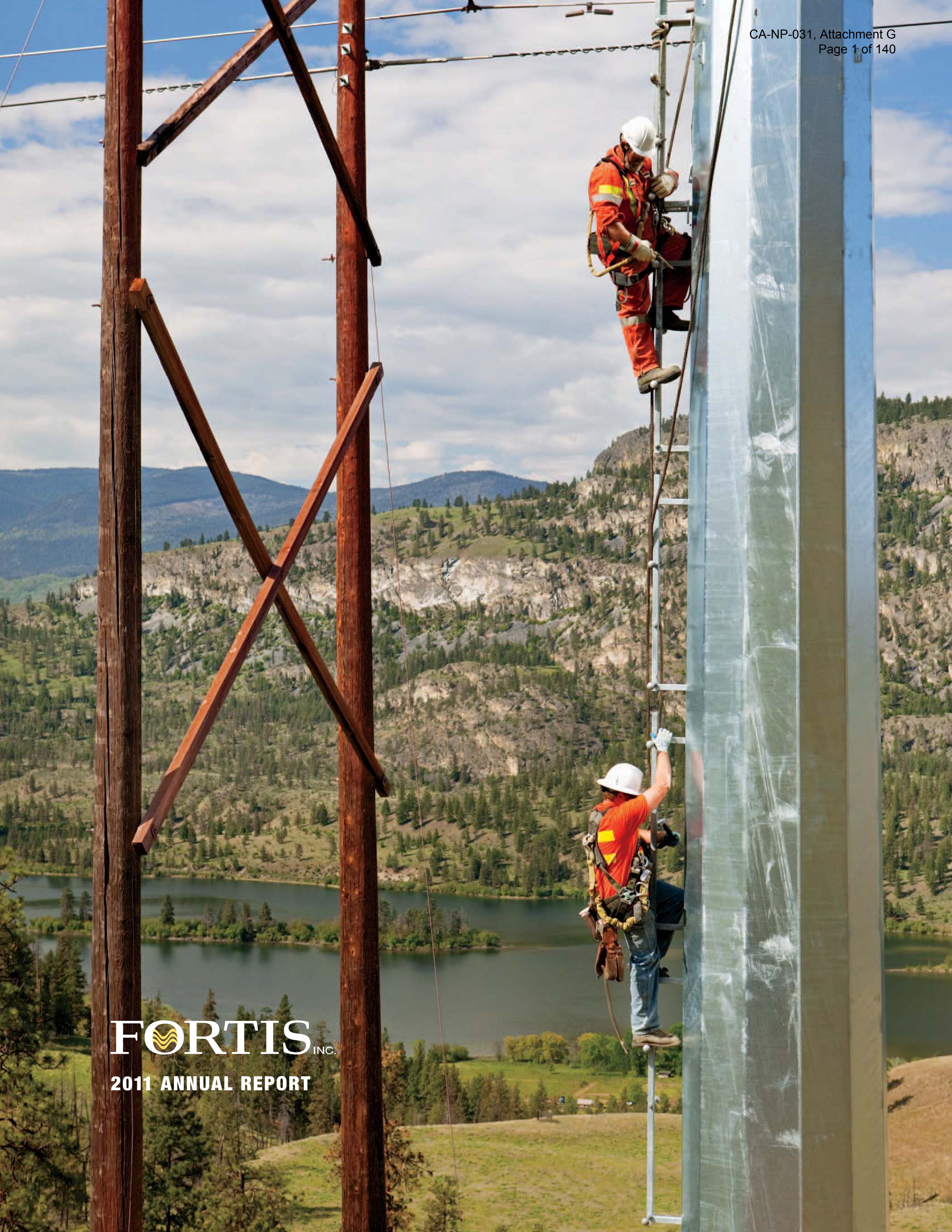
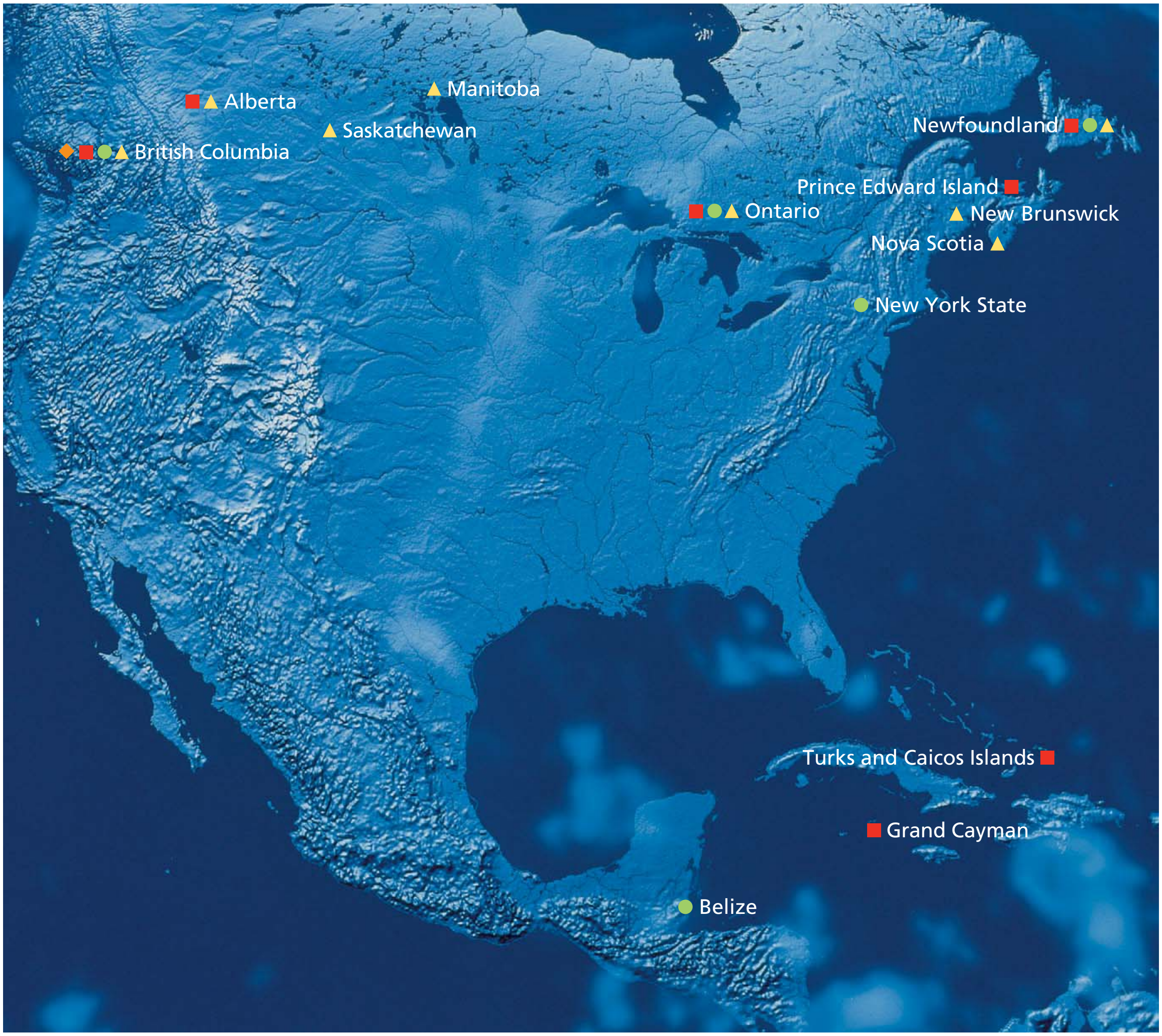
Fortis Inc. 2011 Annual Report



FORTIS INC.

2011 ANNUAL REPORT

Operations



Regulated Utility Operations

Gas Operations

FortisBC *British Columbia*

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*

Non-Regulated Operations

Fortis Generation

Production Areas

Belize, Ontario, Central Newfoundland, British Columbia, New York State

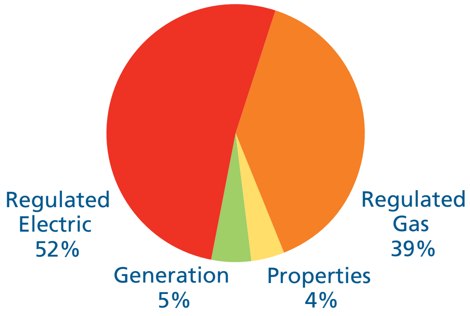
Fortis Properties

Real Estate and Hotels

Across Canada

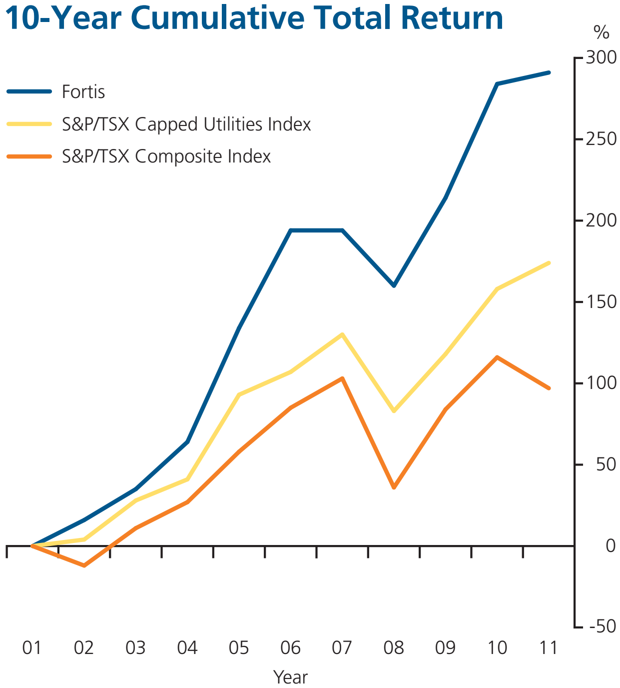
Total Assets $13.6 Billion

(as at December 31, 2011)



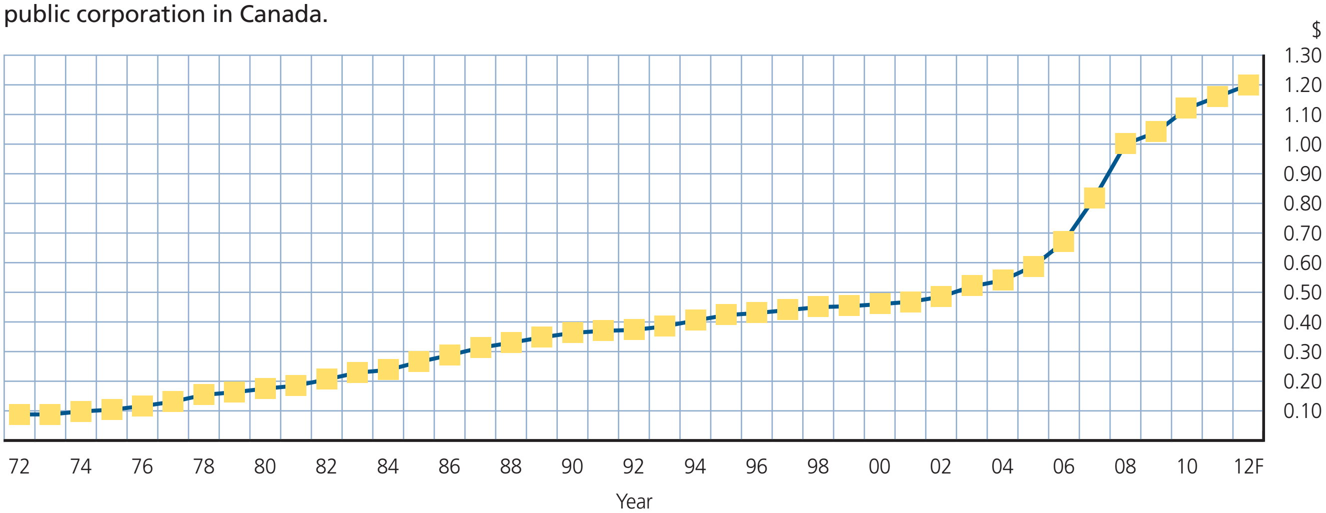
Contents

10-Year Cumulative Total Return



Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 39 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:

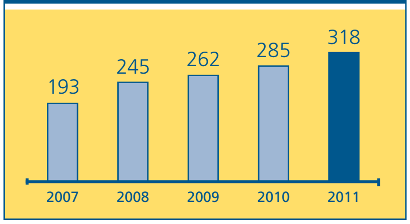
i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

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

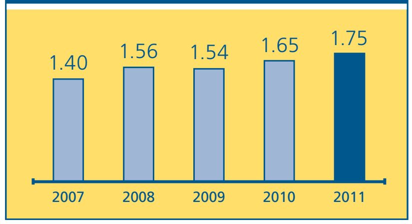
iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

Investor Highlights

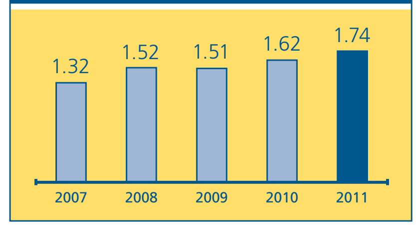
Earnings Attributable to Common Equity Shareholders ($M)



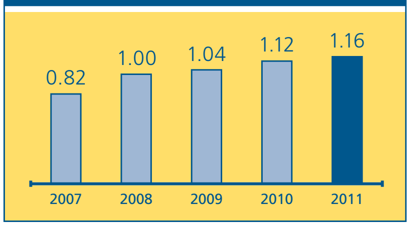
Basic Earnings per Common Share ($)



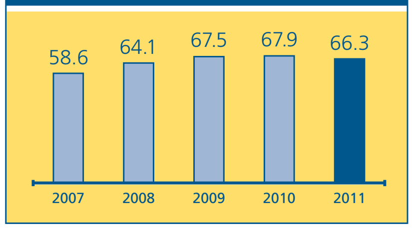
Diluted Earnings per Common Share ($)



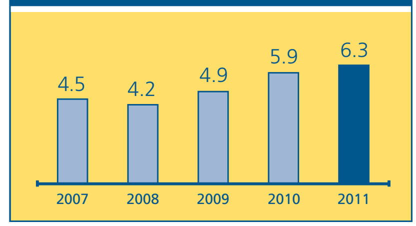
Dividends Paid per Common Share ($)



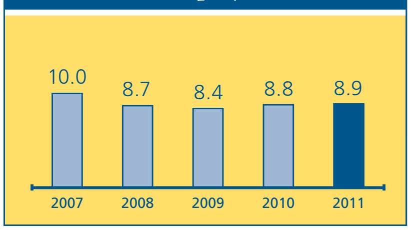
Dividend Payout Ratio (%)



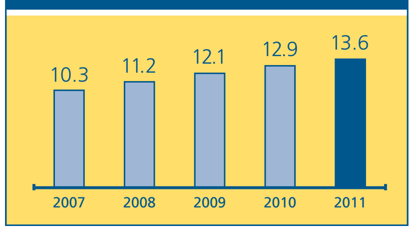
Market Capitalization ($B)



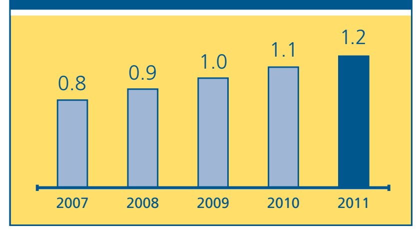
Return on Average Book Common Shareholders' Equity (%)



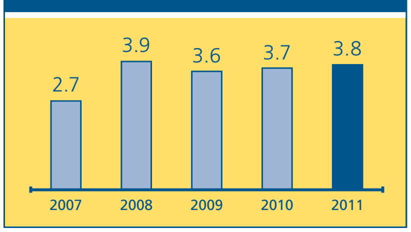
Assets ($B)



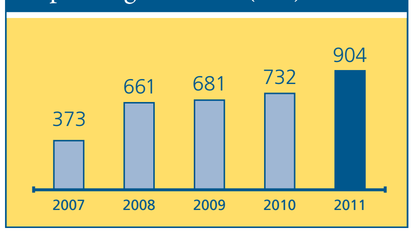
Capital Expenditures ($B)



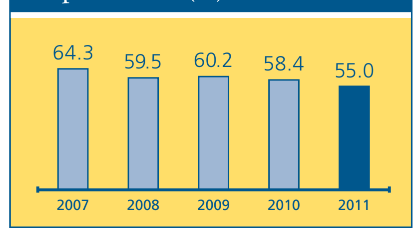
Revenue ($B)



Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2011 unless otherwise indicated.

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] 2011	2012
Total	**956,000**	**1,789**	**1,210**	**203**	**253**	**5.3**	**3.6**	**139**	**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] 2011	2012
FortisAlberta	499,000	1,036	2,505	16,367	416	2.7	2.0	75	8.75	8.75
FortisBC	162,000	528	669	3,143	102	1.6	1.1	48	9.90	9.90 [4]
Newfoundland Power	247,000	640	1,166	5,553	81	1.2	0.9	34	8.38	8.38 [5]
Maritime Electric	75,000	181	224	1,048	27	0.4	0.3	12	9.75	9.75
FortisOntario	64,000	198	276	1,318	20	0.3	0.2	10	8.01/9.85 [6]	8.01/9.85 [6]
Belize Electricity [7]	–	–	76	194	9	0.1	–	–	–	–
Caribbean Utilities [8]	27,000	193	99	554	36	0.5	0.4	11	7.75–9.75 [9]	7.75–9.75 [9] [10]
Fortis Turks and Caicos	9,500	114	30	170	26	0.2	0.2	9	17.50 [9] [11]	17.50 [9] [11]
Total	**1,083,500**	**2,890**	**5,045**	**28,347**	**717**	**7.0**	**5.1**	**199**		

(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 2012

(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) The allowed ROEs are to be maintained for 2012 pending determinations made in the regulator-initiated Generic Cost of Capital Proceeding, which will commence in March 2012.

(5) Interim, pending the outcome of a cost of capital review expected during 2012

(6) Canadian Niagara Power 8.01%; Algoma Power 9.85%

(7) Peak demand, energy sales and capital program are up to June 20, 2011, the date Belize Electricity was expropriated by the Government of Belize. Assets represent book value of the Corporation's previous investment in Belize Electricity. Fortis has filed for compensation from the Government of Belize for the fair value of Belize Electricity.

(8) 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.

(9) Regulated rate of return on rate base assets ("ROA")

(10) Subject to change based on the annual operation of the rate-cap adjustment mechanism to be finalized in June 2012

(11) Amount provided under licence. ROA achieved in 2011 was 6.6%. In February 2012 the Interim Government of the Turks and Caicos Islands approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Non-Regulated

Fortis Generation [1]

	Generating Capacity (MW)	Energy Sales (GWh)	Assets ($B) [3]	Earnings ($M) [4]	Capital Program ($M) [5]
Total	**139**	**389**	**0.7**	**18**	**174**

Fortis Properties [2]

	Employees (#)	Assets ($B)	Earnings ($M)	Capital Program ($M)
Total	**2,400**	**0.6**	**23**	**30**

(1) Includes investments in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

(2) Includes approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada and 22 hotels across Canada

(3) Includes $90 million in "Other" non-regulated assets

(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2011

(5) Includes $169 million related to the Waneta Expansion hydroelectric generating facility in British Columbia

Information is for the fiscal year ended December 31, 2011 unless otherwise indicated.

Report to Shareholders

2011 marks the 12th consecutive year Fortis has delivered record earnings to our shareholders. Net earnings attributable to common equity shareholders were $318 million, $33 million higher than earnings of $285 million in 2010. Earnings per common share were $1.75 in 2011 compared to $1.65 in 2010.

Stan Marshall,
President and CEO, Fortis Inc.

David Norris,
Chair of the Board, Fortis Inc.

Increased investment in energy infrastructure at our utilities in western Canada and the $11 million after-tax fee paid to Fortis in July 2011, following the termination of the Merger Agreement with Central Vermont Public Service Corporation ("CVPS"), were the primary drivers of earnings growth.

Dividends per common share have grown at a compound annual growth rate of 9.5% over the past 10 years. In December Fortis increased its quarterly common share dividend to 30 cents, commencing with the first quarter dividend paid in 2012. The 3.4% increase in the quarterly common share dividend translates into an annualized dividend of $1.20 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada. The dividend payout ratio was 66% in 2011.

Fortis delivered an average annualized total return to shareholders of approximately 15% over the past 10 years, exceeding the S&P/TSX Capped Utilities and Composite Indices, which delivered annualized performance of approximately 11% and 7%, respectively, over the same period.

Our annual capital expenditure program reached a record $1.2 billion in 2011, including combined expenditures of over $900 million in British Columbia and Alberta. Growth in energy demand accounted for about 45% of the capital expenditures made during the year. The significant investment in energy infrastructure being made by our utilities is focused on ensuring we continue to meet our obligation to provide quality service to our customers.

FortisBC, through its operating businesses, delivers approximately 21% of the total energy consumed in British Columbia – the most energy delivered by any utility in the province. In 2011 FortisBC completed its $212 million 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island. The new facility, brought online late in the year, improves reliability and security of supply to gas customers during periods of system interruptions or increased energy demand. In addition, FortisBC completed its $105 million Okanagan Transmission Reinforcement Project, which involved upgrading an overhead electricity transmission line between Penticton and Vaseux Lake from 161 kilovolts ("kV") to a double-circuit 230-kV line and building a new 230-kV terminal substation in the Oliver area to help ensure the safe and reliable delivery of energy to customers. The Company's $110 million Customer Care Enhancement Project, which included the opening of two new customer service centres in Prince George and Burnaby, came into service at the beginning of 2012.

Construction of the $900 million 335-MW Waneta Expansion hydroelectric generating facility is progressing well.

Construction of the $900 million 335-megawatt Waneta Expansion hydroelectric generating facility (the "Waneta Expansion") on the Pend d'Oreille River in British Columbia is progressing well. Approximately $244 million has been invested in the Waneta Expansion since construction started in late 2010. Fortis holds a 51% interest in the Waneta Expansion and will operate and maintain the facility when it comes into service, slated for spring 2015. The facility output is to be sold under 40-year power purchase agreements with FortisBC and BC Hydro. British Columbia and the Pacific Northwest region provide good potential to pursue additional hydroelectric generation assets that complement the utility operations of Fortis in western Canada, deliver value to our shareholders and enhance service to our customers.

FortisAlberta is our fastest-growing Canadian utility. Its rate base has grown at a compound annual growth rate of 18% over the past five years. The Company continues to invest significant capital in its electricity network, which includes more than 100,000 kilometres of distribution lines, with over $400 million of capital expenditures in 2011 and a similar amount planned for 2012. In early 2011 FortisAlberta completed its $126 million Automated Metering Project, which reduces operating costs and helps customers better monitor and manage their monthly energy usage. The Company has also undertaken a Pole Management Program to replace 96,000 vintage poles to prevent risk of failure due to age. Approximately $335 million is projected to be invested in this initiative through expected completion in 2019. A significant portion of FortisAlberta's franchise territory overlaps with the prominent tight oil and shale gas developments in Alberta, especially the Bakken, Cardium and Duvernay areas, and our business is benefiting from building the energy infrastructure necessary to meet associated customer growth.

