ratings from 'credit watch with negative implications' and 'under review with developing implications', respectively, where the ratings had been placed in February 2012.

The above-noted credit ratings reflect the Corporation's business-risk profile and the diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

Market Risk

Foreign Exchange Risk

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

As at December 31, 2012, the Corporation's corporately issued US$557 million (December 31, 2011 – US$550 million) long-term debt had been designated as a hedge of the Corporation's foreign net investments. As at December 31, 2012, the Corporation had approximately US$17 million (December 31, 2011 – US$6 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 borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective from June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity (Notes 9 and 35) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. In 2012 the Corporation recognized in earnings a foreign exchange loss of approximately $2 million. In 2011 the Corporation recognized in earnings a net foreign exchange gain of approximately $1 million ($1.5 million after tax) (Note 24).

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with credit facility borrowings and floating-rate debt. The Corporation and the subsidiaries may enter into interest rate swap agreements to help reduce this risk.

Commodity Price Risk

The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas and Caribbean Utilities is exposed to commodity price risk associated with changes in the market price for fuel (Note 32). The risks have been reduced by entering into natural gas derivatives and fuel option contracts that effectively fix the price of natural gas purchases and fuel purchases, respectively. The natural gas derivatives and fuel option contracts are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

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

Notes to Consolidated Financial Statements

For the years ended December 31, 2012 and 2011

34. Commitments

As at December 31, 2012, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 15 and 16, respectively, are as follows:

(in 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
Interest obligations on long-term debt	**$ 6,682**	$ 355	$ 344	$ 311	$ 297	$ 271	$ 5,104
Government loan obligations (1)	**29**	4	10	10	5	–	–
Gas purchase contract obligations (2)	**249**	207	42	–	–	–	–
Power purchase obligations							
FortisBC Electric (3)	**34**	13	7	6	5	3	–
FortisOntario (4)	**360**	48	49	50	52	53	108
Maritime Electric (5)	**140**	38	40	40	8	1	13
Capital cost (6)	**446**	17	18	18	18	17	358
Operating lease obligations (7)	**26**	5	4	3	3	3	8
Waneta Partnership promissory note (8)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (9)	**62**	4	3	3	3	3	46
Defined benefit pension funding contributions (10)	**82**	38	16	12	12	1	3
PSU Plan obligations (11)	**6**	2	2	2	–	–	–
Other (12)	**7**	2	1	–	–	–	4
Total	**$ 8,195**	$ 733	$ 536	$ 455	$ 403	$ 352	$ 5,716

(1) In prior years, FEVI received non-interest bearing repayable loans from the Canadian federal government and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government financing, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure.

(2) Gas purchase contract obligations include various gas purchase contracts at the FortisBC Energy companies and are based on market prices that vary with gas commodity indices. The obligations include the gross cash payments associated with the FortisBC Energy companies' natural gas commodity derivatives (Note 31). The amounts disclosed reflect index prices that were in effect as at December 31, 2012.

(3) Power purchase obligations for FortisBC Electric are comprised of a PPA with BC Hydro, a capacity agreement with Powerex Corp. ("Powerex") and a capacity and energy purchase agreement with Brilliant Expansion Power Corporation ("Brilliant Corporation").

The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

In 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. The capacity being purchased under the agreement does not relate to a specific plant.

In November 2012 FortisBC Electric entered into an agreement to purchase capacity and energy from January 2013 through to December 2017 from CPC acting on behalf of Brilliant Corporation. The agreement was accepted by the BCUC in December 2012.

Notes to Consolidated Financial Statements

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount expected to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing was not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA. The amount associated with the WECA has not been included in the Commitments table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

(4) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 gigawatt hours ("GWh") of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(5) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In 2010 the Company signed a five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The contract includes fixed pricing for the entire five-year period. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(6) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases.

(8) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $47 million as at December 31, 2012 (Note 17).

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2017 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time.

FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. FortisAlberta has provided the necessary notice to terminate the shared-service agreements effective December 31, 2013.

(10) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2012 and 2013 – FortisBC Energy companies (plans covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (plan covering unionized employees)
December 31, 2013 – FortisBC Electric
December 31, 2014 – Newfoundland Power

The estimate of defined benefit pension funding contributions includes the impact of the outcome of the December 31, 2011 actuarial valuation, completed in April 2012, associated with the defined benefit pension plan at Newfoundland Power. As a result of the valuation, Newfoundland Power is required to fund a solvency deficiency of approximately $53 million, including interest, over five years beginning in 2012, which is reflected in the Commitments table above. The Company fulfilled its 2012 annual solvency deficit funding requirement during the second quarter of 2012. The increase in funding contributions is expected to be recovered from customers in future rates.