Canadian Regulated Gas Utilities delivered earnings of $139 million, up $9 million from $130 million for 2010. Excluding a favourable one-time $4 million item in 2010, earnings increased $13 million year over year. Results for 2011 reflected the impact of growth in energy infrastructure investment, lower-than-expected corporate income taxes, finance charges and amortization costs, and increased gas transportation volumes to the forestry and mining sectors, partially offset by lower-than-expected customer additions.

Regulated utility assets comprise 91% of the total assets of Fortis.

The majority of our gas customers have benefited from the downward trend in natural gas commodity prices. The improving supply and cost fundamentals of natural gas throughout North America, combined with its positive environmental attributes, make natural gas an attractive energy supply source for residential and industrial use and as a fuel for the transportation and power generation sectors.

Canadian Regulated Electric Utilities contributed earnings of $179 million, up $15 million from $164 million for 2010. The increase was driven by improved results at FortisAlberta and FortisBC Electric. The increase in earnings at FortisAlberta mainly resulted from growth in energy infrastructure investment associated with sustaining the electricity grid and customer growth, partially offset by a lower allowed rate of return on common shareholders' equity ("ROE") for 2011. The increase in earnings at FortisBC Electric resulted from growth in energy infrastructure investment, lower purchased power costs and higher electricity sales.

Construction of the $212 million 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was completed in 2011.

At our largest utilities, a number of significant regulatory processes were recently decided or are underway. The Alberta Utilities Commission ("AUC") released its Generic Cost of Capital ("GCOC") decision in December, setting the 2011 allowed ROE at 8.75%, down from 9.0% for 2010. The AUC decided that it would not introduce a formula to automatically adjust allowed ROEs on an annual basis. In this regard, the AUC approved the 8.75% ROE for 2012, along with setting the 2013 interim ROE at 8.75%. Also at FortisAlberta, a regulatory decision is pending related to the Negotiated Settlement Agreement for 2012 customer rates the Company filed in November, following from its 2012/2013 rate application. In addition, FortisAlberta filed its performance-based regulation ("PBR") proposal last July, following from the initiative of the AUC to reform utility rate regulation in Alberta and the regulator's expressed intention to apply a PBR formula to electricity distribution rates. The AUC's decision on PBR is expected in 2012. At FortisBC regulatory decisions are pending at the gas and electric utilities related to their 2012/2013 rate applications. The allowed ROEs for the utilities are to be maintained for 2012 pending determinations made in the regulator-initiated GCOC proceeding, which will commence in March 2012. Newfoundland Power received regulatory approval last December to suspend operation of the automatic adjustment formula used to set the Company's allowed ROE for 2012. Consequently, Newfoundland Power's allowed ROE will remain at 8.38% and current customer electricity rates will continue in effect, both on an interim basis, for 2012. A full cost of capital review is expected to occur in 2012.

Caribbean Regulated Electric Utilities contributed $20 million to earnings compared to $23 million for 2010. Electricity sales at Caribbean Utilities and Fortis Turks and Caicos continue to be impacted by a decline in customer energy consumption resulting from challenging economic conditions in the region and high fuel prices. There was no earnings contribution from Belize Electricity in 2011 due to the expropriation of the Corporation's investment in the utility in June by the Government of Belize ("GOB"). Earnings contribution from Belize Electricity during 2010 was approximately $1.5 million. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation for the value of its investment in Belize Electricity from the GOB.

Fortis utilities serve more than 2,000,000 gas and electricity customers.

Non-Regulated Fortis Generation contributed $18 million to earnings compared to $20 million for 2010. The decline in earnings largely resulted from decreased hydroelectric production in Belize due to lower rainfall. The Corporation retains its indirect ownership and control of the non-regulated hydroelectric generating subsidiary, Belize Electric Company Limited ("BECOL"), and the GOB has indicated it has no intention to expropriate BECOL.

Fortis Properties delivered earnings of $23 million compared to $26 million for 2010. However, results for 2010 were favourably impacted by lower income tax rates, which reduced future income taxes. Results for 2011 reflected lower contribution from the Hospitality Division, primarily due to lower occupancy at the Company's hotels in western Canada. Fortis Properties augmented its portfolio of hotel properties in October 2011 with the acquisition of the 160-room, full-service Hilton Suites Winnipeg Airport hotel for $25 million.

Corporate and other expenses were $61 million for 2011, $17 million lower than $78 million for 2010. Excluding the $11 million after-tax termination fee related to CVPS, corporate and other expenses were $6 million lower year over year, as a result of both decreased business development costs and finance charges.

The 160-room Hilton Suites Winnipeg Airport hotel was acquired for $25 million in 2011.

Report to Shareholders

Fortis and its four largest utilities continue to have strong investment-grade credit ratings. Fortis debt is currently rated A– by Standard & Poor's and A(low) by DBRS. The credit ratings reflect the Corporation's low business-risk profile, reasonable credit metrics and demonstrated ability to acquire and integrate regulated utility businesses.

Two new customer service centres in British Columbia were opened in early 2012.

Fortis and its regulated utilities raised $688 million of long-term capital in 2011. The Corporation received proceeds of $341 million from its public common share issue in mid-2011. These funds were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion Limited Partnership, in support of infrastructure investment, and for general corporate purposes. Consolidated long-term debt totalling $347 million was issued during the year at terms ranging from 15 to 50 years and at rates ranging from 4.25% to 5.118%. Generally, proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to support further capital spending, and for general corporate purposes.

Strong investment-grade credit ratings, ample credit facilities and low debt maturities continue to provide Fortis with flexibility in the timing of access to the debt and equity capital markets. Fortis has consolidated credit facilities of $2.2 billion, of which $1.9 billion was unused at year-end 2011. Approximately $2.1 billion of the total credit facilities are committed facilities, having maturities ranging from 2012 to 2015. The credit facilities are syndicated mostly with Canadian banks, with no one bank holding more than 20% of these facilities. As at December 31, 2011, the Corporation's long-term debt maturities and repayments are expected to average $270 million annually over the next five years.

The Corporation's continued record of growth and success is directly attributable to the thousands of talented and dedicated people who comprise the Fortis team. We extend sincere appreciation to all our employees for their commitment to providing our customers with quality service. We also express gratitude to our colleagues on the Board of Directors of Fortis for their continuing oversight and support.

We are focused on completing our $1.3 billion capital expenditure program for 2012. Over the next five years through 2016, our capital expenditure program is projected to total $5.5 billion, which will support continuing growth in earnings and dividends.

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of 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 transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in New York State's Mid-Hudson River Valley, whose operations are similar to our regulated utility operations in Canada. The acquisition, which is subject to CH Energy Group's common shareholders' approval, and regulatory and other approvals, is anticipated to close in approximately 12 months and is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

We remain disciplined and patient in our pursuit of electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders.

As always, our number one priority is to provide our customers with safe, reliable and cost-efficient energy service and to continue to meet their energy needs.

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

Dated March 13, 2012

FORWARD-LOOKING INFORMATION

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2011 Consolidated Financial Statements and Notes thereto included in the Fortis Inc. ("Fortis" or the "Corporation") 2011 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and is presented in Canadian dollars unless otherwise specified.

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 Corporation's focus on the United States and Canada 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 current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America; investment to harvest shale oil and gas in Alberta, Canada, is expected to continue and should favourably impact energy sales and rate base investment in FortisAlberta's service territory; the expectation that the Government of British Columbia's new Natural Gas Strategy should favourably impact natural gas throughput at the FortisBC Energy companies; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030; the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the next five years; 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 should 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; forecast midyear rate base for each of the Corporation's four large Canadian regulated utilities; 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 2012 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2012 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 2012; 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 2012; 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 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 2012; the expectation that electricity sales growth at the Corporation's regulated utilities in the Caribbean will be minimal for 2012; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; the expectation that FortisBC will continue efforts in 2012 to further integrate its gas and electricity businesses; the expectation that the Corporation's consolidated earnings and earnings per common share for 2012 will not be materially impacted by the transition to accounting principles generally accepted in the United States ("US GAAP"); the expectation of an increase in consolidated defined benefit net pension cost for 2012 and the fact that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future; and the expected timing of the closing of the acquisition of CH Energy Group, Inc. by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding one-time transaction expenses. 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 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 ("BECOL") 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 affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards ("IFRS") 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 ("IT") 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. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on allowed rates of return on common shareholders' equity of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risk associated with defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of IT infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2011.*

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.

TABLE OF CONTENTS

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 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 Upper New York State, and hotels and commercial office and retail space in Canada. In 2011 the Corporation's electricity distribution systems met a combined peak demand of 5,045 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ").

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. 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"). Generally, the ability of a regulated utility to recover prudently incurred costs of providing service and to earn the regulator-approved allowed rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; and (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer 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.

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 hotels and commercial office and retail space, 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, and are managed as a segment to ensure standard operating practices, to leverage expertise across the various jurisdictions and to allow the pursuit of additional non-regulated hydroelectric projects. 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 the financing of premiums paid on the acquisition 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 reporting segment operates as an autonomous unit, 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 by utility are as follows:

Regulated Gas Utilities – Canadian

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

FEI is the largest distributor of natural gas in British Columbia, serving approximately 852,000 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 more than 102,000 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 ("Whistler"), British Columbia, which provides service to more than 2,600 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 499,000 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 162,000 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 247,000 customers. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving more than 75,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to more than 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. 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 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Includes FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is an integrated electric utility and the principal distributor of electricity in the Turks and Caicos Islands, serving more than 9,500 customers. The Company has a combined diesel-powered generating capacity of 65 MW.

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. Effective 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 and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of this MD&A.

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

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 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:* Includes 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.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "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. The Exploits Partnership sells its output 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 and Risks – 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 expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia 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") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

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

Non-Regulated – Fortis Properties: Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and 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. This segment includes finance charges, including interest on debt incurred directly by Fortis and FortisBC Energy Holdings Inc. ("FHI") (formerly Terasen Inc.) and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). 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 proportionate consolidation method of accounting. The financial results of FortisBC Alternative Energy Services Inc. ("FAES") (formerly Terasen Energy Services Inc.) are also reported in the Corporate and Other segment. FAES is a non-regulated wholly owned subsidiary of FHI that provides alternative energy solutions.

CORPORATE VISION AND STRATEGY

The principal business of the Corporation is 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 of 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 gas and electricity 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 past 10 years, earnings per common share of Fortis have grown at a compound annual growth rate of 6.9%. Fortis delivered an average annualized total return to shareholders of approximately 15% over the past 10 years, exceeding the Standard and Poor's ("S&P")/Toronto Stock Exchange ("TSX") Capped Utilities and S&P/TSX Composite Indices, which delivered annualized performance of approximately 11% and 7%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Consolidated midyear regulated utility rate base of Fortis grew at a compound annual growth rate of 6.6% from 2007 to 2011. Fortis also pursues opportunities to acquire additional regulated utilities in the United States and Canada. The acquisition of the FortisBC Energy companies in May 2007, which almost doubled the size of the Corporation's assets at that time, has helped provide Fortis with a platform to acquire larger-sized regulated utilities. While there were no utility acquisitions by the Corporation in 2011 or 2010, Fortis did participate in two significant acquisition processes. In accordance with the terms of a Merger Agreement with Central Vermont Public Service Corporation ("CVPS") in the United States, Fortis received a $17 million fee (US$17.5 million) in July 2011, plus $1.9 million (US$2.0 million) for the reimbursement of expenses, from CVPS upon Fortis terminating the Merger Agreement. The favourable impact on the Corporation's consolidated earnings for 2011 was $11 million, or $0.06 per common share. In 2010 Fortis attempted to acquire a large regulated electric utility, also in the United States. Business development costs of approximately $4 million, net of tax, or $0.02 per common share, were incurred in 2010 in relation to this acquisition attempt.

The non-utility business operations of Fortis support the Corporation's utility growth and acquisition strategy. Once completed in spring 2015, the 335-MW Waneta Expansion is expected to increase earnings from the Non-Regulated – Fortis Generation segment 150% from earnings contributed by this segment in 2011. Fortis Properties is also expected to continue to grow in size and profitability, providing flexibility in financial and tax planning to the Corporation not generally possible with respect to utilities in Canada because of regulatory and public policy constraints. Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million in October 2011.

KEY TRENDS AND RISKS

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. Utilities must also address such issues as climate change, 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 Conference Board of Canada, Canada's electricity sector is expected to invest approximately $294 billion from 2010 to 2030 to maintain existing assets and meet market growth. The average annual investment of approximately $15 billion is higher than in any previous decade. Generation investments in Canada over the 20-year period are expected to be approximately $196 billion. These investments are to replace or repower assets at the end of their useful lives and to add new capacity. The majority of the proposed projects in Canada are renewable or low-emission energy sources. Canada faces $36 billion in transmission investments from 2010 to 2030. Approximately $62 billion of distribution investment is also expected over this period to maintain system quality and reliability and to expand to meet energy demand.

Three major trends that are expected to influence future costs in the energy distribution sector in Canada are: (i) investments required as a result of increasing levels of distributed generation, based on renewable energy technologies; (ii) investments associated with the development of a smart grid; and (iii) changing electricity requirements.

Distributed generation relates to generation assets that are downstream of transmission and major transformer substations. The use of solar and wind power, the most common types of distributed generation, results in the need to forecast variable energy supplies and develop appropriate facilities that enhance the ability to predict how much and when power will flow in each direction.

Smart grid initiatives to date have focused primarily on the retail customer. Ontario has installed smart meters for all residential and small commercial customers and other provinces have moved forward as well, including Alberta, where FortisAlberta completed the installation of smart meters in its service territory in 2011. The growing focus on distributed generation and small renewable generation downstream of the transmission grid will likely change the way the grid is operated and will require investment. In several jurisdictions, time-of-use meters are being deployed and time-of-use rates are in the early stage of development. Some key implications of deploying smart grid technology include the need to manage a large volume of data from the meter while ensuring the meters are secure and that customers have access to real-time data in order to manage their energy usage.

There are also trends that could reshape future distribution investment requirements. As consumers become more aware of their energy needs and as their energy consumption decisions change, utilities will need to adjust their distribution investment accordingly. The use of electric vehicles, for example, will change the electricity consumption characteristics of the locations where they are charged, requiring investment by utilities to accommodate the impact this will have on supplying the required electricity.

Natural Gas: The total estimate of natural gas resources in North America has increased dramatically over the past decade. The primary driver of higher gas resources is new natural gas discoveries in both conventional and unconventional fields. The most significant natural gas supply story in North America continues to be the development of shale gas resources. The emergence of shale gas is the result of technological advancements in drilling and production techniques that have allowed producers to unlock increasingly higher volumes of gas at lower costs. The current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America.

In February 2012 the Government of British Columbia released its new Natural Gas Strategy. The strategy enables the expansion of the production of liquefied natural gas ("LNG") in British Columbia. It recognizes the natural gas industry's role as a global climate solution and seeks to position British Columbia as a global leader in secure and sustainable natural gas investment, development and export. The strategy includes a focus on promoting natural gas in the transportation sector and includes a program to reduce emissions by using natural gas in heavy-duty vehicles. This strategy should favourably impact natural gas throughput at the FortisBC Energy companies.

Investment to harvest shale oil and shale gas in Alberta is expected to continue, which should favourably impact energy sales and rate base investment in FortisAlberta's service territory.

Ultimately the success of unconventional development in the North American natural gas supply is contingent on the interplay of technology, cost, environmental benefits and market prices for natural gas and other energy products and services.

Greenhouse Gas Emissions: Implemented and potential government legislation, driven by concerns over the impact of greenhouse gas ("GHG") emissions in contributing to climate change, has significant implications for the energy industry. Canada accounts for about 2% of the world's GHG emissions, as per Scotia Capital's April 2011 *Energy Infrastructure Outlook*. Canada has one of the cleanest electricity systems in the world, with three quarters of its energy supply having no GHG emissions. In 2009 the electricity sector in Canada was responsible for 14% of the country's GHG emissions, according to Environment Canada's *National Inventory Report 1990–2009*. 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 significance 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. There is no coal-fired generation within any of the Corporation's operations. The 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.

The 335-MW Waneta Expansion will be an example of a clean renewable energy source when it comes into service in spring 2015.

FEI is one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings. For example, FEI received approval from the British Columbia Utilities Commission ("BCUC") for a new renewable natural gas program, on a limited basis, for an initial two-year period ending in 2012. An equivalent of 10% of the subscribed customers' natural gas requirements will be sourced from local renewable energy projects feeding the gas supply network. As part of this program, FEI has received approval to activate two projects that upgrade raw biogas into biomethane, which is then added to FEI's distribution system. One of the projects is operational and has been injecting gas into FEI's distribution system since September 2010, while the other will be operational by the end of 2012. Use of biomethane will help reduce emissions from waste decomposition and will help address the Government of British Columbia's climate change goals, as described further in the "Business Risk Management – Environmental Risks" section of this MD&A.

The *Renewable Energy Act* (Prince Edward Island) required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the Company met in both 2010 and 2011. With the PEI Energy Accord (the "Accord") signed between the Government of PEI and Maritime Electric, both parties will work collaboratively to increase electricity produced on PEI from renewable energy sources, principally wind, and sold to Maritime Electric. The Government of PEI intends to install 30 MW of wind turbines on PEI by January 1, 2013, with a view to selling the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, completed on PEI in January 2012, is being purchased by the Government of PEI and, in turn, being sold to Maritime Electric.

Allowed ROEs: The chart below highlights the trend in the allowed ROEs at each of the Corporation's four largest regulated utilities.

Regulator-Approved Allowed ROEs

(%)	2008	2009	2010	2011	2012
FEI	8.62	8.47/9.50	9.50	9.50	9.50 (1)
FortisAlberta	8.75	9.00	9.00	8.75	8.75
FortisBC Electric	9.02	8.87	9.90	9.90	9.90 (1)
Newfoundland Power	8.95	8.95	9.00	8.38	8.38 (2)

(1) Maintained, pending determinations made in the regulator-initiated Generic Cost of Capital ("GCOC") Proceeding, which will commence in March 2012.
(2) Interim, pending the outcome of a full cost of capital review expected in 2012

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 has been continued in Alberta for 2011 and 2012, with an allowed ROE ordered by the Alberta Utilities Commission ("AUC") of 8.75% for these years. The BCUC issued preliminary notification in November 2011 to all regulated utilities in British Columbia that it plans to initiate a Generic Cost of Capital ("GCOC") Proceeding. The proceeding will commence in March 2012 and will review, among other things, cost of capital and whether the re-establishment of an ROE automatic adjustment mechanism is warranted. An ROE automatic adjustment mechanism was in effect at Newfoundland Power for 2011. In December 2011 the regulator approved Newfoundland Power's request to suspend the operation of the ROE automatic mechanism for 2012 and to review cost of capital in 2012.

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.

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

Expropriated Assets: On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. The consequential loss of control over the operations of Belize Electricity resulted in the Corporation discontinuing the consolidation method of accounting for the utility, effective June 20, 2011. The Corporation has classified the book value of the previous investment in Belize Electricity as a long-term other asset on the consolidated balance sheet. As at December 31, 2011, the long-term other asset, including foreign exchange impacts, totalled $106 million.

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Fortis continues to control and consolidate the financial statements of BECOL. For further information, refer to the "Business Risk Management – Investment in Belize" 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 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. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

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, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, 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 $2.2 billion in credit facilities, of which approximately $1.9 billion was unused as at December 31, 2011. 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 2012.

Western Canadian Economies: A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than those of other regions of Canada. As at December 31, 2011, regulated utility assets comprised 91% of total assets (December 31, 2010 – 92%) and regulated utility assets in western Canada comprised 77% of total regulated assets (December 31, 2010 – 76%). Organic earnings growth at the Corporation's regulated utilities in western Canada is driven by rate base growth at FortisAlberta and FortisBC Electric. Since they were acquired in May 2004, the combined rate base of FortisAlberta and FortisBC Electric has grown 155%.

Dividend Increases: Dividends per common share increased to $1.16 in 2011. Fortis increased its quarterly common share dividend to 30 cents, commencing with the first quarter dividend paid in 2012. The 3.4% increase in the quarterly common share dividend translates into an annualized dividend of $1.20 for 2012 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada. Fortis expects that its significant capital program should 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, 2011 (December 31, 2010 – 8%). 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 interruption 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, and the achieved ROA at Fortis Turks and Caicos has been significantly lower than that allowed under its licence due to significant capital investment occurring at the utility in recent years without corresponding increases in base customer electricity rates.

Prior to the global recession that commenced late in 2008, economic growth had been strong in the Corporation's service territories in the Caribbean. The global recession, however, negatively affected local economic conditions which, in turn, unfavourably impacted electricity sales growth beginning in 2009 and that impact is expected to continue.

Integration of the FortisBC Energy Companies and FortisBC Electric: Effective March 1, 2011, the Terasen Gas companies were renamed to operate under a common brand identity with FortisBC. The FortisBC gas and electricity businesses are currently led by one Chief Executive Officer and senior management team with one Board of Directors providing oversight. This approach ensures an integrated focus and strategy in the delivery of energy to customers. FortisBC will continue efforts in 2012 to further integrate the gas and electricity businesses.

Transition to Accounting Principles Generally Accepted in the United States: Fortis will be adopting accounting principles generally accepted in the United States ("US GAAP"), as opposed to the otherwise required adoption of International Financial Reporting Standards ("IFRS"), effective January 1, 2012. US GAAP provides the most useful and relevant presentation of the Corporation's financial results. The decision to transition to US GAAP is consistent with many Canadian investor- and government-owned regulated electric and gas utilities. The necessary exemption from the Ontario Securities Commission ("OSC") and approvals from lenders were obtained by Fortis and its reporting issuer subsidiaries allowing for the use of US GAAP for financial reporting purposes beginning in 2012. Fortis does not expect its consolidated earnings and earnings per common share for 2012 to be materially impacted by the transition to US GAAP; however, material increases in consolidated assets, liabilities and equity are expected, mainly due to differences from Canadian GAAP in the accounting treatment of pensions and capital leases, and the classification of the Corporation's preference shares.

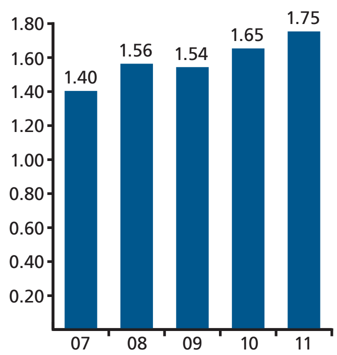
For further information with respect to the Corporation's transition to US GAAP, refer to the "Business Risk Management – Transition to New Accounting Standards" and "Future Accounting Changes" sections of this MD&A.

SUMMARY FINANCIAL HIGHLIGHTS

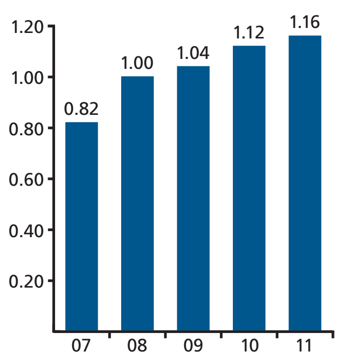
For the Years Ended December 31	**2011**	2010	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**318**	285	33
Basic Earnings per Common Share *($)*	**1.75**	1.65	0.10
Diluted Earnings per Common Share *($)*	**1.74**	1.62	0.12
Weighted Average Number of Common Shares Outstanding *(millions)*	**181.6**	172.9	8.7
Cash Flow from Operating Activities *($ millions)*	**904**	732	172
Dividends Paid per Common Share *($)*	**1.16**	1.12	0.04
Dividend Payout Ratio *(%)*	**66.3**	67.9	(1.6)
Return on Average Book Common Shareholders' Equity *(%)*	**8.9**	8.8	0.1
Total Assets *($ millions)*	**13,562**	12,909	653
Gross Capital Expenditures *($ millions)*	**1,174**	1,073	101
Public Common Share Offering *($ millions)*	**341**	–	341
Public Preference Share Offering *($ millions)*	**–**	250	(250)
Long-Term Debt Offerings *($ millions)*	**347**	525	(178)

Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $318 million in 2011, up $33 million from $285 million in 2010. The increase in earnings was due to the $11 million after-tax fee paid to Fortis following the termination of the Merger Agreement with CVPS combined with 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 amortization costs, and increased gas transportation volumes to the forestry and mining sectors at the FortisBC Energy companies, partially offset by lower-than-expected customer additions at these companies; (iii) higher capitalized allowance for funds used during construction ("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 amortization costs, partially offset by reduced energy supply costs in 2011; (ii) decreased earnings at Fortis Properties reflecting higher corporate income taxes and lower occupancies at hotels in western Canada; (iii) decreased earnings from non-regulated hydroelectric generation operations, largely due to lower production in Belize because of reduced rainfall, and overall lower interest income; (iv) lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with new joint-use pole support structure arrangements with Bell Aliant Inc. ("Bell Aliant") in 2011 and higher operating expenses, partially offset by reduced energy supply costs in 2011 and higher electricity sales; and (v) approximately $1 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated earnings due to the weakening of the US dollar relative to the Canadian dollar year over year.

Basic Earnings per Common Share *($)*



Dividends Paid per Common Share *($)*



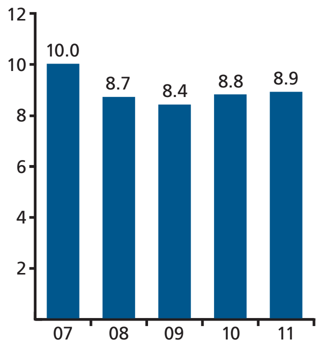
Basic Earnings per Common Share: Basic earnings per common share were $1.75 in 2011 compared to $1.65 in 2010. The increase was due to improved performance, partially offset by the impact of an increase in the weighted average number of common shares outstanding associated with the public common equity offering and shares issued under the Corporation's dividend reinvestment and stock option plans during 2011.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $904 million for 2011, up $172 million from $732 million for 2010. The increase was driven by favourable changes in working capital, mainly related to accounts payable, accounts receivable and inventories driven by the FortisBC Energy companies and FortisAlberta, and higher earnings.

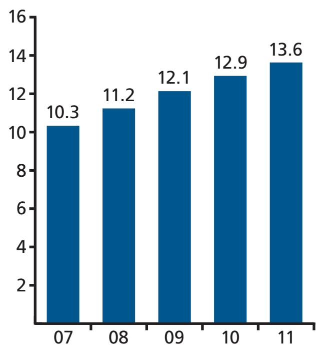
Dividends: Dividends paid per common share increased to $1.16 in 2011, up 3.6% from $1.12 in 2010. Fortis increased its quarterly common share dividend 3.4% to 30 cents from 29 cents, commencing with the first quarter dividend paid on March 1, 2012. The Corporation's dividend payout ratio was 66.3% in 2011 compared to 67.9% in 2010.

Management Discussion and Analysis

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



Total Assets *($ billions)*
(as at December 31)



Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity was 8.9% in 2011 compared to 8.8% in 2010. The increase largely related to higher net earnings attributable to common equity shareholders, partially offset by an increase in common equity.

Total Assets: Total assets increased 5% to approximately $13.6 billion at the end of 2011 compared to approximately $12.9 billion at the end of 2010. The increase reflected the Corporation's continued investment in regulated energy systems, driven by the capital expenditure programs at the FortisBC Energy companies, FortisAlberta and FortisBC Electric, the continued construction of the non-regulated Waneta Expansion in British Columbia and the favourable impact of foreign exchange associated with translation of foreign currency-denominated assets. The increase was partially offset by the impact of the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility effective June 20, 2011.

Gross Capital Expenditures: During 2011 consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,174 million, up $101 million from $1,073 million in 2010. Total capital investment at the regulated utilities in western Canada was approximately $771 million, representing approximately 66% 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. The larger capital projects during 2011 included the completion of the LNG storage facility at FEVI, the Okanagan Transmission Reinforcement Project at FortisBC Electric and the Automated Metering Project at FortisAlberta. Implementation of the Customer Care Enhancement Project at FEI continued in 2011 and came into service in January 2012. Construction of the non-regulated Waneta Expansion, which commenced late in 2010, and FortisAlberta's Pole Management Program also continued during 2011. For a further discussion of the Corporation's 2011 and 2012 consolidated capital expenditure plan, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: During 2011 Fortis and its regulated utilities raised $688 million of long-term capital. Mid-2011 Fortis issued approximately 10.3 million common shares for $341 million, the net proceeds of which were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion, in support of infrastructure investment, and for general corporate purposes. Total long-term debt raised in 2011 was $347 million and was comprised of: (i) 30-year $125 million 4.54% unsecured debentures at FortisAlberta; (ii) US$40 million unsecured notes at Caribbean Utilities for terms of 15 and 20 years and at rates of 4.85% and 5.10%; (iii) 30-year $100 million 4.25% unsecured debentures at FEI; (iv) 50-year $30 million 4.915% first mortgage bonds at Maritime Electric; and (v) 30-year $52 million 5.118% unsecured notes at FortisOntario. Generally, proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to support further capital spending, and for general corporate purposes. In the case of FortisOntario, the debt proceeds were used to repay an intercompany loan with Fortis originally incurred in support of the acquisition of Algoma Power in 2009.

CONSOLIDATED RESULTS OF OPERATIONS

The Corporation's consolidated results of operations for 2011 and 2010 are outlined below, including a discussion of the nature of the variances year over year.

Years Ended December 31 *($ millions)*	**2011**	2010	Variance
Revenue	**3,747**	3,657	90
Energy Supply Costs	**1,697**	1,686	11
Operating Expenses	**865**	822	43
Amortization	**419**	410	9
Other Income (Expenses), Net	**40**	13	27
Finance Charges	**370**	362	8
Corporate Taxes	**80**	67	13
Net Earnings	**356**	323	33
Net Earnings Attributable to:			
Non-Controlling Interests	**9**	10	(1)
Preference Equity Shareholders	**29**	28	1
Common Equity Shareholders	**318**	285	33
Net Earnings	**356**	323	33

Factors Contributing to Revenue Variance

Favourable

- 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 higher regulator-approved expenses recoverable from customers, and a higher allowed ROE at Algoma Power
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities
- Growth in the number of customers, mainly at FortisAlberta
- Higher gas sales
- Higher electricity sales at Canadian Regulated Electric Utilities
- The recognition of $3.5 million of accrued revenue at FortisAlberta in 2011, related primarily to the cumulative 2010 and 2011 allowed return and recovery of amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- 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
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant in 2011
- Increased performance-based rate-setting ("PBR")-incentive adjustments to be refunded to customers by FortisBC Electric

Factors Contributing to Energy Supply Costs Variance

Unfavourable

- Increased fuel prices at Caribbean Utilities
- Higher gas sales
- Higher electricity sales at Canadian Regulated Electric Utilities

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
- Lower purchased power costs at FortisBC Electric
- Approximately $8 million associated with favourable foreign currency translation

Factors Contributing to Operating Expenses Variance

Unfavourable

- Higher operating expenses at the FortisBC Energy companies, mainly due to increased wages and benefit costs and higher asset removal costs, partially offset by lower contractor and consulting expenses and labour savings associated with changes in staffing levels
- The regulator-approved reversal in the third quarter of 2010 at the FortisBC Energy companies of $5 million ($4 million after tax) of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Higher operating expenses at Newfoundland Power, mainly due to the regulator-approved change in the accounting treatment for other post-employment benefit ("OPEB") costs, wage and general inflationary cost increases, higher conservation costs related to customer rebate programs and increased employee-related expenses
- Higher operating expenses at FortisBC Electric, largely due to increased vegetation management costs, wage and general inflationary cost increases and higher property taxes

Favourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Operating costs of approximately $2 million incurred during the third quarter of 2010 at Newfoundland Power as a result of Hurricane Igor
- Higher capitalized general overhead expenses, mainly at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power
- Approximately $2 million associated with favourable foreign currency translation

Factors Contributing to Amortization Costs Variance

Unfavourable

- Continued investment in energy infrastructure and income producing properties

Favourable

- Reduced amortization costs in 2011 at the FortisBC Energy companies, mainly due to the retirement late in 2010 of certain general plant assets and the amortization in 2011 of a regulatory deferral account
- Regulator-approved increased amortization costs at Newfoundland Power in 2010, due to approximately $4 million of adjustments related to an amortization study
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $1.5 million associated with favourable foreign currency translation

Factors Contributing to Other Income (Expenses) Variance

Favourable

- The $17 million (US$17.5 million) fee paid to Fortis in July 2011 following the termination of the Merger Agreement with CVPS
- Lower corporate business development costs, due to $6 million incurred in the first half of 2010
- A net foreign exchange gain of $1 million associated with the previously hedged investment in Belize Electricity

Factors Contributing to Finance Charges Variance

Unfavourable

- Higher long-term debt levels in support of the utilities' capital expenditure programs

Favourable

- The refinancing of maturing corporate debt at lower rates
- Higher capitalized AFUDC, mainly at FortisAlberta, partially offset by lower capitalized AFUDC at FortisBC Electric
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011

Factors Contributing to Corporate Taxes Variance

Unfavourable

- Higher earnings before tax in taxable jurisdictions
- Lower deductions for income tax purposes compared to accounting purposes

Favourable

- Lower statutory income tax rates

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31

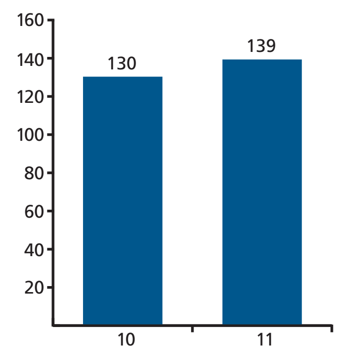
($ millions)	**2011**	2010	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**139**	130	9
Regulated Electric Utilities – Canadian			
FortisAlberta	***75***	*68*	*7*
FortisBC Electric	***48***	*42*	*6*
Newfoundland Power	***34***	*35*	*(1)*
Other Canadian Electric Utilities	***22***	*19*	*3*
	179	164	15
Regulated Electric Utilities – Caribbean	**20**	23	(3)
Non-Regulated – Fortis Generation	**18**	20	(2)
Non-Regulated – Fortis Properties	**23**	26	(3)
Corporate and Other	**(61)**	(78)	17
Net Earnings Attributable to Common Equity Shareholders	**318**	285	33

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 consolidated capital expenditure program and breakdown of actual 2011 and forecast 2012 gross capital expenditures by segment is provided in the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2011 regulated earnings in Canada and the Caribbean represented approximately 89% (2010 – 87%) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 91% of the Corporation's total assets as at December 31, 2011 (December 31, 2010 – 92%).

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



Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2011 were $139 million (2010 – $130 million), which represented approximately 41% of the Corporation's total regulated earnings (2010 – 41%). Regulated Gas Utilities – Canadian assets were approximately $5.3 billion as at December 31, 2011 (December 31, 2010 – $5.2 billion), which represented approximately 43% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 44%).

FortisBC Energy Companies

Gas Volumes by Major Customer Category

Years Ended December 31

(TJ)	**2011**	2010	Variance
Core – Residential and Commercial	**128,161**	113,635	14,526
Industrial	**5,544**	5,259	285
Total Sales Volumes	**133,705**	118,894	14,811
Transportation Volumes	**67,813**	60,363	7,450
Throughput Under Fixed Revenue Contracts	**1,237**	13,765	(12,528)
Total Gas Volumes	**202,755**	193,022	9,733

Factors Contributing to Gas Volumes Variance

Favourable

- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes reflecting improving economic conditions favourably affecting the forestry and mining sectors

Unfavourable

- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011

Net customer additions were 7,450 for 2011 compared to 9,393 for 2010. Net customer additions decreased year over year due to lower building activity.

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

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

FortisBC Energy Companies

Financial Highlights

Years Ended December 31

($ millions)	**2011**	2010	Variance
Revenue	**1,568**	1,546	22
Earnings	**139**	130	9

Factors Contributing to Revenue Variance

Favourable

- An increase in the delivery component of customer rates, mainly due to ongoing investment in energy infrastructure and forecasted higher regulator-approved operating expenses recoverable from customers
- Higher average gas consumption by residential and commercial customers
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower-than-expected customer additions

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Lower-than-expected corporate income taxes, finance charges and amortization costs in 2011
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

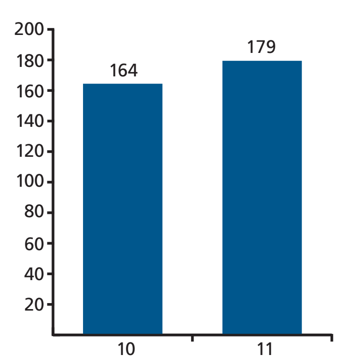
- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Lower-than-expected customer additions in 2011

Outlook: The allowed ROEs for the FortisBC Energy companies for 2012 remain unchanged from 2011 at 9.50% for FEI and 10.00% for FEVI and FEWI. Customer delivery rates at the FortisBC Energy companies for 2012 have been approved on an interim basis, effective January 1, 2012, pending final decisions by the regulator on the utilities' 2012–2013 Revenue Requirements Applications. A regulator-initiated GCOC Proceeding in 2012 may result in a change in the utilities' capital structures and/or allowed ROEs.

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2011 were $179 million (2010 – $164 million), which represented approximately 53% of the Corporation's total regulated earnings (2010 – 52%). Regulated Electric Utilities – Canadian assets were approximately $6.1 billion as at December 31, 2011 (December 31, 2010 – $5.8 billion), which represented approximately 50% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 48%).

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



FortisAlberta

Financial Highlights

Years Ended December 31	**2011**	2010	Variance
Energy Deliveries *(GWh)*	**16,367**	15,866	501
Revenue *($ millions)*	**409**	385	24
Earnings *($ millions)*	**75**	68	7

Factors Contributing to Energy Deliveries Variance

Favourable

- Growth in the number of customers, with the total number of customers increasing by approximately 8,000 year over year, driven by favourable economic conditions
- Higher average consumption by farm and irrigation customers, due to differences in rainfall year over year
- Higher average consumption by residential customers, mainly due to cooler-than-normal temperatures during the first quarter of 2011

Unfavourable

- Lower average consumption by the gas sector, due to decreased activity as a result of low gas market prices

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

- The 4.7% increase in base customer electricity distribution rates, effective January 1, 2011. The increase in base rates was primarily due to ongoing investment in energy infrastructure.
- Growth in the number of customers
- The recognition in 2011 of accrued revenue of $3.5 million related primarily to the cumulative allowed return and recovery of amortization on the additional $22 million in capital expenditures approved by the regulator to be included in rate base associated with the Automated Metering Project. Approximately $1.5 million of the accrual related to 2010.

Unfavourable

- An approximate $2 million rate revenue reduction accrued during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE to 8.75% for 2011 from 9.00% for 2010
- Differences in the amortization to revenue of regulatory deferrals year over year, as approved by the regulator

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Higher capitalized AFUDC, due to a higher asset base under construction during 2011
- Growth in the number of customers and energy deliveries
- The allowed return and recovery of amortization of approximately $1.5 million recognized in 2011, relating to 2010, on the additional capital expenditures associated with the Automated Metering Project, as discussed above
- An approximate $1 million gain on the sale of property

Unfavourable

- The decrease in the allowed ROE for 2011, as discussed above
- Lower return earned on the Alberta Electric System Operator ("AESO") charges deferral, due to a decrease in the deferral balance

Outlook: FortisAlberta's allowed ROE of 8.75% for 2012 has been set by the regulator. Customer rates at FortisAlberta for 2012 have been approved on an interim basis, effective January 1, 2012, pending a final decision by the regulator on the utility's 2012 Distribution Tariff Application ("DTA").

FortisBC Electric

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**3,143**	3,046	97
Revenue *($ millions)*	**296**	266	30
Earnings *($ millions)*	**48**	42	6

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers
- Lower average consumption during the first quarter of 2010, due to warmer-than-average temperatures experienced during that period, resulting in higher electricity sales year over year

Factors Contributing to Revenue Variance

Favourable

- A 6.6% increase in customer electricity rates, effective January 1, 2011, mainly reflecting ongoing investment in energy infrastructure
- A 1.4% and a 2.9% increase in customer electricity rates, effective June 1, 2011 and September 1, 2010, respectively, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- The 3.2% increase in electricity sales
- Higher revenue contribution from non-regulated operating, maintenance and management services
- Higher wheeling revenue

Unfavourable

- Higher PBR-incentive adjustments to be refunded to customers
- Lower surplus electricity sales

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Lower-than-expected energy supply costs in 2011, primarily due to lower average market-priced purchased power costs
- Higher electricity sales
- Higher earnings contribution from non-regulated operating, maintenance and management services

Unfavourable

- Lower capitalized AFUDC due to a lower asset base under construction during 2011
- Higher effective corporate income taxes, mainly due to lower deductions for income tax purposes compared to accounting purposes

Outlook: FortisBC Electric's allowed ROE of 9.90% for 2012 remains unchanged from 2011. Customer rates for 2012 have been approved on an interim basis, effective January 1, 2012, pending a final decision by the regulator on the utility's 2012–2013 Revenue Requirements Application. A regulator-initiated GCOC Proceeding in 2012 may result in a change in the utility's capital structure and/or allowed ROE.

Newfoundland Power

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**5,553**	5,419	134
Revenue *($ millions)*	**573**	555	18
Earnings *($ millions)*	**34**	35	(1)

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers
- Higher average consumption, reflecting the higher concentration of electric-versus-oil heating in new home construction combined with strong economic growth

Factors Contributing to Revenue Variance

Favourable

- The 2.5% increase in electricity sales
- An overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly reflecting higher OPEB costs, partially offset by a decrease in the allowed ROE to 8.38% for 2011 from 9.00% for 2010

Unfavourable

- Decreased amortization to revenue of regulatory liabilities and deferrals, as approved by the regulator
- Lower joint-use pole-related revenue due to new support structure arrangements with Bell Aliant, effective January 1, 2011

Factors Contributing to Earnings Variance

Unfavourable

- The decrease in the allowed ROE, as reflected in customer rates
- Lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011
- Higher effective corporate income taxes, primarily due to lower deductions taken for income tax purposes compared to accounting purposes, partially offset by a lower statutory income tax rate
- Higher operating expenses related to wage and general inflationary cost increases, higher employee-related expenses and higher conservation costs related to rebate programs offered to customers, partially offset by lower storm-related costs

Favourable

- Electricity sales growth
- A reduction in energy supply costs in the fourth quarter of 2011 associated with the Company's hydroelectric generating facilities

Outlook: Newfoundland Power's customer rates and allowed ROE of 8.38% for 2011 will remain in effect for 2012, on an interim basis, pending the outcome of a full cost of capital review expected to occur in 2012.

Other Canadian Electric Utilities

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**2,366**	2,328	38
Revenue *($ millions)*	**339**	331	8
Earnings *($ millions)*	**22**	19	3

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of residential customers
- Higher average consumption by residential customers in Ontario and on PEI, reflecting colder temperatures, which increased home-heating load

Unfavourable

- Lower average consumption by industrial customers on PEI, due to a reduction in farm-crop storage and warehousing activities

Factors Contributing to Revenue Variance

Favourable

- An average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010, reflecting an increase in the allowed ROE to 9.85% for 2011 from 8.57% for 2010, and the use of a forward test year for rate setting
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- The 1.6% increase in electricity sales

Unfavourable

- A rate of return adjustment at Maritime Electric reducing revenue by approximately $2 million in the fourth quarter of 2011, driven by higher-than-expected electricity sales during 2011
- Lower basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs

Factors Contributing to Earnings Variance

Favourable

- A higher allowed ROE at Algoma Power and the use of a forward test year for rate setting, as reflected in customer rates for 2011
- Rate base growth due to continued investment in energy infrastructure
- Lower effective corporate income taxes, primarily due to higher deductions taken for income tax purposes compared to accounting purposes
- Electricity sales growth

Unfavourable

- The rate of return adjustment at Maritime Electric during the fourth quarter of 2011, as discussed above

Outlook: Maritime Electric's allowed ROE for 2012 of 9.75% remains unchanged from 2011. Largely reflecting lower power purchase costs, customer rates were reduced, effective March 1, 2011, at which time a two-year rate freeze commenced.

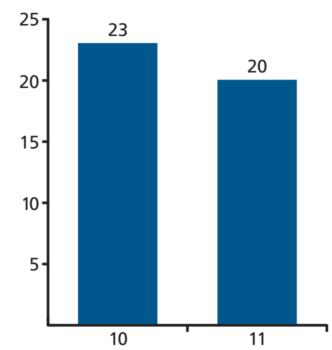
Both Algoma Power's allowed ROE for 2012 of 9.85% and Canadian Niagara Power's allowed ROE for 2012 of 8.01% remain unchanged from 2011.

Electricity distribution rate applications have been filed by Algoma Power and Canadian Niagara Power under the Third-Generation Incentive Rate Mechanism ("IRM") for customer rates effective May 1, 2012.

Regulated Electric Utilities – Caribbean

Earnings contribution from Regulated Electric Utilities – Caribbean for 2011 was $20 million (2010 – $23 million), which represented approximately 6% of the Corporation's total regulated earnings (2010 – 7%). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2011 (December 31, 2010 – $0.9 billion), which represented approximately 7% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 8%).

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



Financial Highlights

Years Ended December 31	2011	2010	Variance
Average US:CDN Exchange Rate [(1)]	**0.99**	1.03	(0.04)
Electricity Sales *(GWh)*	**918**	1,150	(232)
Revenue *($ millions)*	**305**	333	(28)
Earnings *($ millions)*	**20**	23	(3)

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

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. For further information, refer to the "Business Risk Management – Investment in Belize" section of this MD&A.
- Reduced energy consumption, due to challenging economic conditions in the region, the high cost of fuel and the early and extended closure of certain hotel and other commercial customers in the Turks and Caicos Islands resulting from a hurricane in August 2011
- The number of work permit holders in the region has declined significantly, causing some rental properties with active electricity connections to be vacant.
- Excluding Belize Electricity, there was no growth in electricity sales year over year.