Notes to Consolidated Financial Statements

34. Commitments (cont'd)

(11) The settlement of PSUs outstanding as at December 31, 2012, which were granted in each of 2010, 2011 and 2012, are subject to the President and CEO of Fortis satisfying certain payment requirements over the three-year vesting periods (Note 23).

The Corporation's $6 million liability related to outstanding DSUs as at December 31, 2012 (Note 23) has been excluded from the Commitments table above, as the timing of the payments is indeterminable at this time.

(12) Other contractual obligations include building operating leases, AROs, fuel option contracts at Caribbean Utilities and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

Other Commitments

Capital expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecasted to be approximately $1.3 billion for 2013. Over the five years 2013 through 2017, the Corporation's consolidated capital expenditure program, including capital spending at Central Hudson, is expected to total $6 billion, which has not been included in the Commitments table above.

Pending Acquisitions: In February 2012 Fortis entered into an agreement to acquire CH Energy Group for US$1.5 billion, including the assumption of approximately US$500 million in debt on closing (Note 1). The agreement and plan of merger may be terminated by the Corporation or CH Energy Group at any time prior to closing in certain circumstances, including if the acquisition has not closed by February 20, 2013, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to August 20, 2013. In February 2013 the date was extended to August 20, 2013.

FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets, which currently serve some 15,000 customers, for approximately $55 million. FortisBC Electric provides the City of Kelowna with electricity under a wholesale tariff and has operated and maintained the City of Kelowna's electrical utility assets under contract since 2000. In March 2013 the regulator approved the transaction and determined the value of the assets for inclusion in FortisBC Electric's rate base to be approximately $38 million. FortisBC Electric is considering whether to proceed with the transaction and must confirm its acceptance of the conditions of the BCUC approval by March 31, 2013.

Subscription Receipts Offering: To finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18.5 million Subscription Receipts at $32.50 each in June 2012, realizing gross proceeds of approximately $601 million. Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of Release Conditions and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts to holders of record. If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount (Note 18). Closing of the acquisition of CH Energy Group subsequent to June 30, 2013 could result in the Corporation having to raise alternative capital to finance the transaction.

Other: In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes liquefied natural gas storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest (Note 22). The non-controlling interests hold put options which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

In 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under each of the contracts for the operation of Caribbean Utilities' diesel-powered generating plant. The approximate combined quantities under the contracts, expressed in millions of imperial gallons, on an annual basis by fiscal year are: 2013 – 32.4 and 2014 – 18.9. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

FortisTCI has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $681 million as at December 31, 2012 have been excluded from the Commitments table above, as the final timing of the settlement of many of the liabilities is subject to a further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 7.

The FortisBC Energy companies have issued commitments to customers to provide Energy Efficiency and Conservation funding under the respective program approved by the BCUC. As at December 31, 2012, approximately $5 million of funding had been committed to customers.

35. Expropriated Assets

Belize Electricity

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

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined by the independent valuators. The GOB also commissioned a valuation of Belize Electricity which is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset. While Fortis and representatives and third-party consultants of the GOB have held discussions in 2012 on differences in assumptions used in the valuations, there have been no discussions on any compensation settlement amount.

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

Fortis believes it has a strong, well-positioned case before the Belize Courts supporting the unconstitutionality of the expropriation. There exists, however, a reasonable possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of its expropriated investment in Belize Electricity. The book value was $104 million, including foreign exchange impacts, as at December 31, 2012 (December 31, 2011 – $106 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis, for example: (i) the ordering of the return of the shares to Fortis and/or award of damages; or (ii) the ordering of compensation to be paid to Fortis for the unconstitutional expropriation of the shares. Based on presently available information, the long-term other asset is not deemed impaired as at December 31, 2012. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations, if any. As well as continuing the constitutional challenge of the expropriation, Fortis is also pursuing alternative options for obtaining fair compensation, including compensation under the Belize/UK Bilateral Investment Treaty.

Exploits Partnership

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy, a Crown corporation, acting as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. The book value of the Corporation's net investment in the Exploits Partnership is approximately $4 million and is recorded in long-term other assets on the consolidated balance sheets. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

36. Contingent Liabilities

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

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

Fortis

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

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from CRA for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI is appealing the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions. FHI was advised that all matters have now been settled and the action has been dismissed by consent.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $15 million in damages as well as pre-judgment interest, but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 in relation to the same matter, which claims have now been settled. FortisBC Electric and its insurers continue to defend the claim by the Government of British Columbia. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

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

37. Comparative Figures

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes in presentation were as follows:

(i) During the first quarter of 2012, finance obligations as at December 31, 2011 were reclassified from current and long-term debt to current and long-term capital lease and finance obligations. The result was a decrease in current and long-term debt of $4 million and $120 million, respectively, and corresponding increases in current and long-term capital lease and finance obligations.

(ii) During the fourth quarter of 2012, the Corporation changed its presentation of the accumulated provision for salvage proceeds on disposal of regulated utility capital assets from long-term regulatory liabilities to accumulated depreciation. The change was applied retroactively, with restatement of December 31, 2011 balances. The effect of this change in presentation in the fourth quarter was an increase in each of long-term regulatory liabilities and utility capital assets, through a decrease in accumulated depreciation, of $59 million (December 31, 2011 – $50 million) and an increase in each of long-term regulatory assets and long-term deferred income tax liabilities of $6 million (December 31, 2011 – $6 million).

(iii) During the fourth quarter of 2012, the Corporation changed its presentation of deferred income taxes related to non-ARO removal costs from long-term regulatory liabilities to long-term deferred income taxes. The change in presentation was applied retroactively, with restatement of December 31, 2011 balances. The effect of this change in presentation in the fourth quarter was an increase in long-term regulatory liabilities of $52 million (December 31, 2011 – $51 million), an increase in long-term regulatory assets of $31 million (December 31, 2011 – $30 million) and a decrease in long-term deferred income tax liabilities of $21 million (December 31, 2011 – $21 million).

(iv) During the fourth quarter of 2012, the Corporation changed its presentation of deferred income taxes relating to regulatory assets and liabilities at the FortisBC Energy companies. The change in presentation was applied retroactively, with restatement of December 31, 2011 balances and resulted in the reclassification of various regulatory asset and liability balances to the deferred income taxes regulatory deferral account designated specifically for regulatory assets and liabilities (Note 7 *(i)*). The effect of this change in presentation in the fourth quarter was a decrease of approximately $40 million in each of long-term regulatory liabilities and long-term regulatory assets (December 31, 2011 – $37 million) and an increase of $3 million in each of current regulatory liabilities and current regulatory assets (December 31, 2011 – $7 million).

(v) During the fourth quarter of 2012, the liability for unrecognized tax benefits was reclassified from long-term other liabilities to long-term deferred income taxes. The result of this change was a decrease in long-term other liabilities of $16 million (December 31, 2011 – $22 million) and a corresponding increase in long-term deferred income taxes.

(vi) During the fourth quarter of 2012, the defined benefit pension liability as at December 31, 2011 was reclassified from accounts payable and other current liabilities to long-term other liabilities, resulting in a decrease in accounts payable and other current liabilities of $13 million and a corresponding increase in long-term other liabilities.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2012** [1]	2011 [1] [2]	2010 [1]
Revenue	**3,654**	3,738	3,647
Energy supply costs and operating expenses	**2,390**	2,547	2,448
Depreciation and amortization	**470**	416	406
Other income, net	**4**	38	13
Finance charges	**366**	363	359
Income taxes	**61**	84	72
Net earnings	**371**	366	375
Net earnings attributable to non-controlling interests	**9**	9	10
Net earnings attributable to preference equity shareholders	**47**	46	45
Net earnings attributable to common equity shareholders	**315**	311	320
Balance Sheets *(in $ millions)*			
Current assets	**1,093**	1,132	1,205
Goodwill	**1,568**	1,565	1,561
Other long-term assets	**1,715**	1,580	1,309
Utility capital assets, income producing properties and intangible assets	**10,574**	9,937	9,336
Total assets	**14,950**	14,214	13,411
Current liabilities	**1,308**	1,305	1,491
Other long-term liabilities	**2,449**	2,281	1,977
Long-term debt (excluding current portion)	**5,783**	5,685	5,616
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**9,540**	9,271	9,084
Shareholders' equity	**5,410**	4,943	4,327
Cash Flows *(in $ millions)*			
Operating activities	**976**	915	742
Investing activities	**1,080**	1,115	980
Financing activities	**396**	386	451
Dividends, excluding dividends on preference shares classified as debt	**225**	206	189
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.06**	8.79	10.06
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**55.3**	57.1	60.4
Preference shares (classified as debt and equity)	**9.7**	8.3	8.7
Common shareholders' equity	**35.0**	34.6	30.9
Interest Coverage *(x)*			
Debt	**2.0**	2.0	2.0
All fixed charges	**2.0**	2.0	2.0
Total gross capital expenditures *(in $ millions)*	**1,130**	1,171	1,071
Common share data			
Book value per share (year end) *($)*	**20.84**	20.25	18.65
Average common shares outstanding *(in millions)*	**190.0**	181.6	172.9
Basic earnings per common share *($)*	**1.66**	1.71	1.85
Dividends declared per common share *($)*	**1.210**	1.170	1.410
Dividends paid per common share *($)*	**1.200**	1.160	1.120
Dividend payout ratio *(%)*	**72.3**	67.8	60.5
Price earnings ratio *(x)*	**20.6**	19.5	18.4
Share trading summary (TSX)			
High price *($)*	**34.98**	35.45	34.54
Low price *($)*	**31.70**	28.24	21.60
Closing price *($)*	**34.22**	33.37	33.98
Volume *(in thousands)*	**115,962**	126,341	120,855