Favourable

- Growth in the number of customers in Grand Cayman and the Turks and Caicos Islands

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
- Approximately $13 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

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the price of fuel

Factors Contributing to Earnings Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. There was no earnings contribution from Belize Electricity during 2011, while the Company contributed $1.5 million in earnings in 2010.
- Higher amortization, excluding the impact of foreign exchange, largely at Fortis Turks and Caicos, due to investment in utility capital assets, including the commencement of amortization in 2011 of a new operations centre and generating unit
- Higher operating expenses, excluding the impact of foreign exchange, at Fortis Turks and Caicos, largely due to consulting fees associated with ongoing regulatory matters and inflationary cost increases

Favourable

- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility

Outlook: Electricity sales growth at the Corporation's regulated utilities in the Caribbean is expected to be minimal for 2012, reflecting the expected continuation of the negative impact of challenging economic conditions on electricity consumption by customers in the Caribbean region.

NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

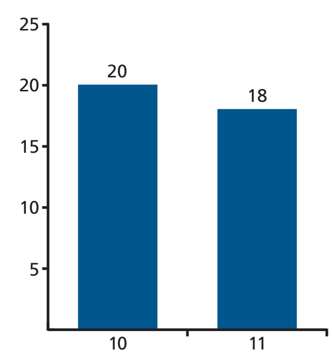
Years Ended December 31	**2011**	2010	Variance
Energy Sales *(GWh)*	**389**	427	(38)
Revenue *($ millions)*	**34**	36	(2)
Earnings *($ millions)*	**18**	20	(2)

Factors Contributing to Energy Sales Variance

Unfavourable

- Decreased production in Belize due to lower rainfall associated with a longer dry season in 2011
- Decreased production in Upper New York State due to a generating plant being out of service since May 2011

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



Factors Contributing to Revenue Variance

Unfavourable

- Decreased production in Belize

Favourable

- Higher annual average energy sales rate per megawatt hour ("MWh") in Ontario. The annual average rate per MWh was $72.96 in 2011 compared to $53.17 in 2010. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract with price indexing. Previously, energy was sold at market rates.

Factors Contributing to Earnings Variance

Unfavourable

- Decreased production in Belize
- Lower interest income at Ontario operations, associated with lower intercompany lending to regulated operations in Ontario

Favourable

- Higher annual average energy sales rate per MWh in Ontario
- Lower finance charges and higher interest income associated with operations in Belize

In May 2011 the generator at Moose River's hydroelectric generating facility in Upper New York State sustained electrical damage. Equipment and business interruption insurance claims are ongoing. Revenue for 2011 reflects the accrual of the 2011 earnings impact of the shutdown of the facility that is recoverable from the insurance claim. The generator is under repair and the facility is expected to be operational in late March 2012.

Outlook: Construction of the non-regulated Waneta Expansion in British Columbia will continue in 2012 and is expected to be completed in spring 2015.

Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2011**	2010	Variance
Hospitality Revenue	**164**	160	4
Real Estate Revenue	**67**	66	1
Total Revenue	**231**	226	5
Earnings	**23**	26	(3)

Factors Contributing to Revenue Variance

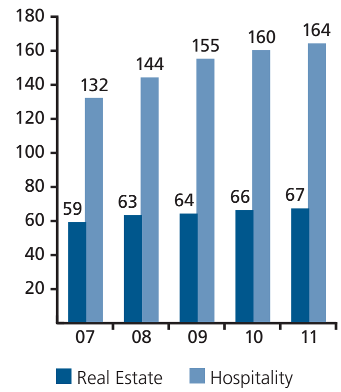
Favourable

- Revenue contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011
- A 2.1% increase in revenue per available room ("RevPar") at the Hospitality Division, excluding the impact of the Hilton Suites Winnipeg Airport hotel, to $78.48 for 2011 from $76.83 for 2010. RevPar increased due to an overall 2.7% increase in the average daily room rate, partially offset by an overall 0.6% decrease in hotel occupancy. The average daily room rate increased in all regions. Occupancy increases were achieved in Atlantic Canada and central Canada but were more than offset by occupancy decreases experienced in western Canada. Including the Hilton Suites Winnipeg Airport hotel, RevPar was $78.76 for 2011.
- Rental rate increases at the Real Estate Division

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division to 93.2% as at December 31, 2011 from 94.5% as at December 31, 2010

Fortis Properties
Revenue *($ millions)*



Factors Contributing to Earnings Variance

Unfavourable

- Higher corporate income taxes. Lower statutory income tax rates and their effect of reducing future income tax liability balances in the fourth quarter of 2010 favourably impacted corporate income taxes in 2010.
- Lower contribution from the Hospitality Division, reflecting lower performance at operations in western Canada due to decreased occupancy rates, and at operations in central Canada, partially offset by improved performance at operations in Newfoundland in Atlantic Canada, reflecting strong local economic conditions
- Higher corporate administrative expenses

Favourable

- Higher contribution from the Real Estate Division, mainly due to the $0.5 million gain on the sale of the Viking Mall in 2011

Outlook: Hotel revenue increased at Fortis Properties in 2011. Revenue is expected to grow in 2012, due in part to the addition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011.

The Real Estate Division is expected to produce stable results in 2012. 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 reduce the risk of vacancy exposure.

Corporate and Other

Financial Highlights

Years Ended December 31

($ millions)	**2011**	2010	Variance
Revenue	**29**	29	–
Operating Expenses	**10**	10	–
Amortization	**7**	7	–
Other Income (Expenses), Net	**21**	(5)	26
Finance Charges [(1)]	**71**	73	(2)
Corporate Tax Recovery	**(6)**	(16)	10
	(32)	(50)	18
Preference Share Dividends	**29**	28	1
Net Corporate and Other Expenses	**(61)**	(78)	17

[(1)] Includes dividends on preference shares classified as long-term liabilities

Factors Contributing to Net Corporate and Other Expenses Variance

Favourable

- Higher other income, net of expenses, due to: (i) a $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; and (ii) a $4.5 million foreign exchange gain associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity. The foreign exchange gain was partially offset by a $3.5 million ($3 million after-tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated debt. The favourable net impact to 2011 earnings of the above foreign exchange impacts was approximately $1.5 million. Business development costs of approximately $6 million ($4 million after tax) incurred in the first half of 2010 also had a favourable impact on other income, net of expenses, year over year.
- Lower finance charges due to the refinancing of maturing corporate debt at lower rates, the repayment of credit facility borrowings during the third quarter of 2011 with a portion of the proceeds from the common share offering in June and July 2011, and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense.

Unfavourable

- Finance charges were reduced in the fourth quarter of 2010, related to the finalization of capitalized interest on a construction project.
- Higher preference share dividends, due to the issuance of First Preference Shares, Series H in January 2010

On July 11, 2011, the Board of Directors of CVPS determined that the acquisition proposal from Gaz Métro Limited Partnership was a "Superior Proposal", as that term was defined in the Merger Agreement between Fortis and CVPS announced on May 30, 2011, and CVPS elected to terminate the Merger Agreement in accordance with its terms. Prior to such termination taking effect, the Merger Agreement provided Fortis the right to require CVPS to negotiate with Fortis for at least five business days with respect to any changes to the terms of the Merger Agreement proposed by Fortis. Fortis agreed to waive such right in exchange for the prompt payment by CVPS to Fortis of the US$17.5 million termination fee plus US$2.0 million for the reimbursement of expenses as set forth in the Merger Agreement, thereby resulting in the termination of the Merger Agreement. Fortis received the $18.8 million (US$19.5 million) payment on July 12, 2011.

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 (%) 2010	2011	2012	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	BCUC	40	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	10.00	10.00	10.00 [1]	ROEs established by the BCUC
FEWI	BCUC	40	10.00	10.00	10.00 [1]	Future Test Year
FortisBC Electric	BCUC	40	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 Future Test Year
FortisAlberta	AUC	41	9.00	8.75	8.75	COS/ROE ROE established by the AUC Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.00 +/– 50 bps	8.38 +/– 50 bps	8.38 [2] +/– 50 bps	COS/ROE The allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. The formula has been suspended for 2012. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year
FortisOntario	Ontario Energy Board ("OEB")					
	Canadian Niagara Power	40	8.01	8.01	8.01 [3]	Canadian Niagara Power – COS/ROE
	Algoma Power	40	8.57	9.85	9.85 [3]	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Franchise Agreement					
	Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2009 test year for 2010, 2011 and 2012 Algoma Power – 2007 historical test year for 2010; 2011 test year for 2011 and 2012
				ROA		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 – 9.75	7.75 – 9.75	7.75 – 9.75 [4]	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 Interim Government of the Turks and Caicos Islands ("Interim Government")	N/A	17.50 [5]	17.50 [5]	17.50 [5]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

(1) The allowed ROEs for the FortisBC Energy companies and FortisBC Electric are to be maintained, pending determinations made in the BCUC-initiated GCOC Proceeding, which will commence in March 2012.

(2) Interim, pending an expected review of Newfoundland Power's cost of capital in 2012 by the PUB

(3) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 9.42% for 2012. 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 9.42% is not applicable to Canadian Niagara Power or Algoma Power in 2012.

(4) Subject to change based on the annual operation of the RCAM to be finalized in June 2012

(5) Amount provided under licence. ROA achieved in 2010 and 2011 was significantly lower than the ROA allowed under the licence due to significant investment occurring at the utility and the lack of rate relief related thereto. In February 2012 the Interim Government approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review with the BCUC natural gas and propane commodity prices every three months and midstream costs annually, in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane and contracting for midstream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and propane and midstream costs are flowed through to customers without markup. The bundled rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balance in the Commodity Cost Reconciliation Account is recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and midstream costs. Effective January 1, 2011, FEWI's interim residential customer rates decreased by approximately 5% and FEVI's rates were unchanged. • Natural gas commodity rates were unchanged, effective April 1, 2011 and July 1, 2011, following the BCUC's quarterly reviews of commodity costs. • Effective October 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 5% to reflect changes in commodity costs, following the BCUC's quarterly review of such costs. FEWI and FEVI's rates were unchanged. • Effective January 1, 2012, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas increased by approximately 3% and rates for FEWI's residential customers increased by approximately 6%, reflecting changes in delivery and midstream costs with the rates being set on an interim basis, pending a final decision on the gas utilities' 2012–2013 Revenue Requirements Applications. Interim approval has also been received from the BCUC to hold FEVI customer rates at 2011 levels, effective January 1, 2012. Natural gas commodity rates were unchanged, effective January 1, 2012. • In December 2010 FEI filed an application with the BCUC to provide fuelling services through FEI-owned and operated compressed natural gas and LNG fuelling stations. In July 2011 FEI received a decision from the BCUC that approved the fuelling station infrastructure along with a long-term contract with one counterparty for the supply of compressed natural gas. The BCUC denied the Company's application for a general tariff for the provision of compressed natural gas and LNG for vehicles, unless certain contractual conditions are met. FEI refiled an amended application to reflect the BCUC decision and these conditions have now been approved by the BCUC. • In May 2011, in response to a complaint, the BCUC initiated a public process to develop guidelines under which FEI should be able to provide alternative energy services as regulated utility services. The alternative energy services offered by FEI include providing refuelling services for natural gas vehicles ("NGVs"), owning and operating district energy systems and various forms of geo-exchange systems, and owning facilities that upgrade raw biogas into biomethane for the purpose of selling it to customers. • In July 2011 the BCUC approved the application jointly filed by the FortisBC Energy companies and FortisBC Electric requesting the utilities be permitted to adopt US GAAP effective January 1, 2012 for regulatory reporting purposes. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to a combined 15% in the equity component of the capital structure of the new 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 facility on January 1, 2012. • In August 2011 FEI and FEVI received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for NGVs. The utilities had made these funds available to assist large customers in purchasing NGVs in lieu of diesel-fuelled vehicles. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC has requested that the companies provide further submissions to determine the prudence of the EEC incentives at a future time. • In January 2011 FEI and FEVI filed a report of a review of their Price Risk Management Plan ("PRMP") objectives with the BCUC related to their gas commodity hedging plan and FEI also submitted a revised 2011–2014 PRMP. In July 2011 the BCUC issued its decision on the report and determined that commodity hedging in the current environment was not a cost-effective means of meeting the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011–2014 PRMP with the exception of certain elements to address regional price discrepancies. As a result, FEVI and FEI have suspended commodity-hedging activities with the exception of limited swaps as permitted by the BCUC. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In September 2011 the FortisBC Energy companies filed an update to their 2012–2013 Revenue Requirements Applications. FEI has requested an increase in rates of 3.0%, effective January 1, 2012, and 3.1%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEI's application assumes forecast midyear rate base of approximately $2,760 million for 2012 and $2,820 million for 2013. FEVI has requested that rates remain unchanged for the two-year period commencing January 1, 2012. FEVI's application assumes forecast midyear rate base of $788 million for 2012 and $816 million for 2013. FEWI has requested an increase in rates of approximately 6.5%, effective January 1, 2012, and approximately 4.3%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEWI's application assumes forecast midyear rate base of $42 million for 2012 and $41 million for 2013. The requested rates reflect allowed ROEs and capital structure unchanged from 2011. The requested rate increases are driven by ongoing investment in energy infrastructure focused on system integrity and reliability, and forecast 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. A decision on the rate applications is expected in the first half of 2012. • In October 2011 FEI filed an application for approval of expenditures of approximately $5 million on facilities required to provide thermal energy services to 19 buildings in the Delta School District located in the Greater Vancouver area. When completed, FEI will own, operate and maintain the new thermal plants and charge the Delta School District a single rate for thermal energy consumed. In November 2011 FEI refiled the application with amended third-party contracts related to the thermal energy services to allow more time for a public review process. A decision on the application is expected by the end of the first quarter of 2012. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity and for the implementation of common rates and services for the utilities' customers across British Columbia, effective January 1, 2013. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia. In late 2011 the utilities temporarily suspended their application while they provide additional information to the BCUC, as requested. • In November 2011 the BCUC gave preliminary notification to public utilities subject to its regulation, including the FortisBC Energy companies and FortisBC Electric, of its intention to initiate a GCOC Proceeding early in 2012. In February 2012 the BCUC issued an order initiating the commencement of the GCOC Proceeding in March 2012. The GCOC Proceeding will take place to review: (i) the setting of the appropriate cost of capital for a benchmark low-risk utility in British Columbia; (ii) the possible return to an ROE automatic adjustment mechanism for setting an ROE for the benchmark low-risk utility; and (iii) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities in British Columbia without third-party debt. FortisBC will be involved in this regulatory process in 2012. The cost of capital review may result in a change in the utilities' capital structures and/or allowed ROEs.
FortisBC Electric	• In December 2010 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to FortisBC Electric's 2011 Revenue Requirements Application and Capital Expenditure Plan. The result was a general customer electricity rate increase of 6.6%, effective January 1, 2011. The rate increase was primarily the result of the Company's ongoing investment in energy infrastructure, including increased amortization and financing costs. • Effective June 1, 2011, the BCUC approved an increase of 1.4% in FortisBC Electric customer electricity rates arising from an increase in purchased power costs due to an increase in BC Hydro rates. • In June 2011 FortisBC Electric filed its 2012–2013 Revenue Requirements Application, which included its 2012–2013 Capital Expenditure Plan, and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. The requested rates reflect an allowed ROE and capital structure unchanged from 2011. In addition to a continuation of deferral accounts and flow-through treatments that existed under the PBR agreement, which expired at the end of 2011, the 2012–2013 Revenue Requirements Application proposes deferral accounts and flow-through treatment for variances from the forecast used to set customer rates for electricity revenue, purchased power costs and certain other costs. • In November 2011 FortisBC Electric filed an updated 2012–2013 Revenue Requirements Application to include updated financial estimates and forecasts, resulting in a revised requested increase in rates of 1.5%, effective January 1, 2012, and 6.5%, effective January 1, 2013. The revised application assumes forecast midyear rate base of approximately $1,146 million for 2012 and $1,215 million for 2013. An oral hearing process is expected to occur in March 2012 with a decision expected during 2012. • An interim, refundable customer rate increase of 1.5%, effective January 1, 2012, was approved by the BCUC pending a final decision on the Company's 2012–2013 Revenue Requirements Application.
FortisAlberta	• In December 2010 the AUC issued its decision on FortisAlberta's August 2010 Compliance Filing, which incorporated the AUC's decision, received in July 2010, on the Company's 2010 and 2011 DTA. The December 2010 decision approved the Company's distribution revenue requirements of $368 million for 2011. Final distribution electricity rates and rate riders were also approved, effective January 1, 2011.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2011 the AUC issued its decision regarding the prudence of additional capital expenditures above $104 million related to the Company's Automated Metering Project. In its decision, the AUC concluded that the full amount of the forecasted total project cost of $126 million could be included in rate base and collected in customer rates. The impact of the decision was the recognition of $3.5 million in accrued revenue in 2011 and an associated regulatory asset as at December 31, 2011. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC requesting that, effective January 1, 2012, CAREA be entitled to service 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 CAREA service area only to those customers in that service area who are not being provided service by CAREA. FortisAlberta has intervened in the proceeding to oppose CAREA's request. A decision on this matter is expected in 2012. • In 2010 the AUC initiated a process to reform utility rate regulation for distribution utilities in Alberta. The AUC intends to introduce PBR-based distribution service rates beginning in 2013 for a five-year term, with 2012 to be used as the base year. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter is expected to commence in April 2012 with a decision expected in 2012. • In March 2011 FortisAlberta filed its 2012 and 2013 DTA. The AUC allowed FortisAlberta, at the Company's request, to settle the DTA through negotiation, but stipulated that the negotiation apply only to 2012 rates in light of the AUC's target of commencing PBR-based rate setting in 2013. In November 2011 FortisAlberta filed an NSA pertaining to 2012 customer distribution rates. The NSA proposes an average rate increase of approximately 5% effective January 1, 2012. FortisAlberta's midyear rate base is currently forecast at $2.0 billion for 2012 and $2.3 billion for 2013. The requested rate increase is driven primarily by ongoing investment in energy infrastructure, including increased amortization and financing costs. In December 2011 the AUC approved an interim average rate increase of approximately 5%, effective January 1, 2012, reflecting the parameters of the NSA. The Company has also requested that volume variances be included in FortisAlberta's AESO charges deferral account for 2012, consistent with the deferral structure that was in place in 2011. A decision on the NSA is expected in the first half of 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, on an interim basis, at 8.75% for 2013. The equity component of FortisAlberta's capital structure remains at 41% and will continue at that level until changed by any future order of the AUC. The AUC concluded that it would not return to a formula-based ROE automatic adjustment mechanism at this time and that it would initiate a proceeding in due course to establish a final allowed ROE for 2013 and revisit the matter of a return to a formula-based approach in future periods. FortisAlberta and other distribution utilities in Alberta filed motions for leave to appeal with the Alberta Court of Appeal with respect to the cost of capital decision, challenging certain pronouncements made by the AUC as being incorrectly made regarding cost responsibility for stranded assets. In February 2012 FortisAlberta and other utilities filed requests for the AUC to review and vary its pronouncements.
Newfoundland Power	• In December 2010 the PUB approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset balance of approximately $53 million, associated with adoption of accrual accounting, over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the PUB for rate-setting purposes. • In December 2010 Newfoundland Power received approval from the PUB for an overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly resulting from the PUB's approval for the Company to change its accounting for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011. • On January 1, 2011, new support structure arrangements with Bell Aliant went into effect, including Bell Aliant repurchasing 40% of all joint-use poles and related infrastructure from Newfoundland Power, representing approximately 5% of Newfoundland Power's rate base. In 2001 Newfoundland Power purchased Bell Aliant's (formerly Aliant Telecom Inc.) joint-use poles and related infrastructure under a 10-year Joint-Use Facilities Partnership Agreement ("JUFPA"), which expired on December 31, 2010. Bell Aliant had rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term of the JUFPA. Bell Aliant exercised the option to buy back these poles from Newfoundland Power in 2010. The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of the joint-use poles. The PUB issued an order approving the sale of the joint-use poles in September 2011. Effective January 1, 2011, Newfoundland Power no longer received pole rental revenue from Bell Aliant. Newfoundland Power was responsible for the construction and maintenance of Bell Aliant's support structure requirements in 2011. The new support structure arrangements had no material impact on Newfoundland Power's ability to earn a reasonable return on its rate base in 2011. Proceeds of approximately $46 million from the sale of 40% of the joint-use poles were received by Newfoundland Power from Bell Aliant in October 2011. The sale proceeds were used to pay down credit facility borrowings and pay a special dividend of approximately $30 million to Fortis in order to maintain Newfoundland Power's capital structure at 45% common equity. In January 2012 the transaction with Bell Aliant closed and a purchase price adjustment of approximately $1 million was paid to Bell Aliant by Newfoundland Power. The purchase price adjustment was based on the results of a pole survey completed in the fourth quarter of 2011. • In October 2011 the PUB approved Newfoundland Power's application requesting the deferral of expected increased costs of $2.4 million in 2012, due to expiring regulatory amortizations.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• In December 2011 the PUB approved Newfoundland Power's application requesting the adoption of US GAAP, effective January 1, 2012, for regulatory reporting purposes. • In December 2011 the PUB approved, as filed, Newfoundland Power's 2012 Capital Expenditure Plan totalling approximately $77 million. • In November 2011 Newfoundland Power's allowed ROE for 2012 was calculated at 7.85% under the ROE automatic adjustment formula, a decrease from 8.38% for 2011. In December 2011 the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 and to review cost of capital for 2012. As a result, current customer rates and the allowed ROE of 8.38% will continue in effect for 2012 on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012. • Newfoundland Power's midyear rate base for 2012 is forecast at $879 million. • The Company is currently assessing the requirement for it to file a general rate application with the PUB to recover increased costs in 2013.
Maritime Electric	• In November 2010 Maritime Electric signed the Accord with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by IRAC, incremental replacement energy costs totalling approximately $47 million incurred by Maritime Electric during the refurbishment of Point Lepreau up to the end of February 2011 were deferred. The deferred costs are included in rate base. For further information on Maritime Electric's contractual obligations with respect to Point Lepreau, refer to the "Contractual Obligations" section of this MD&A. • The nature and timing of the recovery of the deferred costs related to Point Lepreau is to be determined by the PEI Energy Commission (the "PEI Commission"), which was established by the Government of PEI in 2011. Having authority under the *Public Inquiries Act*, the co-chaired five-member PEI Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, among other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year PPA between Maritime Electric and NB Power, customer electricity rates decreased overall by approximately 14%, effective March 1, 2011, reflecting a decrease in the Energy Cost Adjustment Mechanism ("ECAM") and base component of rates. A two-year customer rate freeze commenced after the March 1, 2011 rate adjustment. The allowed ROE for 2011 and 2012 is 9.75%, as set under the terms of the Accord. • Maritime Electric intends to file an application with IRAC in fall 2012 for 2013 customer rates and allowed ROE.
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 March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflected an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an average customer's electricity bill, including rate riders and other charges, was an overall increase of 3.8%. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program. Algoma Power consulted with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. The balance of Algoma Power's revenue requirement is recovered from the RRRP Program. In September 2011 Algoma Power filed its first Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The Third-Generation IRM maintains the allowed ROE at 9.85%. Algoma Power has proposed that both electricity rates and funding under the RRRP Program be indexed through a price-cap formula. In December 2011 the OEB approved current customer rates as interim rates for 2012 for Algoma Power, pending a final decision on Algoma Power's rate application. In its March 2012 rate decision, the OEB 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 has been set at approximately $11 million. • 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 current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase is subject to OEB approval.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In November 2011 the OEB published the applicable inflationary factor of 1.7% for Third-Generation IRM rate applications having a January 1, 2012 effective date. • In November 2011 FortisOntario filed a Third-Generation IRM application for rates effective May 1, 2012 for its operations in Port Colborne and a similar, but harmonized, rate application for its operations in Fort Erie and Gananoque, effective May 1, 2012. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. • FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario. • In November 2011 the OEB published the allowed ROE of 9.42% for 2012, as calculated under the ROE automatic adjustment mechanism. This allowed ROE is not applicable to regulated electric utilities in Ontario until they are scheduled to file full COS rate applications. As a result, this allowed ROE will not be applicable to FortisOntario's utilities in 2012.
Caribbean Utilities	• In March 2011 Caribbean Utilities confirmed to the ERA that the RCAM, as provided in the Company's transmission and distribution licence, yielded no customer rate adjustment effective June 1, 2011. • In March 2011 the ERA approved a Fuel Price Volatility Management Program for the utility. The objective of the program is to reduce the impact of volatility in the fuel cost charge paid by customers of Caribbean Utilities for the fuel that it must purchase in order to provide electric service. The program utilizes call options, creating a ceiling price for fuel costs at predetermined contract premiums. The program currently covers 40% of expected fuel consumption. • In July 2011 the ERA approved Caribbean Utilities' request to use US GAAP for regulatory reporting purposes, effective January 1, 2012. • In March 2011 the ERA approved $134 million of proposed non-generation installation expenditures in Caribbean Utilities' 2011–2015 Capital Investment Plan ("CIP"). The remaining $85 million of the CIP related to new generation installation, which would be subject to a competitive solicitation process. • In November 2011 CUC issued a Certificate of Need to the ERA for 18 MW of new generating capacity to be installed in 2014 and for an additional 18 MW of generating capacity to be installed in either 2015 or 2016, contingent on load growth over the next two years. The primary driver for the new generating capacity in 2014 is the upcoming scheduled retirements of several of Caribbean Utilities' generating units, which are reaching the end of their useful lives. As a result of the Company expressing its need for replacement capacity, the ERA will be conducting a competitive solicitation process in 2012 in accordance with Caribbean Utilities' licences, which will allow all interested and qualified parties, including Caribbean Utilities, to submit bids to fill the Company's firm capacity requirement. • In December 2011 Caribbean Utilities filed its 2012–2016 CIP totalling approximately US$192 million, including generation capital expenditures. The 2012–2016 CIP has been prepared in line with the Certificate of Need that was filed with the ERA in November 2011, as discussed above. A decision on the CIP is expected during the first quarter of 2012. • In December 2011 Caribbean Utilities conducted and completed a competitive bidding process to fill 13 MW of non-firm renewable energy capacity. There are currently no viable renewable energy sources on Grand Cayman that meet Caribbean Utilities' reliability requirements for firm capacity; however, Caribbean Utilities expects that there are third parties that can build and maintain renewable energy plants on Grand Cayman and sell energy to Caribbean Utilities at a price competitive with diesel. Any resulting PPAs, however, are subject to ERA review and approval.
Fortis Turks and Caicos	• In August 2011 Fortis Turks and Caicos filed with the Interim Government an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. After a series of negotiations, in February 2012, the Interim Government approved a 26% increase in electricity rates for large hotels, effective April 1, 2012. A two-step approach to standardize rates across the service territory was also approved. 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 ("kWh") consumption thresholds on both medium and large hotels; and (iii) an expansion of service territory. • 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. The purpose of the review was to: (i) assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency; (ii) assess the current and proposed electricity costs and tariffs in the Turks and Caicos Islands in relation to comparable regional and international utilities; (iii) make recommendations for a revised regulatory framework and *Electricity Ordinance*; and (iv) make recommendations for the implementation and operation of the revised regulatory framework. Fortis Turks and Caicos 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, Fortis Turks and Caicos would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. • Earlier in 2011 the Interim Government publicly stated its intention to implement a carbon tax, effective September 2011, that would be applicable to Fortis Turks and Caicos but which may not be permitted to be passed on to Fortis Turks and Caicos' customers. To date, no carbon tax has been implemented. Under the terms of an agreement with the Government of the Turks and Caicos Islands when Fortis Turks and Caicos was granted its licence, the Company is exempt from any taxes other than customs duties where applicable by law. • In March 2012 Fortis Turks and Caicos submitted its 2011 annual regulatory filing outlining the Company's performance in 2011. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$166 million for 2011 and cumulative shortfall in achieving allowable profits of US$72 million as at December 31, 2011.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2011 and December 31, 2010.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2011 and December 31, 2010