[1] Financial information for the years 2010 through 2012 has been prepared in accordance with US GAAP. Financial information prior to 2010 has been prepared in accordance with Canadian GAAP.

[2] Certain 2011 comparative figures have been reclassified to comply with current period classifications. Refer to Note 37 of the 2012 Annual Consolidated Financial Statements for further details.

[3] As at December 31, 2006, the regulatory provision for non-ARO removal costs was reallocated from accumulated depreciation to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric, due to a change in presentation adoped by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2009	2008	2007	2006 [3]	2005 [3]	2004	2003
3,641	3,907	2,718	1,472	1,441	1,146	843
2,577	2,859	1,904	939	926	766	579
364	348	273	178	158	114	62
10	–	8	2	10	–	–
369	363	299	168	154	122	86
49	65	36	32	70	47	38
292	272	214	157	143	97	78
12	13	15	8	6	6	4
18	14	6	2	–	–	–
262	245	193	147	137	91	74
1,124	1,150	1,038	405	299	293	191
1,560	1,575	1,544	661	512	514	65
917	487	424	331	471	418	345
8,538	7,954	7,276	4,049	3,315	2,713	1,563
12,139	11,166	10,282	5,446	4,597	3,938	2,164
1,592	1,697	1,804	558	412	538	296
1,325	763	732	508	503	164	62
5,239	4,848	4,588	2,532	2,110	1,879	1,031
320	320	320	320	320	320	123
8,476	7,628	7,444	3,918	3,345	2,901	1,512
3,663	3,538	2,838	1,528	1,252	1,037	652
681	661	373	263	304	272	157
1,045	852	2,033	634	467	1,026	308
563	387	1,826	456	224	777	232
176	191	146	77	64	51	38
8.41	8.70	10.00	11.87	12.40	11.28	12.30
60.2	59.5	64.3	61.1	58.7	61.4	60.0
6.9	7.3	5.2	10.0	8.6	9.4	6.7
32.9	33.2	30.5	28.9	32.7	29.2	33.3
1.9	1.9	1.9	2.2	2.5	2.3	2.2
1.8	1.8	1.7	2.0	2.1	2.0	2.1
1,024	935	803	500	446	279	208
18.61	17.97	16.69	12.19	11.74	10.45	8.82
170.2	157.4	137.6	103.6	101.8	84.7	69.3
1.54	1.56	1.40	1.42	1.35	1.07	1.06
0.780	1.010	0.880	0.700	0.605	0.548	0.525
1.040	1.000	0.820	0.670	0.588	0.540	0.520
67.5	64.1	58.6	47.2	43.7	50.3	48.9
18.6	15.8	20.7	21.0	18.0	16.2	13.9
29.24	29.94	30.00	30.00	25.64	17.75	15.24
21.52	20.70	24.50	20.36	17.00	14.23	11.63
28.68	24.59	28.99	29.77	24.27	17.38	14.73
121,162	132,108	100,920	60,094	37,706	29,254	31,180

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 17, 2013	August 16, 2013
November 15, 2013	February 14, 2014

Dividend Payment Dates

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

Earnings Release Dates

May 7, 2013	August 1, 2013
November 1, 2013	February 6, 2014

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

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Thursday, May 9, 2013
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; and Subscription Receipts of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J and FTS.R, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

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E: investorrelations@fortisinc.com

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President and Chief Executive Officer

Barry V. Perry
Vice President, Finance and Chief Financial Officer

Ronald W. McCabe
Vice President, General Counsel and Corporate Secretary

Donna G. Hynes
Assistant Secretary and Manager, Investor and Public Relations

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Printer:
The Lowe-Martin Group, Ottawa, ON

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St. John's, Newfoundland and Labrador

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Calgary, Alberta

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Corporate Director
Halifax, Nova Scotia

✻ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies please visit www.fortisinc.com.

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