Balance Sheet Account	Increase/ (Decrease) ($ millions)	Explanation
Regulatory assets – current and long-term	100	The increase was mainly due to an increase in the deferral of: (i) future income taxes; (ii) AESO charges and deferred operating overhead costs at FortisAlberta; and (iii) various costs at the FortisBC Energy companies, as permitted by the regulator. The above increases were partially offset by a decrease in the 2010 accrued distribution revenue adjustment rider at FortisAlberta as it was collected in 2011 rates, and the deferral at the FortisBC Energy companies associated with the change in the fair market value of the natural gas derivatives.
Inventories	(34)	The decrease was driven by the impact of a decrease in gas in storage and lower natural gas commodity prices at the FortisBC Energy companies.
Assets held for sale	(45)	The decrease was due to the sale of Newfoundland Power's joint-use poles to Bell Aliant in October 2011.
Other assets	102	The increase was due to the discontinuance of the consolidation method of accounting for Belize Electricity in June 2011, due to the expropriation of the Company by the GOB, and the resulting classification of the book value of the Corporation's previous investment in Belize Electricity, including reclassified unrealized net foreign currency translation losses of $17 million, to long-term other assets.
Utility capital assets	502	The increase primarily related to $1,086 million invested in electricity and gas systems and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets, partially offset by amortization and customer contributions during 2011, and the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.
Income producing properties	34	The increase primarily related to $30 million in capital expenditures and the acquisition of the Hilton Suites Winnipeg Airport hotel in October 2011 for approximately $25 million, partially offset by amortization costs for 2011.
Intangible assets	17	The increase primarily related to $58 million in capital expenditures, partially offset by amortization costs for 2011.
Short-term borrowings	(199)	The decrease reflected the repayment of short-term borrowings at FEI, Maritime Electric and Caribbean Utilities using proceeds from the issuance of long-term debt and at FEVI using proceeds from an equity injection from Fortis.
Accounts payable and accrued charges	(39)	The decrease was mainly due to: (i) a $49 million deferred payment made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002; (ii) the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (iii) lower amounts owing for purchased natural gas at the FortisBC Energy companies due to lower volumes; and (iv) the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011. The above decreases were partially offset by higher payables associated with transmission-connected projects and cost accruals at FortisAlberta and higher accounts payable at the Waneta Partnership associated with the Waneta Expansion.
Regulatory liabilities – current and long-term	74	The increase was mainly due to: (i) increased deferrals at the FortisBC Energy companies; (ii) an increase in the ECAM account at Maritime Electric; and (iii) an increase in the provision for asset removal and site restoration costs at FortisAlberta. The increased deferrals at the FortisBC Energy companies were driven by the Rate Stabilization Deferral Account at FEVI, reflecting amounts collected in customer rates in excess of the cost of providing service during 2011, and the Revenue Stabilization Adjustment Mechanism at FEI, reflecting the margin impact of natural gas volumes consumed by residential and commercial customers in 2011 being in excess of forecast gas volumes. The above increases were partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.
Future income tax liabilities – current and long-term	55	The increase was driven by tax timing differences related mainly to capital expenditures at the FortisBC Energy companies, FortisAlberta and FortisBC Electric.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2011 and December 31, 2010 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion)	120	The increase was driven by long-term debt issued in 2011 and the impact of foreign exchange on the translation of foreign currency-denominated debt. The issuance of long-term debt was comprised of a $125 million debenture offering by FortisAlberta, a $100 million debenture offering by FEI, a $52 million note offering by FortisOntario, a $30 million bond offering by Maritime Electric and a US$40 million note offering by Caribbean Utilities. The above increases were partially offset by the repayment of the Corporation's committed credit facility borrowings with a portion of the proceeds from a $341 million common equity offering, the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011, the conversion of the Corporation's US$40 million unsecured convertible debentures into common equity and regularly scheduled debt repayments.
Shareholders' equity	572	The increase was driven by the public issuance of $341 million in common equity in June and July 2011. The remainder of the increase in shareholders' equity was primarily due to: (i) net earnings attributable to common equity shareholders during 2011, less common share dividends; (ii) the issuance of common shares under the Corporation's dividend reinvestment and stock option plans; (iii) the conversion of the Corporation's US$40 million unsecured convertible debentures into common equity; and (iv) the reclassification of $17 million of unrealized net foreign currency translation losses related to the Corporation's previous investment in Belize Electricity from accumulated other comprehensive loss to long-term other assets.
Non-controlling interests	46	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership, partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2011 compared to 2010, followed by a discussion of the nature of the variances in cash flows year over year.

Summary of Consolidated Cash Flows

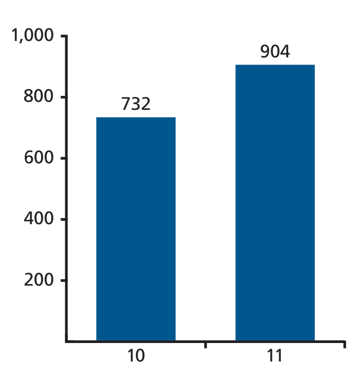
Years Ended December 31

($ millions)	**2011**	2010	Variance
Cash, Beginning of Year	**109**	85	24
Cash Provided by (Used in):			
Operating Activities	**904**	732	172
Investing Activities	**(1,125)**	(991)	(134)
Financing Activities	**201**	283	(82)
Cash, End of Year	**89**	109	(20)

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2011 was $172 million higher than in 2010. The increase was driven by favourable changes in working capital and higher earnings. The favourable working capital changes, associated primarily with accounts payable, accounts receivable and inventories, were driven by the FortisBC Energy companies and FortisAlberta.

Investing Activities: Cash used in investing activities in 2011 was $134 million higher than in 2010. The increase was due to higher gross capital expenditures and a $49 million deferred payment being made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002. The deferred payment was originally classified in long-term other liabilities. Cash used in investing activities also increased as a result of the acquisition of the Hilton Suites Winnipeg Airport hotel in 2011. The above increases were partially offset by higher proceeds from the sale of utility capital assets associated with the sale of joint-use poles at Newfoundland Power in October 2011.

Cash Flow from Operating Activities
($ millions)



Gross capital expenditures in 2011 were $1,174 million, $101 million higher than in 2010. The increase was primarily due to higher capital spending related to the non-regulated Waneta Expansion and higher capital spending at FortisAlberta, partially offset by lower capital spending at FortisBC Electric.

Financing Activities: Cash provided by financing activities in 2011 was $82 million lower than in 2010. The decrease was due to: (i) lower proceeds from the issuance of preference shares; (ii) lower proceeds from long-term debt; (iii) higher repayments of short-term borrowings; (iv) higher repayments of committed credit facility borrowings classified as long term; and (v) higher common share dividends, partially offset by: (i) higher proceeds from the issuance of common shares; (ii) lower repayments of long-term debt; and (iii) higher advances from non-controlling interests in the Waneta Partnership.

Net repayment of short-term borrowings was $198 million in 2011 compared to $56 million for 2010. The increase in the repayment 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 obligations, and net borrowings (repayments) under committed credit facilities for 2011 compared to 2010 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2011**	2010	Variance
FortisBC Energy Companies	**100** (1)	100 (2)	–
FortisAlberta	**123** (3)	124 (4)	(1)
FortisBC Electric	**–**	99 (5)	(99)
Maritime Electric	**30** (6)	–	30
FortisOntario	**52** (7)	–	52
Caribbean Utilities	**38** (8)	–	38
Corporate	**–**	200 (9)	(200)
Total	**343**	523	(180)

(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 December 2010, 30-year $100 million 5.20% unsecured debentures by FEVI. The net proceeds were used to repay credit facility borrowings.

(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 October 2010, 40-year $125 million 4.80% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(5) Issued December 2010, 40-year $100 million 5.00% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings, finance capital expenditures and for general corporate purposes.

(6) 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.

(7) 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.

(8) 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.

(9) Issued December 2010, 10-year US$125 million 3.53% and 30-year US$75 million 5.26% unsecured notes. The net proceeds were used to repay indebtedness outstanding under the Corporation's committed credit facility related to amounts borrowed to repay the Corporation's $100 million 7.4% senior unsecured debentures that matured in October 2010, and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	**2011**	2010	Variance
Newfoundland Power	**(5)**	(5)	–
Maritime Electric	**–**	(15)	15
Caribbean Utilities	**(15)**	(15)	–
Fortis Properties	**(8)**	(59)	51
Corporate	**–**	(225) (1)	225
Other	**(8)**	(10)	2
Total	**(36)**	(329)	293

(1) In April 2010 FHI redeemed in full for cash its $125 million 8% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility. In October 2010 Fortis repaid its maturing $100 million 7.4% unsecured debentures with proceeds from borrowings under the Corporation's committed credit facility.

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31

($ millions)	2011	2010	Variance
FortisAlberta	6	1	5
FortisBC Electric	9	(35)	44
Newfoundland Power	5	1	4
Corporate	(165)	41	(206)
Total	**(145)**	8	(153)

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 $84 million for 2011 and $44 million for 2010 were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion.

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of approximately $300 million. In July 2011 an additional 1.2 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 used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion, in support of infrastructure investment, and for general corporate purposes.

Fortis also received proceeds of $18 million in 2011 and $22 million in 2011, net of dividends reinvested into common shares, related to common shares issued under its stock option and share purchase plans.

In January 2010 Fortis completed a $250 million public offering of 10 million First Preference Shares, Series H. The net proceeds of approximately $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into FEI.

Common share dividends paid in 2011 totalled $151 million, net of $59 million in dividends reinvested, compared to $135 million, net of $58 million in dividends reinvested, paid in 2010. 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 $1.16 in 2011 compared to $1.12 in 2010. The weighted average number of common shares outstanding was 181.6 million for 2011 compared to 172.9 million for 2010.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties over the next five years and for periods thereafter, as at December 31, 2011, are outlined in the following table.

Contractual Obligations

As at December 31, 2011

($ millions)	Total	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt (1)	**5,788**	103	791	440	4,454
Waneta Partnership promissory note (2)	**72**	–	–	–	72
Brilliant Terminal Station ("BTS") (3)	**87**	3	6	6	72
Gas purchase contract obligations (4)	**300**	180	120	–	–
Power purchase obligations					
FortisBC Electric (5)	**2,430**	47	85	81	2,217
FortisOntario (6)	**413**	48	99	103	163
Maritime Electric (7)	**190**	50	78	48	14
Capital cost (8)	**461**	17	36	36	372
Joint-use asset and shared service agreements (9)	**64**	3	8	7	46
Office lease – FortisBC Electric (10)	**17**	2	4	2	9
Operating lease obligations (11)	**152**	26	33	32	61
Defined benefit pension funding contributions (12)	**58**	26	28	2	2
Other (13)	**22**	3	8	7	4
Total	**10,054**	508	1,296	764	7,486

(1) In prior years, FEVI received non-interest bearing repayable loans from the federal government and 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 loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates. As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the contractual obligations table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

(2) 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.

(3) On July 15, 2003, FortisBC Electric began operating the BTS under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC Electric will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

(4) Gas purchase contract obligations relate to various gas purchase contracts at the FortisBC Energy companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2011.

(5) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. 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. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases 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. Additionally, in November 2011, FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "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 estimated 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. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount 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.

(6) 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 energy and capacity and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(7) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In November 2010 the Company signed a new five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The new contract includes fixed pricing for the entire five-year period and covers, among other things, replacement energy and capacity for Point Lepreau. 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.

(8) 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, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of the agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 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. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

(10) On September 29, 1993, FortisBC Electric began leasing an office building in Trail, British Columbia for a term of 30 years. The terms of the agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

(11) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases. They also include the operating lease obligations, up to April 2012, associated with the electricity distribution assets of Port Colborne Hydro and $7 million for the exercised election under the operating lease agreement to purchase the remaining assets of Port Colborne Hydro in April 2012.

(12) 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, 2011 – Newfoundland Power
December 31, 2012 – FortisBC Energy companies (covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (covering unionized employees)
December 31, 2013 – FortisBC Electric

(13) Other contractual obligations primarily include capital lease obligations, building operating leases, AROs and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

Other Contractual Obligations: 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 gross consolidated capital program of the Corporation, including capital spending at the non-regulated operations, is forecast to be approximately $1.3 billion for 2012, which is not included in the Contractual Obligations table above.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos 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.

Capital Structure

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow 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 the utilities' customer rates.

The consolidated capital structure of Fortis as at December 31, 2011 compared to December 31, 2010 is presented in the following table.

Capital Structure	**2011**		2010	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**5,855**	**55.0**	5,914	58.4
Preference shares [(2)]	**912**	**8.6**	912	9.0
Common shareholders' equity	**3,877**	**36.4**	3,305	32.6
Total [(3)]	**10,644**	**100.0**	10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Includes preference shares classified as both long-term liabilities and equity
(3) Excludes amounts related to non-controlling interests

The improvement in the capital structure was driven by the public offering of approximately $341 million of common shares in June and July 2011, combined with common shares issued under the Corporation's dividend reinvestment and stock option plans, the conversion of US$40 million of debentures into common equity and the reclassification of net unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity to long-term other assets. Also contributing to the improvement was net earnings attributable to common equity shareholders, net of dividends, combined with an overall decrease in total debt. A portion of the proceeds from the public common equity offering were used to repay credit facility borrowings in 2011.

Credit Ratings

As at December 31, 2011, the Corporation's credit ratings were as follows:

S&P	A– (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

The above credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, 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. During the third quarter of 2011, DBRS confirmed the Corporation's existing debt credit rating at A(low). S&P is expected to complete its annual review of the Corporation's debt credit rating in the first quarter of 2012. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P placed the Corporation's credit rating on credit watch with negative implications. For further information, refer to the "Subsequent Event" section of this MD&A.

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 $98 million in maintenance and repairs was expensed in 2011 compared to approximately $96 million in 2010.

Gross consolidated capital expenditures for 2011 were approximately $1.2 billion. A breakdown of gross consolidated capital expenditures by segment and asset category for 2011 is provided in the following table.

Gross Consolidated Capital Expenditures [(1)]

Year Ended December 31, 2011

($ millions)	FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility [(3)]**	**Fortis Properties**	**Total**
Generation	–	–	18	10	2	**30**	**32**	**172**	**–**	**234**
Transmission	73	–	26	6	3	**108**	**1**	**–**	**–**	**109**
Distribution	103	279	26	56	38	**502**	**26**	**–**	**–**	**528**
Facilities, equipment, vehicles and other	61	122	27	4	1	**215**	**11**	**2**	**30**	**258**
Information technology	16	15	5	5	3	**44**	**1**	**–**	**–**	**45**
Total	253	416	102	81	47	**899**	**71**	**174**	**30**	**1,174**

(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. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures were permissible in rate base in 2011.

(2) Includes payments made to AESO for investment in transmission-related capital projects

(3) Includes non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures

Gross consolidated capital expenditures of $1,174 million for 2011 were $38 million lower than $1,212 million forecast for 2011, as disclosed in the MD&A for the year ended December 31, 2010. 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 the timing of certain capital expenditures from 2011 to 2012 and various small capital projects determined to be not required at the FortisBC Energy companies; (ii) the discontinuance of the consolidation method of accounting for Belize Electricity, effective June 2011; and (iii) a shift in capital expenditures from 2011 to 2012 related to the timing of payments associated with the Waneta Expansion.

Gross consolidated capital expenditures for 2012 are expected to be approximately $1.3 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2012 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [(1)]

Year Ending December 31, 2012

($ millions)	FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility [(3)]**	**Fortis Properties**	**Total**
Generation	–	–	10	12	3	**25**	**21**	**255**	**–**	**301**
Transmission	68	–	38	6	9	**121**	**1**	**–**	**–**	**122**
Distribution	110	252	34	55	43	**494**	**25**	**–**	**–**	**519**
Facilities, equipment, vehicles and other	46	149	23	5	3	**226**	**6**	**1**	**63**	**296**
Information technology	20	18	6	4	3	**51**	**2**	**–**	**–**	**53**
Total	244	419	111	82	61	**917**	**55**	**256**	**63**	**1,291**

(1) Relates to forecast cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012.

(2) Includes forecast payments to be made to AESO for investment in transmission-related capital projects

(3) Includes forecast non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures

The percentage breakdown of 2011 actual and 2012 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows:

Gross Consolidated Capital Expenditures

Year Ending December 31 (%)	**Actual 2011**	Forecast 2012
Growth	**44**	40
Sustaining [(1)]	**30**	33
Other [(2)]	**26**	27
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 and the Customer Care Enhancement Project at FEI.

Significant capital projects for 2011 and 2012 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) Company	Nature of project	Pre-2011	**Actual 2011**	Forecast 2012	Forecast Post-2012	Expected Year of Completion
FortisBC Energy Companies	LNG storage facility – Vancouver Island	176	**34**	2 [(2)]	–	2011
	Customer Care Enhancement Project	29	**51**	30	–	2012
	Fraser River South Bank South Arm Rehabilitation Project	21	**11**	4 [(2)]	–	2011
FortisAlberta	Automated Metering Project	112	**11**	3 [(2)]	–	2011
	Pole Management Program	60	**28**	27	220	2019
FortisBC Electric	Okanagan Transmission Reinforcement Project	86	**14**	5 [(2)]	–	2011
	Generation Asset Upgrade and Life-Extension Program	17	**15**	3	–	2012
	Environmental Compliance Project	–	**2**	11	15	2014
Fortis Turks and Caicos	Three new 9-MW diesel-powered generating units	15	**6**	–	8	2014
Waneta Partnership	Waneta Expansion [(3)]	75	**169**	254	359	2015
Fortis Properties	Office Building – St. John's	–	**8**	32	7	2013

(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) Project costs to be incurred in 2012 subsequent to the 2011 in-service date.

(3) Excludes forecast capitalized interest of the Corporation's partners, CPC/CBT, in the Waneta Partnership

FEVI's construction of the estimated $212 million 1.5 billion-cubic foot LNG storage facility at Mount Hayes on Vancouver Island was completed in the second quarter of 2011 and was brought online in late 2011. The storage facility provides a reliable, cost-competitive means of storing gas close to customers while reducing dependence on out-of-province storage facilities. The facility provides greater flexibility to meet customer needs during winter months when demand for natural gas is at its highest and to meet planned and unplanned system interruptions.

FEI's Customer Care Enhancement Project, at an estimated total project cost of $110 million, came into service in January 2012. The Company estimates approximately $30 million of the project cost to be incurred in the first half of 2012 related to final contractor payments, with the total project cost expected to come in under budget. 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. The BCUC approved the project upon the Company's acceptance of a cost risk-sharing condition, whereby FEI agreed to equally share with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost.

The Fraser River South Bank South Arm Rehabilitation Project involved the installation and replacement of underwater transmission pipeline crossings that were at potential risk of failure from a major seismic event. During 2010 difficulties were experienced with one of the directional drills, delaying the project, which was subsequently completed and came into service in 2011, rather than in 2010 as originally expected, at an estimated total cost of approximately $36 million.

During the first quarter of 2011, FortisAlberta substantially completed its $126 million Automated Metering Project, which involved the replacement of approximately 477,000 conventional meters.

During 2011 FortisAlberta continued the replacement of vintage poles under its Pole Management Program, which involves 96,000 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 $335 million, an increase from the $283 million forecast as at December 31, 2010. The increase is primarily due to a revised forecast estimating higher labour and material costs later in the program and a change in the program scope to include minor-line rebuilds.

FortisBC Electric's $105 million Okanagan Transmission Reinforcement Project was substantially completed in fall 2011. The project related to upgrading the existing overhead transmission line between Penticton and Vaseux Lake, near Oliver, from 161 kilovolts ("kV") to a double-circuit 230-kV line and building a new 230-kV terminal substation in the Oliver area.

Since 1998 hydroelectric generating facilities at FortisBC Electric have been subject to an upgrade and life-extension program. Newly installed equipment will enhance reliability and efficiency, while the use of standardized components will reduce future maintenance and capital expenditures. Approximately $15 million was spent during 2011 with a remaining $3 million expected to be incurred in 2012 related to this initiative.

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 (SOR/2008-273)* by 2014. The project is estimated to cost approximately $28 million through to 2014. Regulatory approval was obtained for 2011 costs with the remaining project costs subject to BCUC approval.

Fortis Turks and Caicos had an agreement with a supplier to purchase two diesel-powered generating units, each with a capacity of 9 MW. The units were delivered in 2010 and 2011. Assuming demand for additional generating capacity in 2014, an additional 9-MW unit is forecast for delivery at an estimated cost of approximately $8 million (US$8 million). An agreement for the additional unit has not yet been formalized as it is dependent on future demand trends.

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. 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 include the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $244 million has been spent on the Waneta Expansion since construction began late in 2010. The Waneta Expansion will be included in the amended and restated 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, is expected to 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 forecast capitalized interest of the Corporation's partners, CPC/CBT.

In August 2011 Fortis Properties received municipal government approval to construct a $47 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature 152,000 square feet of Class A office space and include 261 parking spaces. Construction is expected to be completed in the second half of 2013.

Over the five-year period 2012 through 2016, gross consolidated capital expenditures are expected to be approximately $5.5 billion. Approximately 64% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital spending is expected to be incurred at the regulated gas utilities and non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, 39% of utility capital spending is expected to be incurred to meet customer growth; 38% is expected to be incurred to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e., sustaining capital expenditures); and 23% is expected to be incurred for facilities, equipment, vehicles, information technology and other assets.

Cash Flow Requirements

At the operating 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 flow 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 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 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 2012 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be $103 million in 2012 and to average approximately $270 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.

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 and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 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. For a further discussion of the Exploits Partnership, refer to the "Key Trends and Risks – 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, 2011 and are expected to remain compliant in 2012.

Credit Facilities

As at December 31, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.9 billion was unused, including the Corporation's unused $800 million committed credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.1 billion of the total credit facilities are committed facilities with maturities ranging from 2012 through 2015.

The cost of renewed and extended credit facilities has been increasing as a result of current economic conditions; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2012.

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

Credit Facilities

($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2011**	Total as at December 31, 2010
Total credit facilities	845	1,390	13	**2,248**	2,109
Credit facilities utilized:					
Short-term borrowings	–	(157)	(2)	**(159)**	(358)
Long-term debt (including current portion)	–	(74)	–	**(74)**	(218)
Letters of credit outstanding	(1)	(65)	–	**(66)**	(124)
Credit facilities unused	844	1,094	11	**1,949**	1,409

As at December 31, 2011 and 2010, 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, 2010 to December 31, 2011 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2011 are detailed in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

In February 2011 Maritime Electric renewed its unsecured committed revolving credit facility and reduced it from $60 million to $50 million. In February 2012 Maritime Electric renewed the credit facility for a further two years.

In April 2011 FortisBC Electric renegotiated and amended its credit facility agreement, resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility, with $100 million now maturing in May 2014 and $50 million now maturing in May 2012.

In April 2011 FHI extended the maturity date of its $30 million unsecured committed revolving credit facility to May 2012.

In June 2011 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility to August 2015 from August 2013. 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 August 2011 the Corporation renegotiated and amended its unsecured committed revolving credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the maturity date of the facility to July 2015 from May 2012. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. 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 September 2011 FortisAlberta amended its unsecured committed revolving credit facility to increase the amount available under the facility to $250 million from $200 million and extend the maturity date to September 2015 from May 2012. The amended credit facility agreement reflects an increase in pricing.

In November 2011 FEVI renegotiated and amended its unsecured committed revolving credit facility, decreasing the amount available under the facility from $300 million to $200 million and extending the maturity date of the facility to December 2013 from May 2012. 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

As at December 31, 2011, the Corporation had no off-balance sheet arrangements, with the exception of letters of credit outstanding of $66 million, 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 some form of 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.

Approximately 93% of the Corporation's operating revenue was derived from regulated utility operations in 2011 (2010 – 93%), while approximately 89% of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2011 (2010 – 87%). Regulated utility assets comprised approximately 91% of total assets of Fortis as at December 31, 2011 (December 31, 2010 – 92%). The Corporation's regulated utilities primarily operate under COS methodologies. 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 costs of providing services, 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 the utilities to recover the actual costs of providing services and to earn the approved ROEs and/or ROAs is impacted by achieving the forecasts established in the rate-setting processes. 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 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. Capital cost overruns subject to such approvals might not be recoverable in customer rates.

Through the regulatory process, the regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows the utilities 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 that reflect COS and establish revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a public hearing process. There can be no assurance that rate orders issued or negotiated settlements approved by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return or appropriate capitalization.

A failure to obtain rates or appropriate ROEs and capital structure as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of proposed capital project upgrades or expansions, ratings assigned by credit rating agencies, the issuance and sale of securities and other matters, which may, in turn, negatively affect the results of operations and financial position of the Corporation's 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.

As an owner of an electricity distribution network under the *Electric Utilities Act* (Alberta) (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 as a default supplier, and no other party is willing to act as a regulated-rate provider or as a 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.

Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced. However, stemming from the outcome of the June 2008 Final Decision of the Public Utilities Commission, regulatory challenges continued at Belize Electricity that impeded the utility's ability to earn a fair and reasonable return in 2010 and through to June 2011, at which time the utility was expropriated from Fortis by the GOB. There was no earnings contribution from Belize Electricity to the consolidated earnings of Fortis in 2011 and only $1.5 million of earnings contribution in 2010. For a further discussion of Belize Electricity, refer to the "Business Risk Management – Investment in Belize" section of this MD&A. Also, an independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed in 2011. The timing and future impact of any newly adopted regulatory framework in this jurisdiction is uncertain at this time.

The Corporation has a concentration of regulatory risk in British Columbia, with 56% of the Corporation's regulated assets under the jurisdiction of the BCUC. The risk is heightened by a significant regulatory calendar for 2012 for FortisBC's gas and electricity businesses.

FEI, FEVI, FEWI and FortisBC Electric are regulated by the BCUC and have used PBR mechanisms from time to time. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. 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. FortisBC Electric and the FortisBC Energy companies have filed full COS applications for 2012 and 2013 rates with no assumption of PBR.

The AUC intends to introduce PBR-based distribution service rates in Alberta beginning in 2013 for a five-year term, with 2012 to be used as the base year. FortisAlberta submitted its PBR proposal to the AUC in July 2011 outlining its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter is expected to commence in April 2012 with a decision on PBR expected in 2012.

As a result of the Accord, the PEI Commission was established by the Government of PEI. Having authority under the *Public Inquiries Act*, the co-chaired five-member PEI Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the PEI Commission will, among other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. The carrying out of the above goal by the PEI Commission could impact how Maritime Electric is regulated going forward as well as its future ownership.

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.

A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section below.

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. The formulaic ROE automatic adjustment mechanisms tied to long-term Canada bond rates, used in recent years at the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power, had resulted in lower allowed ROEs. A significant decline in interest rates and their impact on allowed ROEs could adversely affect the financial condition and results of operations of the Corporation's regulated utilities.

In response to the decrease in long-term interest rates, many regulators in Canada reviewed the ROE automatic adjustment mechanisms by the end of 2009 and, in many cases, removed the use of ROE automatic adjustment mechanisms. Long-term Canada bond rates continue to be low. At the Corporation's four largest utilities, only Newfoundland Power used an automatic adjustment mechanism to set the allowed ROE for 2011. In December 2011, however, the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 pending a full cost of capital review for 2012. In the interim, the allowed ROE at Newfoundland Power will remain at 8.38% for 2012. In December 2011 the AUC issued a decision on its GCOC Proceeding, resulting in a 25 basis point reduction in the generic allowed ROE to 8.75% for 2011 and 2012, and 8.75% for 2013 on an interim basis, for utilities under the jurisdiction of the AUC, including FortisAlberta. The AUC did not reinitiate an ROE automatic adjustment mechanism at this time. The BCUC has also initiated a GCOC Proceeding, which will commence in March 2012, and may impact the capital structures and/or allowed ROEs of the FortisBC Energy companies and FortisBC Electric. Uncertainty exists regarding the duration of the current environment of low interest rates and what effect this may have on allowed ROEs of the Corporation's regulated utilities.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under credit facilities and floating-rate long-term debt. At the FortisBC Energy companies and FortisBC Electric, however, interest expense variances from forecast for rate-setting purposes, related to floating-rate debt, were recovered through customer rates using regulatory deferral accounts approved by the BCUC to the end of 2011. The FortisBC Energy companies also have a deferral mechanism that captures the impact on interest expense of the differences between forecast and actual long-term interest rates and forecast and actual timing of issuance of long-term debt. There can be no assurance that the above 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 new long-term debt is raised at interest rates higher than those forecast and approved in customer rates, the additional interest costs incurred on the new long-term debt are not able to be recovered from customers in rates during the period that was covered by the approved rates.

As at December 31, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, excluding borrowings under long-term committed credit facilities, 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, 2011.

Total Debt

As at December 31, 2011	*($ millions)*	*(%)*
Short-term borrowings	**159**	**2.7**
Utilized variable-rate credit facilities classified as long-term	**74**	**1.2**
Variable-rate long-term debt and capital lease obligations (including current portion)	**2**	**–**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**5,709**	**96.1**
Total	**5,944**	**100.0**

Long-term debt was issued by the Corporation's regulated utilities in 2011 at attractive rates ranging from 4.25% to 5.118% and with terms ranging from 15 to 50 years.

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, 2011, is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates, as that change would have affected 2011 financial results, is disclosed in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

Operating and Maintenance Risks: 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. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets are damaged due to weather conditions and other acts of nature. The FortisBC utilities operate in a remote and mountainous terrain with a risk of loss or damage from forest fires, 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 or other natural disasters, application will 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 must 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 effect on the operations of the Corporation's utilities.

The Corporation's 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. The failure to do so may disrupt the ability of the utilities to safely distribute gas and electricity, which could have a material 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 effect on the utilities' financial conditions and results of operations.

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.

In the Caribbean, the level of, and fluctuations in, tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand at the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region. The Corporation's service territory in the Caribbean region continues to be impacted by challenging economic conditions. Many non-locals working in the construction industry on Grand Cayman and in the Turks and Caicos Islands have returned to their home countries or other jurisdictions, as a result of the strong reduction in construction activity due to the weak local economies. On the positive side, the recent completion and commissioning of phase one of a local airport expansion at the principal airport in Providenciales in the Turks and Caicos Islands in September 2011 should help foster future economic growth, mainly in the tourism and commercial sectors, allowing direct flights from Europe and accommodating more flights from North America. On Grand Cayman, several residential, resort and commercial projects were completed in 2011, which have the potential to increase load and electricity sales for Caribbean Utilities.

Any sustained recovery of the economy in the Caribbean region, however, will hinge on the recovery of the U.S. economy. In line with the general U.S. economic forecast, it is expected that the current local economic weakness in the Caribbean region will continue into 2012 and possibly beyond. Due to continued challenging economic conditions in the Caribbean, combined with the impact on customer bills of high fuel prices, there was no growth in electricity sales at Caribbean Utilities and Fortis Turks and Caicos for 2011. Electricity sales growth for 2012 is projected to be minimal.

Generally, higher energy prices can result in reduced consumption by customers. However, natural gas and crude oil exploration and production activities in certain of the Corporation's service territories 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.

Fortis also holds investments in both commercial office and retail space and hotel properties, with those assets 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. Fortis Properties' real estate exposure to lease expiries averages approximately 9% per annum over the next five years. Approximately 56% of Fortis Properties' operating income was derived from hotel investments in 2011 (2010 – 55%). Organic revenue and earnings growth at Fortis Properties' Hospitality Division has been low in recent years, due to challenging economic conditions and the overall impact on leisure and business travel and hotel stays. Occupancy increases, however, were achieved in 2011 at the Company's hotel operations in Atlantic Canada and central Canada, but were more than offset by occupancy decreases experienced in western Canada. It is estimated that a 10% decrease in revenue at 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.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its larger 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 results of operations and the financial position of the Corporation and the subsidiaries, 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, as well as all 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 were successful at raising long-term capital at reasonable rates. Volatility in the global financial and capital markets may have the effect of increasing the cost of, and affecting the timing of, issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of borrowing could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities generally increased in 2011; however, increased interest expense and/or fees did not materially impact the results of operations or financial condition of the Corporation and its subsidiaries in 2011 nor are they expected to in 2012. During 2011 the Corporation and FortisAlberta renegotiated their respective credit facility agreements in advance of the scheduled maturity dates, resulting in substantially similar terms as the former credit facilities, but there was an increase in pricing reflecting current general market conditions. Due to their regulated nature, increased cost of borrowing at the utilities is eligible to be recovered in customer rates.

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 $800 million committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes and may be increased to $1 billion at any time prior to maturity upon written notice by Fortis. As at December 31, 2011, Fortis had approximately $2.2 billion in consolidated credit facilities, of which $2.1 billion is committed with maturities ranging from 2012 through 2015. Approximately $1.9 billion of the credit facilities were unused as at December 31, 2011. No amounts were drawn on the corporate credit facility at as December 31, 2011.

Generally, the Corporation and its regulated utilities, which are currently rated, 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 offerings and on the Corporation's and its utilities' credit facilities. Changes in credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Also, a significant downgrade in FEI's credit ratings could trigger margin calls and other cash requirements under FEI's natural gas purchase and natural gas derivative contracts. Fortis and its utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial crisis has prompted increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

DBRS confirmed the Corporation's unsecured debt credit rating in October 2011 but, in February 2012, placed the credit rating under revew with developing implications following the CH Energy Group acquisition announcement by Fortis. S&P is expected to complete its annual review of the Corporation's debt credit rating in the first quarter of 2012 but, in February 2012, placed the credit rating under credit watch with negative implications, also due to the acquisition announcement. For further information, refer to the "Liquidity and Capital Resources – Credit Ratings" and "Subsequent Event" sections of this MD&A. During 2011 DBRS confirmed its existing credit ratings for Newfoundland Power, Caribbean Utilities, FortisBC Electric, FHI and FEI and in March 2012 confirmed FortisAlberta's existing credit rating. Also, Moody's Investors Service confirmed its existing credit ratings for Newfoundland Power, FortisAlberta and FEI, while S&P maintained its existing credit rating for Maritime Electric, but downgraded Caribbean Utilities' credit rating from A to A– due to a weak customer market and increased business risks. FortisAlberta's existing debt credit rating by S&P was confirmed in January 2012, but was put on credit watch with negative implications in February 2012 due to the Corporation's credit rating being placed on credit watch.

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 and under "Liquidity Risk" in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

Investment in Belize: In June 2011 the GOB expropriated the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The Corporation is exposed to risk associated with the timeliness and the ultimate amount that will be paid, as well as the ability of the GOB to pay the compensation owing to Fortis. The book value of the Corporation's previous investment in Belize Electricity recorded in long-term other assets on the consolidated balance sheet of Fortis as at December 31, 2011 was $106 million, including foreign exchange impacts. For further information, refer to the "Key Trends and Risks – Expropriated Assets" section of this MD&A.

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generation subsidiary in Belize. BECOL generates hydroelectricity from three plants located on the Macal River with a combined generating capacity of 51 MW. The entire output of the plants is sold to Belize Electricity under 50-year contracts expiring in 2055 and 2060. Assuming normal hydrological conditions, Belize Electricity purchases BECOL's normalized annual energy production of 240 GWh at approximately US$0.10 per kWh, which generally is the lowest-cost energy supply source in the country of Belize. As at December 31, 2011, the book value of the Corporation's investment in BECOL was $154 million. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The GOB has also indicated it has no intention to expropriate BECOL.

As at February 29, 2012, Belize Electricity owed BECOL US$7.5 million for overdue energy purchases, representing almost one-third 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.

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 rate stabilization account 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-forecast gas volumes consumed by residential and commercial customers.

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 materially impact 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 amended and restated 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 preparation for severe weather, hurricanes and other natural disasters will always remain a risk to utilities. Climate change, however, may have the impact of increasing the severity and frequency of weather-related natural disasters that 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. 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. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company 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.

Earnings from non-regulated generation assets are sensitive to rainfall levels; however, the geographic diversity of the Corporation's generation assets helps to mitigate the risk associated with rainfall levels. The Waneta Expansion will be included in the amended and restated 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 rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility. In the past, the FortisBC Energy companies employed a number of tools to reduce exposure of commodity rates charged to customers to natural gas price volatility. Prior to mid-2011, these tools included hedging strategies based on a combination of both physical and financial transactions. As ordered by the BCUC, the FortisBC Energy companies discontinued most hedging activities by mid-2011, with existing hedges being managed to expiry. The use of natural gas derivatives effectively fixes the price of natural gas purchases and any resulting gains or losses effectively accrue entirely to customers. The absence of hedging activities may cause an increase in natural gas price volatility as this affects customer rates.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk 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 sharp 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 materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial 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 commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange forward contracts, fuel option contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk and are not used or held for trading purposes. All derivative financial instruments are measured at fair value. If a derivative financial instrument is designated as a hedging item in a designated qualifying cash flow hedging relationship, the effective portion of changes in fair value is recognized in other comprehensive income. Any change in fair value relating to the ineffective portion is recognized immediately in earnings. At the FortisBC Energy companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, self-sustaining 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. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar. 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 self-sustaining foreign net investments, which are also recognized in other comprehensive income. As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining foreign net investments remaining to be hedged.

Effective from June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity, recorded in long-term other assets, does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining 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 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. As a result, the Corporation recognized a net after-tax foreign exchange gain of approximately $1.5 million in 2011.

It is estimated that a 5 cent, or 5%, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of US$1.00=CDN$1.02, as at December 31, 2011, would increase (decrease) basic earnings per common share of Fortis by 3 cents in 2012.

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 financial 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 2011 and do not expect any counterparties to fail to meet their obligations. As events in the recent past 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 credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, 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. 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, however, there is potentially significant new investment in the electricity generation and transmission sector in British Columbia, which may put upward pressure on electricity rates. Furthermore, the growth in natural gas supply, due to the productivity and cost improvements associated with shale gas production, and subsequent decline in market natural gas prices, have helped to improve natural gas competitiveness on an operating basis. However, differences in upfront capital costs between electric-heated homes and natural gas-heated homes present a challenge for the competitiveness of natural gas on a full-cost basis. Further, there are other competitive factors that are impacting the penetration of natural gas in new housing builds, such as the green attributes of the energy source, government policy and the type of housing being built. A reduction in natural gas supply, due to low market prices and increased industrial and commercial demand due to stronger economic growth, are factors that may lead to materially higher market gas prices and volatility. In the future, if natural gas pricing becomes uncompetitive with pricing for electricity and other alternative energy sources, 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. This may result in higher rates and could, in an extreme case, ultimately lead to an inability to fully recover COS of the FortisBC Energy companies 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 Vancouver, Fraser Valley and Vancouver Island service areas, where the majority of the natural gas distribution customers of the FortisBC Energy companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing 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 new LNG storage facility on Vancouver Island, however, provides short-term supply during cold weather conditions or emergency situations.

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.

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 own 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 and an executed version of the agreement was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of filing of the executed agreement.

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 maintain defined benefit pension plans for certain of their employees. Approximately 60% of the above utilities' total employees are members of such plans.

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension 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 accrued pension 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.

Pension 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 accrued pension benefit obligations as at the measurement date of each of the defined benefit pension plans, 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, the accrued benefit asset, the accrued benefit liability and the 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 the forecast 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 net pension cost deferral mechanisms that were approved by the BCUC to the end of 2011 for the FortisBC Energy companies and FortisBC Electric will continue in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through net pension costs in customer rates could materially impact the results of operations, financial position and cash flows of the regulated utilities. Also mitigating the above 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 began absorbing the full commodity cost of natural gas and all other COS. The Company has requested the continuation of the Rate Stabilization Deferral Account mechanism in its 2012–2013 Revenue Requirements Application, which allows FEVI to accumulate the recovery of costs from customers above FEVI's COS. Also, the remaining $49 million of outstanding non-interest bearing government loans, which is currently treated as a government contribution against rate base, 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, released in 2007, is a natural progression from the previous plan, with 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 amending 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. Specifically, the *Clean Energy Act* outlines 16 energy objectives for British Columbia, including the objective to have 93% of British Columbia's electricity generated from clean or renewable resources, to take demand-side measures and to conserve energy to meet a minimum of 66% of the expected increase in BC Hydro's demand for electricity by the year 2020, and to become a net exporter of electricity generated from clean or renewable resources. 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 2010 the FortisBC Energy companies began reporting and had external verification of GHG emissions generated by its facilities, as required under the *Greenhouse Gas Reduction (Cap and Trade) Act.* 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 amount.

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol was extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on 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. It is uncertain as to what impact this withdrawal 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, 2011, there were no material environmental liabilities recognized in the Corporation's 2011 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 materially affect the results of operations, cash flows 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, cash flows 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 in 2013. 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) set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge on 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 2011 direct costs arising from environmental protection, compliance, damages and carrying out 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 and customer claims that are substantial in amount and which could have an 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 from 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 materially affect 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 amended and restated 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. Government authorities in Canada and the United States have the power under the treaty 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 of its 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). 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 for compensation, including payment for FortisAlberta's assets 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. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the results of operations, cash flows and financial position of FortisAlberta.

Refer also to the "Material Regulatory Decisions and Applications – FortisAlberta" section of this MD&A for additional information with respect to the risk of loss of service area.

Transition to New Accounting Standards: 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. Securities and Exchange Commission ("SEC") Issuers pursuant to Canadian securities laws. The Corporation and its reporting issuer subsidiaries, therefore, will be adopting US GAAP as opposed to IFRS on January 1, 2012. Earnings to be recognized under US GAAP are expected to be 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 significant volatility in the Corporation's consolidated earnings.

If the exemption from the OSC does not continue past December 31, 2014, then the Corporation and its reporting issuer subsidiaries will 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 "Future Accounting Standards" section of this MD&A.

Changes in Tax Legislation: Fortis currently keeps the earnings of its Caribbean operations in offshore tax-free jurisdictions. The Government of Canada enacted legislative changes that challenge the tax-deferred status of offshore earnings. The legislative changes require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada by 2014.

If the jurisdictions are unable to establish tax treaties or TIEAs, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were earned in Canada. Conversely, if tax treaties or TIEAs are reached, the earnings from these jurisdictions can be repatriated to Canada tax-free.

The Government of Canada announced the entry into TIEAs with the Cayman Islands and Bermuda on June 1, 2011 and July 1, 2011, respectively, and with the Turks and Caicos Islands on October 6, 2011. Fortis expects that a TIEA with Belize will be in place by the 2014 deadline.

The income tax regulations 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 that 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 multinationals. 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 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, 2011, the Corporation had approximately $68 million of upstream loans that will now have to be repaid before December 31, 2013, at which time any outstanding balance will be included in the Corporation's taxable income. The Corporation also had approximately $18 million in downstream loans, as at December 31, 2011, that can be used to offset the impacts of having to repay the upstream loans.

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, 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 allowing the Corporation to comply with the above legislative proposals.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

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; provide customers with billing, consumption and load settlement information; and support the financial and general operating aspects of their business. 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' reserves and maintain gas distribution facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations bands. A treaty negotiation process involving various First Nations bands and the Government of British Columbia 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 bands 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 materially affect the businesses of the FortisBC Energy companies and FortisBC Electric.

Furthermore, the Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals, the BCUC must consider whether the Crown has a duty to consult First Nations and to accommodate First Nations regarding the impact of such approvals and, if so, whether Crown consultation and accommodation have been adequate. The above 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 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 effect on the business of 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 effect on the results of operations, cash flows and financial position of the utilities.

In December 2010 FortisAlberta reached a three-year collective agreement with the United Utility Workers' Association of Canada, Local 200.

The collective agreement between FortisBC Electric and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired January 31, 2011. During 2011 discussions between the Company and COPE focused on renegotiation of the COPE agreement. An agreement has been reached with regard to certain customer service employees. Discussions continue with regard to the remaining COPE bargaining unit.

The collective agreement between FortisBC Electric and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expires on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D.

The collective agreement between the FortisBC Energy companies and IBEW, Local 213, expired March 31, 2011 and is currently being negotiated. The collective agreement between the FortisBC Energy companies and COPE, Local 378, expires on March 31, 2012.

The two collective agreements between Newfoundland Power and IBEW, Local 1620, expired in September 2011. The Company and IBEW reached a tentative agreement in January 2012, which is subject to ratification by the members.

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 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.

FUTURE ACCOUNTING CHANGES

Adoption of New Accounting Standards: Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board, Fortis has evaluated the option of adopting US GAAP, as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to file its financial statements prepared in accordance with US GAAP by qualifying as an SEC Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the OSC seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently refers to US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

During the fourth quarter of 2010, the Corporation developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

Phase I – Scoping and Diagnostics: Phase I consisted of project initiation and awareness, project planning and resourcing, and identification of high-level differences between US GAAP and Canadian GAAP in order to highlight areas where detailed analysis would be needed to determine and conclude as to the nature and extent of financial statement impacts. External accounting and legal advisors were engaged during this phase to assist the Corporation's internal US GAAP conversion team and to provide technical input and expertise as required. Phase I commenced in the fourth quarter of 2010 and was completed during 2011.

Phase II – Analysis and Development: Phase II consisted of detailed diagnostics and evaluation of the financial statement impacts of adopting US GAAP based on the high-level assessment conducted under Phase I; identification and design of any new, or changes to, operational or financial business processes; initial staff training and audit committee orientation; and development of required solutions to address identified issues.

Phase II had included planned activities for the registration of securities as required to achieve SEC Issuer status and an assessment of ongoing requirements of the United States *Sarbanes-Oxley Act* ("US SOX"), including auditor attestation of internal controls over financial reporting, and a comparison of the requirements under US SOX to those required in Canada under National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*. These activities were no longer required or applicable as a result of the Exemption granted by the OSC as discussed above.

Phase II of the plan commenced in January 2011 and was essentially completed during 2011. Based on the research and analysis completed to date, and the Corporation's continued ability to apply rate-regulated accounting policies under US GAAP, the differences between US GAAP and Canadian GAAP are not expected to have a material impact on consolidated earnings. In addition, adoption of US GAAP is expected to result in limited changes in balance sheet classifications and result in additional disclosure requirements. The impact on information systems and internal controls over financial reporting is expected to be minimal.

Phase III – Implementation and Review: Phase III is currently ongoing and has involved the implementation of financial reporting systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements in accordance with US GAAP beginning in 2012, and the communication of associated impacts.

The Corporation has prepared and filed its audited Canadian GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives, in the usual manner. The Corporation has also voluntarily prepared and filed audited US GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP and filed.

Phase III will conclude when the Corporation files its annual audited consolidated financial statements for the year ending December 31, 2012 prepared in accordance with US GAAP.

Financial Statement Impacts – US GAAP: The areas identified where differences between US GAAP and Canadian GAAP have the most significant financial statement impacts are outlined below.

Employee future benefits: Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit plans is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded status being disclosed in the notes to the consolidated financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains and losses and transitional obligations, which have not yet been recognized.

US GAAP requires recognition of the funded status of defined benefit plans on the balance sheet. Unamortized balances related to past service costs, actuarial gains and losses and transitional obligations are separately recognized on the balance sheet as a component of accumulated other comprehensive income or, in the case of entities with activities subject to rate regulation, as regulatory assets or liabilities for recovery from, or refund to, customers in future rates. Subsequent changes to past service costs, actuarial gains and losses and transitional obligations would be recognized as part of pension expense, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation's rate-regulated subsidiaries will recognize the funded status of their defined benefit pension plans on the balance sheet with the above-noted unamortized balances recognized as regulatory assets or liabilities.

US GAAP also requires that OPEB costs be recorded on an accrual basis, and prohibits the recognition of regulatory assets or liabilities associated with OPEB costs that are recovered on a cash basis. FortisAlberta has historically recovered its OPEB costs on a cash basis, as opposed to an accrual basis, and continues to do so as ordered by its regulator. Therefore, FortisAlberta's regulatory asset associated with OPEB costs does not meet the criteria for recognition under US GAAP. Historically, Newfoundland Power had also recovered its OPEB costs on a cash basis. However, in December 2010, the regulator approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset associated with the adoption of accrual accounting over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the regulator for rate-setting purposes. The rules under US GAAP related to accounting for OPEBs by rate-regulated entities require that Newfoundland Power derecognize its OPEB regulatory asset as at January 1, 2010 on the premise that, as at that date, Newfoundland Power was recovering its OPEB costs on a cash basis. However, the regulatory asset is re-recognized through earnings in accordance with US GAAP in 2010 based on the regulator's approval of Newfoundland Power's application to adopt the accrual method of accounting for OPEBs, effective January 1, 2011, and to recover the associated transitional regulatory asset over a 15-year period.

Additional differences between Canadian GAAP and US GAAP in terms of accounting for defined benefit plans include the determination of the measurement date and the attribution period over which pension expense is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end. However, US GAAP requires the entity's fiscal year end to be used as the measurement date. Canadian GAAP also allows for the use of an attribution period for defined benefit pension plans, under specific circumstances, that extends beyond the date when the credited service period ends, while US GAAP allows for the use of an attribution period for defined benefit pension plans up to the date when credited service ends. The above differences impact the calculation of the Corporation's consolidated benefit obligation, which is mostly offset by a corresponding change to regulatory assets or liabilities.

With the exception of a one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its ability to subsequently re-recognize this OPEB regulatory asset through earnings in 2010, the impact of adopting US GAAP with respect to accounting for employee future benefits does not have a material impact on the Corporation's consolidated earnings.

Brilliant Power Purchase Agreement ("BPPA"): FortisBC Electric's BPPA is required to be accounted for as a capital lease under US GAAP. While the requirement to evaluate whether an arrangement includes a lease is similar between Canadian GAAP and US GAAP, the effective date for prospective adoption of lease accounting guidance differs, resulting in an accounting difference with respect to the BPPA.

Fulfillment of the BPPA is dependent on the use of a specific asset, the Brilliant Hydroelectric Plant ("Brilliant"), and the conveyance to FortisBC Electric of the right to use that asset under an arrangement between FortisBC Electric and the legal owner of Brilliant. The BPPA qualifies as a capital lease as the present value of the minimum lease payments to be made by FortisBC Electric represents recovery of the entire amount of the initial investment in Brilliant by the legal owner over the term of the arrangement.

The effect of retrospectively recognizing Brilliant as a capital lease upon adoption of US GAAP includes the recognition on the consolidated balance sheet of a utility capital asset with a corresponding capital lease obligation for an equivalent amount. Each subsequent reporting period, the total amount of amortization and interest expense to be recognized under capital lease accounting will differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the BCUC. This timing difference is recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA.

Since US GAAP allows for entities to account for the effects of rate regulation, the impact of adopting capital lease accounting for Brilliant does not affect the Corporation's consolidated earnings.

Lease-In Lease-Out ("LILO") Transactions: FEI had entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. Under Canadian GAAP, the lease of the assets to the municipalities has been accounted for as a sales-type lease and the leaseback of the assets as an operating lease. Gains recorded on the lease-out of the assets were deferred and are being amortized over the term of the leaseback arrangements.

Under US GAAP, the natural gas distribution assets are considered to be equipment that is integral to FEI's operations and, therefore, the LILO transactions must be evaluated as real estate sale-leaseback transactions. As a result of this evaluation, the transactions are required to be accounted for as financing transactions under US GAAP. Under the financing method, the assets subject to the sale-leaseback arrangements are recorded as utility capital assets on the Corporation's consolidated balance sheet and subsequently depreciated. Sale proceeds received are recorded as long-term debt. Lease payments, less the portion considered to be interest expense, decrease the long-term debt. The deferred gains, and amortization thereof, which were recorded in accordance with Canadian GAAP are not recognized under US GAAP.

The retrospective impact of accounting for FEI's LILO transactions under US GAAP results in a decrease in opening retained earnings as at January 1, 2010. The impact on the Corporation's consolidated earnings is not material.

Reclassification of preference shares: Currently under Canadian GAAP, the Corporation's First Preference Shares, Series C and Series E are classified as long-term liabilities with associated dividends classified as finance charges. Under US GAAP, the First Preference Shares, Series C and Series E do not meet the criteria for recognition as a financial liability. Therefore, upon the adoption of US GAAP, the Corporation is reclassifying its First Preference Shares, Series C and Series E from long-term liabilities to shareholders' equity on the consolidated balance sheet. The associated dividends are not recorded as finance charges on the Corporation's consolidated statement of earnings but, rather, are recorded as earnings attributable to preference equity shareholders.

Corporate income taxes: Under Canadian GAAP, the Corporation has calculated and recognized corporate income taxes using substantively enacted corporate income tax rates. Under US GAAP, the Corporation is required to calculate and record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of US GAAP, the Corporation is required to recognize the impact of the difference between enacted tax rates and substantively enacted tax rates related to the calculation of Part VI.1 tax deductions associated with preference share dividends. The retrospective adjustment to recognize the Part VI.1 tax deductions based on enacted corporate income tax rates results in a reduction in opening retained earnings under US GAAP and annual earnings thereafter. However, the adjustments will reverse once pending Canadian federal legislation is passed and proposed corporate income tax rate changes are enacted.

The above-noted items do not represent a complete list of differences between US GAAP and Canadian GAAP. Other less significant differences have also been identified and accounted for. A detailed reconciliation between the Corporation's audited Canadian GAAP and audited US GAAP financial statements for 2011, including 2010 comparatives, is disclosed as part of the voluntary filing of the Corporation's audited US GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives.

The audited quantification and reconciliation of the Corporation's consolidated balance sheets as at December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows.

- Total assets as at December 31, 2011 increase by approximately $603 million (December 31, 2010 – $502 million). The increase is due primarily to increases in regulatory assets and utility capital assets in accordance with US GAAP.

- Total liabilities as at December 31, 2011 increase by approximately $337 million (December 31, 2010 – $234 million). The increase is due primarily to the increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP, partially offset by the reclassification of preference shares from liabilities to shareholders' equity.

- Shareholders' equity as at December 31, 2011 increases by approximately $266 million (December 31, 2010 – $268 million). The increase is due primarily to the reclassification of preference shares from liabilities to shareholders' equity in accordance with US GAAP, partially offset by a reduction in retained earnings of approximately $37 million (December 31, 2010 – $30 million), an increase in accumulated other comprehensive loss of approximately $21 million (December 31, 2010 – $14 million) and other miscellaneous changes in shareholders' equity based on the retrospective application of US GAAP. Approximately half of the reduction in retained earnings results from higher corporate income taxes, as referred to above, and is expected to reverse in a future period once pending Canadian federal income tax legislation is passed and proposed Part VI.1 tax rate changes are enacted.

As previously indicated, and subject to the above-noted one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its subsequent ability to re-recognize this OPEB regulatory asset in 2010, there are no material adjustments to the Corporation's consolidated 2010 and 2011 earnings under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The audited quantification and reconciliation of the Corporation's consolidated statements of earnings for the years ended December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows.

- *Year ended December 31, 2011:* Consolidated net earnings recognized in accordance with US GAAP increase by $10 million (from $356 million to $366 million). The increase is due primarily to the reclassification of preference share dividends totalling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by a reduction in earnings attributable to common equity shareholders of approximately $7 million.

- *Year ended December 31, 2010:* Consolidated net earnings recognized in accordance with US GAAP, prior to the one-time adjustment to re-recognize Newfoundland Power's OPEB regulatory asset, increase by approximately $6 million (from $323 million to $329 million). The increase is due primarily to the reclassification of preference share dividends totalling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by a reduction in earnings attributable to common equity shareholders of approximately $11 million.

- The one-time, non-recurring adjustment to re-recognize Newfoundland Power's OPEB regulatory asset in 2010 increases earnings attributable to common equity shareholders for the year ended December 31, 2010 by approximately $46 million. This adjustment does not impact retained earnings as at December 31, 2010, compared to retained earnings reported in accordance with Canadian GAAP as at December 31, 2010, as it reverses an adjustment made to derecognize the OPEB regulatory asset upon adoption of US GAAP as at January 1, 2010.

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	**2011**		2010	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**45**	**49**	42	40
Long-term debt, including current portion (1)	**5,788**	**7,143**	5,669	6,431
Preference shares, classified as debt (2)	**320**	**348**	320	344

(1) Carrying value as at December 31, 2011 excludes unamortized deferred financing costs of $43 million (December 31, 2010 – $42 million) and capital lease obligations of $40 million (December 31, 2010 – $38 million)

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $634 million as at December 31, 2011 (December 31, 2010 – carrying value $592 million; fair value $615 million).

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 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. 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 fair value of the Corporation's preference shares is determined using quoted market prices.

The Financial Instruments table above excludes the long-term other asset associated with the Corporation's previous investment in Belize Electricity, which was expropriated by the GOB in June 2011. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts.

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 financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31, 2011 and 2010.

Derivative Financial Instruments

As at December 31	**2011**				2010	
Liability	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Foreign exchange forward contract	**< 1**	**1**	**–**	**–**	–	–
Fuel option contracts	**< 1**	**2**	**(1)**	**(1)**	–	–
Natural gas derivatives:						
Swaps and options	**Up to 3**	**143**	**(135)**	**(135)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**57**	**–**	**–**	(5)	(5)

The foreign exchange forward contract is held by FEI to hedge the cash flow risk related to approximately US$4 million remaining to be paid under a contract for the implementation of a customer care information system. FEVI was also party to a foreign exchange forward contract to hedge the cash flow risk related to US dollar payments under a contract for the construction of the LNG storage facility on Vancouver Island. During 2011 FEVI's foreign exchange forward contract matured.

The fuel option contracts are held by Caribbean Utilities. During 2011 the Company's Fuel Price Volatility Management Program was approved by the regulator to reduce the impact of volatility in fuel prices on customer rates and Caribbean Utilities entered into two fuel option contracts.

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 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 temper gas price volatility on customer rates and to reduce the risk of regional price discrepancies. 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 foreign exchange forward contract, fuel option contracts and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the derivative financial instruments were recognized in accounts payable as at December 31, 2011 and 2010.

The foreign exchange forward contract is valued using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. The fuel option contracts are valued using published market prices for similar commodities. The natural gas derivatives are valued 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 foreign exchange forward contract, fuel option contracts and natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet date.

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 Canadian 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 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 they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected for entities not subject to rate regulation. 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. As at December 31, 2011, Fortis recognized $1,195 million in current and long-term regulatory assets (December 31, 2010 – $1,095 million) and $601 million in current and long-term regulatory liabilities (December 31, 2010 – $527 million).

Capital Asset Amortization: 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, 2011, the Corporation's consolidated utility capital assets, income producing properties and intangible assets totalled approximately $9.6 billion, or approximately 71% of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangible assets totalling approximately $9.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2010. The increase in capital assets was primarily associated with capital expenditures, which totalled approximately $1.2 billion in 2011. Amortization costs for 2011 were $419 million compared to $410 million for 2010. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization costs.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authority. As required by their respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. The accrual of the estimated costs is included with amortization costs and the provision balance is recognized as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recognized against the regulatory liability when incurred. The estimate of the asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2011 was $354 million (December 31, 2010 – $339 million). The amount of asset removal and site restoration costs provided for and recognized in amortization costs during 2011 was $53 million (2010 – $50 million).

The amortization 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 amortization studies are performed at the regulated utilities. Based on the results of these amortization studies, the impact of any over- or under-amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization costs, when the differences are refunded or collected in customer rates as approved by the regulator. A depreciation study performed at Newfoundland Power during the first half of 2011, based on capital assets in service as at December 31, 2010, indicates an accumulated amortization variance of approximately $18 million. Subject to regulator approval, this variance is expected to increase the amortization of capital assets in future years, which will be recovered in future customer rates. Amortization studies were performed at the FortisBC Energy companies, FortisBC Electric and FortisAlberta during 2011 that have been filed as part of rate applications filed with the respective regulators. The impact of those studies will be determined based on final rate decisions by the regulators, which are expected in 2012.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A future income tax asset or liability is determined for each temporary difference based on the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. Future 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 that the allowance is created or revised. Estimates of the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance might vary from actual amounts incurred.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test 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. 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 below its carrying value. Fair market value is determined using net present value financial models and management's assumption of the future profitability of the reporting units. As at October 1 of each year, the Corporation reviews for impairment of goodwill. There was no impairment provision required on approximately \$1.6 billion of goodwill recognized on the Corporation's consolidated balance sheet as at December 31, 2011.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans 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 obligations are the discount rate for the accrued 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 2012, is 6.76%, which is down slightly from 6.88% used in 2011. The defined benefit pension plan assets experienced total positive returns of approximately \$42 million in 2011 compared to expected positive returns of \$47 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed weighted-average discount rate used to measure the accrued pension benefit obligations on the applicable measurement dates in 2011 and determine net pension cost for 2012 is 4.65%, compared to the assumed weighted-average discount rate used to measure the accrued pension benefit obligations in 2010 and determine net pension cost for 2011 of 5.37%. 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 \$7 million increase in consolidated defined benefit net pension cost for 2011 compared to 2010, mainly as a result of the impact of lower assumed discount rates for calculating net pension cost in 2011 compared to 2010 and the amortization of net actuarial losses that arose in prior years.

Consolidated defined benefit net pension cost for 2012 is expected to be higher than for 2011, driven mainly by decreases in discount rates assumed in the measurement of the pension obligations. The increased costs are expected to be recovered in customer rates at the regulated utilities, subject to forecast risk at some of the smaller utilities.

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 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recognized in the Corporation's 2011 Consolidated Financial Statements, as well as the impact on the accrued defined benefit pension obligation. 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, 2011

Increase (decrease)	Net pension benefit cost		Accrued benefit asset		Accrued benefit liability		Accrued benefit obligation [(1)]	
($ millions)	Regulated Gas Utilities [(1)]	Regulated Electric Utilities	Regulated Gas Utilities [(1)]	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
Impact of increasing the rate of return assumption by 100 basis points	3	(5)	(3)	5	–	–	43	2
Impact of decreasing the rate of return assumption by 100 basis points	(2)	5	2	(5)	–	–	(35)	(6)
Impact of increasing the discount rate assumption by 100 basis points	(7)	(8)	6	8	(2)	–	(66)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	8	10	(6)	(10)	2	–	82	89

(1) At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the accrued benefit pension obligation, is based off of 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 accrued benefit pension obligation. The direction of the impact of a change in the rate of return on plan asset assumption at the FortisBC Energy companies 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 accrued pension 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 related obligation. Similar assumptions as described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan cost and obligations.

As approved by the respective regulator, the cost of OPEB plans at FortisAlberta, and at Newfoundland Power until December 31, 2010, is recovered in customer rates based on the cash payments made. The cost of defined benefit pension plans at FortisAlberta is also 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. Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being recovered in customer rates based on the accrual method of accounting for OPEBs. As discussed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the FortisBC Energy companies and FortisBC Electric, and Newfoundland Power beginning in 2011, have regulator-approved mechanisms to defer variations in net pension cost from forecast 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 mechanism at the FortisBC Energy companies and FortisBC Electric will continue in the future as it is dependent on future regulatory decisions and orders.

As at December 31, 2011, for all defined benefit and OPEB plans, the Corporation had a consolidated accrued benefit asset of $87 million (December 31, 2010 – $94 million) and a consolidated accrued benefit liability of $168 million (December 31, 2010 – $157 million). During 2011 the Corporation recognized a consolidated net benefit cost of $54 million (2010 – $38 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, there were no amounts recognized as at December 31, 2011 and 2010, with the exception of AROs recognized by FortisBC Electric.

As at December 31, 2011, FortisBC Electric has recognized an approximate $4 million ARO (December 31, 2010 – $3 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, 2011, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

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.

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, 2011, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $341 million (December 31, 2010 – $342 million) on annual consolidated revenue of approximately $3,747 million for 2011 (2010 – $3,657 million).

Capitalized Overhead: As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utiltiies and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but do 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. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million). 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 effect on the Corporation's consolidated financial position or results of operations.

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

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 has begun the appeal process associated with 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 has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake 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 $13.5 million in damages 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 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. 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, 2011, 2010 and 2009. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2011**	2010	2009
Revenue	**3,747**	3,657	3,641
Net earnings	**356**	323	292
Net earnings attributable to common equity shareholders	**318**	285	262
Total assets	**13,562**	12,909	12,139
Long-term debt and capital lease obligations (excluding current portion)	**5,679**	5,609	5,276
Preference shares (1)	**912**	912	667
Common shareholders' equity	**3,877**	3,305	3,193
Basic earnings per common share	**1.75**	1.65	1.54
Diluted earnings per common share	**1.74**	1.62	1.51
Dividends declared per common share (2)	**1.17**	1.41	0.78
Dividends declared per First Preference Share, Series C (2)	**1.3625**	1.7031	1.0219
Dividends declared per First Preference Share, Series E (2)	**1.2250**	1.5313	0.9188
Dividends declared per First Preference Share, Series F (2)	**1.2250**	1.5313	0.9188
Dividends declared per First Preference Share, Series G (2)	**1.3125**	1.6406	0.9844
Dividends declared per First Preference Share, Series H (2) (3)	**1.0625**	1.1636	–

(1) Includes preference shares classified as equity and long-term debt

(2) 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

(3) A total of 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H were issued on January 26, 2010 at $25.00 per share for net after-tax proceeds of $242 million, which are entitled to receive cumulative dividends in the amount of $1.0625 per share per annum for the first five years.

2011/2010: Revenue increased $90 million, or 2.5%, over 2010 and net earnings attributable to common equity shareholders grew to $318 million, up $33 million from 2010. For a discussion of the reasons for the increases 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 was primarily due to the Corporation's continued investment in energy infrastructure, driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2011 of committed 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 increased 10 cents, or 6%, from 2010, mainly due to 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 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.

2010/2009: Revenue increased $16 million, or 0.4%, over 2009. The increase was mainly due to: (i) base customer rate increases at the regulated utilities in Canada, combined with the accrual of electricity rate revenue at FortisAlberta related to its regulator-approved revenue requirements for 2010; (ii) customer growth; (iii) contribution from Algoma Power for a full year in 2010; and (iv) the flow through to customers of generally higher energy supply costs at the electric utilities. The above increases were partially offset by the flow through to customers of lower natural gas commodity costs, the unfavourable impact of foreign currency translation and lower consumption of natural gas. Net earnings attributable to common equity shareholders grew to $285 million, up $23 million from 2009. The increase in earnings was mainly due to improved performance at the Corporation's Canadian regulated utilities associated with: (i) rate base growth driven by the electric utilities in western Canada; (ii) an increase in the allowed ROEs for the FortisBC Energy companies from July 1, 2009 and for FortisBC Electric from January 1, 2010, as well as an increase in the equity component of capital structure at FEI from January 1, 2010; (iii) customer growth at FortisAlberta; and (iv) electricity sales growth at Newfoundland Power. The improvement in earnings was also due to increased earnings from non-regulated hydroelectric generation operations, mainly due to the newly constructed Vaca hydroelectric generating facility in Belize, and lower effective corporate income taxes at Fortis Properties. The improvement in earnings also reflected the favourable $9 million year-over-year impact of the reversal in 2010, as approved by the regulator, of a provision taken in the fourth quarter of 2009 for the project cost overrun related to the conversion of Whistler customer appliances from propane to natural gas. The increase in earnings was partially offset by lower contributions from Caribbean Regulated Electric Utilities, driven by unfavourable foreign currency translation, the inability of Belize Electricity to earn a fair and reasonable return due to regulatory challenges and continued unfavourable economic conditions, and higher corporate expenses mainly related to dividends on preference shares issued in January 2010 and business development costs incurred in 2010. The growth in total assets was primarily due to the Corporation's continued investment in energy infrastructure, driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. The increase in long-term debt was in support of energy infrastructure investment. Basic earnings per common share increased 11 cents, or 7%, from 2009, mainly due to increased earnings for the reasons discussed above. Dividends declared per common and preference share for 2010 increased over 2009 primarily due to the timing of the declaration of dividends. First quarter 2010 dividends were declared in January 2010, when normally they would have been declared in the fourth quarter of the preceding year.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the quarters ended December 31, 2011 and 2010. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. A discussion of the financial results for the fourth quarter of 2011 is also contained in the Corporation's fourth quarter 2011 media release, dated and filed on SEDAR at www.sedar.com on February 9, 2012, 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)*		
	2011	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
FortisBC Energy Companies	**62,753**	60,398	2,355	**477**	479	(2)
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,232**	4,255	(23)	**102**	99	3
FortisBC Electric	**843**	847	(4)	**81**	73	8
Newfoundland Power	**1,527**	1,488	39	**156**	152	4
Other Canadian Electric Utilities	**568**	578	(10)	**84**	87	(3)
	7,170	7,168	2	**423**	411	12
Regulated Electric Utilities – Caribbean	**174**	270	(96)	**70**	84	(14)
Non-Regulated – Fortis Generation	**112**	137	(25)	**9**	9	–
Non-Regulated – Fortis Properties				**58**	57	1
Corporate and Other				**7**	7	–
Inter-Segment Eliminations				**(7)**	(13)	6
Total				**1,037**	1,034	3

Factors Contributing to Gas Volumes Variance

Favourable

- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes, reflecting improving economic conditions favourably affecting the forestry and mining sectors

Unfavourable

- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011

Factors Contributing to Energy and Electricity Sales Variances

Unfavourable

- Lower electricity sales at Caribbean Regulated Electric Utilities due to the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, and reduced energy consumption due to challenging economic conditions in the region and the high cost of fuel, partially offset by growth in the number of customers and warmer temperatures in the region during the fourth quarter of 2011, which favourably impacted customer air conditioning load. Excluding Belize Electricity, electricity sales increased 3.7% quarter over quarter.
- Lower energy sales at Non-Regulated – Fortis Generation related to decreased production in Upper New York State, due to a generating plant being out of service since May 2011, partially offset by increased production in Belize because of higher rainfall
- Lower energy deliveries at FortisAlberta, associated with lower average consumption by the gas sector due to decreased activity as a result of low gas market prices; decreased average consumption by the oilfield sector; and lower average consumption by residential customers due to warmer-than-normal temperatures in the fourth quarter of 2011. The above decreases were partially offset by growth in the number of customers and higher average consumption by farm and irrigation customers, due to differences in rainfall year over year.
- Lower electricity sales at Other Canadian Regulated Electric Utilities, driven by lower average consumption by residential customers in Ontario reflecting more moderate temperatures, which decreased home-heating load, and lower average consumption by industrial customers on PEI due to a reduction in farm crop storage and warehousing activities. The above decreases were partially offset by growth in the number of residential customers, and higher average consumption by residential customers on PEI, reflecting cooler temperatures, which increased home-heating load.

Favourable

- Increased electricity sales at Newfoundland Power, associated with growth in the number of customers, and higher average consumption reflecting the higher concentration of electric-versus-oil heating in new home construction, combined with strong economic growth

Factors Contributing to Revenue Variance

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the Corporation's Canadian regulated utilities
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities
- Growth in the number of customers, mainly at FortisAlberta
- Higher gas sales

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011 reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower base component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant in 2011

Segmented Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions, except per share amounts)	**2011**	2010	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**51**	45	6
Regulated Electric Utilities – Canadian			
FortisAlberta	***17***	*17*	–
FortisBC Electric	***11***	*10*	*1*
Newfoundland Power	***8***	*9*	*(1)*
Other Canadian Electric Utilities	***4***	*5*	*(1)*
	40	41	(1)
Regulated Electric Utilities – Caribbean	**3**	4	(1)
Non-Regulated – Fortis Generation	**5**	6	(1)
Non-Regulated – Fortis Properties	**5**	7	(2)
Corporate and Other	**(18)**	(18)	–
Net Earnings Attributable to Common Equity Shareholders	**86**	85	1
Basic Earnings per Common Share *($)*	**0.46**	0.49	(0.03)

Factors Contributing to Earnings Variance

Favourable

- Higher earnings at the FortisBC Energy companies driven by rate base growth, lower-than-expected corporate income taxes and finance charges in 2011, and higher gas transportation volumes to the forestry and mining sectors, partially offset by both lower customer additions and capitalized AFUDC

Unfavourable

- Lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011 and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011 and higher electricity sales
- Lower earnings at Other Canadian Regulated Electric Utilities, mainly associated with decreased electricity sales and higher operating expenses
- Lower earnings at Caribbean Regulated Electric Utilities, reflecting lower earnings at Fortis Turks and Caicos associated with higher amortization costs and operating expenses, partially offset by reduced energy supply costs in 2011
- Lower earnings at Fortis Properties, mostly due to higher corporate income taxes

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2011**	2010	Variance
Cash, Beginning of Period	**108**	64	44
Cash Provided by (Used in):			
Operating Activities	**227**	198	29
Investing Activities	**(369)**	(333)	(36)
Financing Activities	**124**	180	(56)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(1)**	–	(1)
Cash, End of Period	**89**	109	(20)

Cash flow from operating activities, after working capital adjustments, was $29 million higher quarter over quarter, mainly due to favourable changes in working capital and higher earnings. Favourable working capital changes associated with accounts receivable and inventories were partially offset by unfavourable changes in accounts payable.

Cash used in investing activities was $36 million higher quarter over quarter. The increase was due to a $49 million deferred payment being made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002. The deferred payment was originally classified in long-term other liabilities. Cash used in investing activities also increased as a result of the acquisition of the Hilton Suites Winnipeg Airport hotel in October 2011. The above increases were partially offset by higher proceeds from the sale of utility capital assets associated with the sale of joint-use poles at Newfoundland Power in October 2011.

Cash provided by financing activities was $56 million lower quarter over quarter, due to: (i) lower proceeds from long-term debt; (ii) higher repayments of short-term borrowings; and (iii) lower advances from non-controlling interests in the Waneta Partnership, partially offset by lower repayments of both long-term debt and committed credit facility borrowings classified as long-term.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2010 through December 31, 2011. 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 Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected 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 *($)*	Earnings per Common Share Diluted *($)*
December 31, 2011	1,037	86	0.46	0.45
September 30, 2011	702	57	0.31	0.31
June 30, 2011	849	58	0.33	0.33
March 31, 2011	1,159	117	0.67	0.65
December 31, 2010	1,034	85	0.49	0.47
September 30, 2010	719	45	0.26	0.26
June 30, 2010	834	55	0.32	0.32
March 31, 2010	1,070	100	0.58	0.56

A summary of the past eight quarters mainly reflects the Corporation's continued organic growth, 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 Fortis 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 third quarter ended September 30, 2011 included the $11 million after-tax termination fee paid to Fortis by CVPS. Financial results for the fourth quarter ended December 31, 2011 reflected the acquisition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011. 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. For further information, refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of this MD&A. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with the 2010 revenue requirements decision at FortisAlberta. The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since that date.

December 2011/December 2010: Net earnings attributable to common equity shareholders were $86 million, or $0.46 per common share, for the fourth quarter of 2011 compared to earnings of $85 million, or $0.49 per common share, for the fourth quarter of 2010. A discussion of the variances between the financial results for the fourth quarter of 2011 and the fourth quarter of 2010 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2011/September 2010: Net earnings attributable to common equity shareholders were $57 million, or $0.31 per common share, for the third quarter of 2011 compared to earnings of $45 million, or $0.26 per common share, for the third quarter of 2010. The increase in earnings was mainly due to the $11 million after-tax fee paid to Fortis in July 2011, following the termination of the Merger Agreement between Fortis and CVPS. Results also improved due to rate base growth associated with energy infrastructure investment, mainly at the regulated utilities in western Canada, a net foreign exchange gain of approximately $2.5 million after tax associated with the previously hedged investment in Belize Electricity, lower-than-expected operating costs at the FortisBC Energy companies due to the timing of spending and capitalization of certain operating expenses in 2011 and a higher allowed ROE at Algoma Power. The above increases in earnings were partially offset by the impact of the regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009 related to the conversion of Whistler customer appliances from propane to natural gas, the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility since June 2011, lower capitalized AFUDC at FortisBC Electric, lower non-regulated hydroelectric generation in Belize and the timing of recording the 2010 revenue requirements decision at FortisAlberta. The favourable cumulative impact of the decision was recorded in the third quarter of 2010 when the decision was received.

June 2011/June 2010: Net earnings attributable to common equity shareholders were $58 million, or $0.33 per common share, for the second quarter of 2011 compared to earnings of $55 million, or $0.32 per common share, for the second quarter of 2010. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, driven by rate base growth associated with energy infrastructure investment mainly at the electric utilities in western Canada, return earned on additional investment in automated meters at FortisAlberta, as approved by the regulator, lower market-priced purchased power costs at FortisBC Electric and a higher allowed ROE at Algoma Power. Results also improved due to lower corporate business development costs. The above increases in earnings were partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011, lower non-regulated hydroelectric generation in Belize, and lower contribution from Fortis Properties reflecting lower occupancies at hotel operations in western Canada and increased operating expenses. During the second quarter of 2011, the GOB expropriated the Corporation's investment in Belize Electricity.

March 2011/March 2010: Net earnings attributable to common equity shareholders were $117 million, or $0.67 per common share, for the first quarter of 2011 compared to earnings of $100 million, or $0.58 per common share, for the first quarter of 2010. The increase was mainly due to improved performance at the regulated utilities in western Canada, driven by overall rate base growth associated with energy infrastructure investment, higher energy sales at FortisBC Electric and FortisAlberta, the timing of recording the cumulative impact of FortisAlberta's and FEWI's 2010 revenue requirements decisions and a $1 million gain on the sale of property at FortisAlberta, partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011. Earnings also increased due to lower corporate business development costs and higher non-regulated hydroelectric generation in Belize.

MANAGEMENT'S EVALUATION 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, 2011 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 financial statements for external purposes in accordance with Canadian 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, 2011 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2011, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

On February 21, 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 Acquisition"). 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 closing of the Acquisition, which is expected in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.5 billion over the five-year period 2012 through 2016, should support continuing growth in earnings and dividends.

The Corporation continues to pursue acquisitions for profitable growth, focusing on regulated electric and natural gas utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

OUTSTANDING SHARE DATA

As at March 12, 2012, the Corporation had issued and outstanding 189.3 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; and 10.0 million First Preference Shares, Series H. Only the common shares of the Corporation have voting rights.

The number of common shares that would be issued upon conversion of share options, and First Preference Shares, Series C and First Preference Shares, Series E as at March 12, 2012 is as follows:

Conversion of Securities into Common Shares

As at March 12, 2012 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	4.7
First Preference Shares, Series C	4.0
First Preference Shares, Series E	6.5
Total	15.2

Additional information, including the Fortis 2011 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

Table of Contents

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2011 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 Canada. Financial information contained elsewhere in the 2011 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 2011 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2011 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 2011 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

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

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, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, retained earnings 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 Canadian generally accepted accounting principles, 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 about whether the consolidated financial statements are free from 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, the consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
March 13, 2012

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	2011	2010
Current assets		*(Note 34)*
Cash and cash equivalents	**$ 89**	$ 109
Accounts receivable *(Note 29)*	**644**	655
Prepaid expenses	**19**	17
Regulatory assets *(Note 5)*	**210**	241
Inventories *(Note 6)*	**134**	168
Future income taxes *(Note 22)*	**24**	14
	1,120	1,204
Assets held for sale *(Note 7)*	**–**	45
Other assets *(Note 8)*	**270**	168
Regulatory assets *(Note 5)*	**985**	854
Future income taxes *(Note 22)*	**8**	16
Utility capital assets *(Note 9)*	**8,687**	8,185
Income producing properties *(Note 10)*	**594**	560
Intangible assets *(Note 11)*	**341**	324
Goodwill *(Note 12)*	**1,557**	1,553
	$ 13,562	$ 12,909
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 29)*	**$ 159**	$ 358
Accounts payable and accrued charges	**914**	953
Dividends payable	**60**	54
Income taxes payable	**33**	30
Regulatory liabilities *(Note 5)*	**43**	60
Current installments of long-term debt and capital lease obligations *(Note 13)*	**106**	56
Future income taxes *(Note 22)*	**5**	6
	1,320	1,517
Other liabilities *(Note 14)*	**323**	308
Regulatory liabilities *(Note 5)*	**558**	467
Future income taxes *(Note 22)*	**685**	629
Long-term debt and capital lease obligations *(Note 13)*	**5,679**	5,609
Preference shares *(Note 15)*	**320**	320
	8,885	8,850
Shareholders' equity		
Common shares *(Note 16)*	**3,032**	2,578
Preference shares *(Note 15)*	**592**	592
Contributed surplus	**14**	12
Equity portion of convertible debentures *(Note 13)*	**–**	5
Accumulated other comprehensive loss *(Note 18)*	**(74)**	(94)
Retained earnings	**905**	804
	4,469	3,897
Non-controlling interests *(Note 19)*	**208**	162
	4,677	4,059
	$ 13,562	$ 12,909

Commitments *(Note 30)*
Contingent Liabilities *(Note 32)*

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)	**2011**	2010
		(Note 34)
Revenue	**$ 3,747**	$ 3,657
Expenses		
Energy supply costs	**1,697**	1,686
Operating	**865**	822
Amortization	**419**	410
	2,981	2,918
Operating income	**766**	739
Other income (expenses), net *(Note 20)*	**40**	13
Finance charges *(Note 21)*	**370**	362
Earnings before corporate taxes	**436**	390
Corporate taxes *(Note 22)*	**80**	67
Net earnings	**$ 356**	$ 323
Net earnings attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**318**	285
	$ 356	$ 323
Earnings per common share *(Note 16)*		
Basic	**$ 1.75**	$ 1.65
Diluted	**$ 1.74**	$ 1.62

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
Balance, beginning of year	**$ 804**	$ 763
Net earnings attributable to common and preference equity shareholders	**347**	313
	1,151	1,076
Dividends on common shares	**(217)**	(244)
Dividends on preference shares classified as equity	**(29)**	(28)
Balance, end of year	**$ 905**	$ 804

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)	**2011**	2010
Net earnings	**$ 356**	$ 323
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and tax *(Note 18)*	**2**	(12)
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity *(Notes 8 and 18)*	**17**	–
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 18)*	**1**	1
	20	(11)
Comprehensive income	**$ 376**	$ 312
Comprehensive income attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**338**	274
	$ 376	$ 312

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)	**2011**	2010
		(Note 34)
Operating activities		
Net earnings	**$ 356**	$ 323
Items not affecting cash:		
Amortization – utility capital assets and income producing properties	**380**	368
Amortization – intangible assets	**42**	40
Amortization – other	**(3)**	2
Future income taxes *(Note 22)*	**4**	(3)
Accrued employee future benefits	**18**	8
Equity component of allowance for funds used during construction *(Note 20)*	**(13)**	(15)
Other	**(4)**	2
Change in long-term regulatory assets and liabilities	**26**	9
	806	734
Change in non-cash operating working capital *(Note 26)*	**98**	(2)
	904	732
Investing activities		
Change in other assets and other liabilities	**(52)**	–
Capital expenditures – utility capital assets	**(1,086)**	(1,008)
Capital expenditures – income producing properties	**(30)**	(19)
Capital expenditures – intangible assets	**(58)**	(46)
Contributions in aid of construction	**75**	67
Proceeds on sale of utility capital assets and income producing properties *(Note 7)*	**51**	15
Business acquisition, net of cash acquired *(Note 24)*	**(25)**	–
	(1,125)	(991)
Financing activities		
Change in short-term borrowings	**(198)**	(56)
Proceeds from long-term debt, net of issue costs	**343**	523
Repayments of long-term debt and capital lease obligations	**(36)**	(329)
Net (repayments) borrowings under committed credit facilities	**(145)**	8
Net advances from non-controlling interests	**81**	45
Issue of common shares, net of costs and dividends reinvested	**345**	22
Issue of preference shares, net of costs	**–**	242
Dividends		
Common shares, net of dividends reinvested	**(151)**	(135)
Preference shares	**(29)**	(28)
Subsidiary dividends paid to non-controlling interests	**(9)**	(9)
	201	283
Change in cash and cash equivalents	**(20)**	24
Cash and cash equivalents, beginning of year	**109**	85
Cash and cash equivalents, end of year	**$ 89**	$ 109

Supplementary Information to Consolidated Statements of Cash Flows *(Note 26)*

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

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 reporting segment operates as an autonomous unit, 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 by utility are as follows:

Regulated Gas Utilities – Canadian

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

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 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. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes 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 include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. 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.

1. Description of the Business (cont'd)

Regulated Utilities (cont'd)

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 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Includes FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is an integrated electric utility and the principal distributor of electricity in the Turks and Caicos Islands. The Company has a combined diesel-powered generating capacity of 65 MW.

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. Effective 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 8 and 31).

Non-Regulated – Fortis Generation

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

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 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:* Includes 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.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "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. The Exploits Partnership sells its output 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 31).

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 expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia 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") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada (Note 24).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI") (formerly Terasen Inc.) and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). 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 proportionate consolidation method of accounting. The financial results of FortisBC Alternative Energy Services Inc. ("FAES") (formerly Terasen Energy Services Inc.) are also reported in the Corporate and Other segment. FAES is a non-regulated wholly owned subsidiary of FHI that provides alternative energy solutions.

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 as administered by the BCUC. The PBR mechanism for FEI expired on December 31, 2009 with a two-year phase-out for differences between forecast 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").

FEI, FEVI, FEWI and FortisBC Electric 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. The BCUC-approved Negotiated Settlement Agreements for 2010 and 2011 for FEI and the 2012–2013 Revenue Requirements Applications for both FortisBC Electric and FEI did not include new PBR mechanisms.

FEI's allowed ROE was 9.50% for 2011 (2010 – 9.50%) on a deemed capital structure of 40% common equity. FEVI's and FEWI's allowed ROEs were 10.00% for 2011 (2010 – 10.00%) on deemed capital structures of 40% common equity. FortisBC Electric's allowed ROE was 9.90% for 2011 (2010 – 9.90%) on a deemed capital structure of 40% common equity.

Previously the allowed ROE at each of FEI, FEVI, FEWI and FortisBC Electric was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond rates. Effective July 1, 2009 for FEI, FEVI and FEWI and effective January 1, 2010 for FortisBC Electric, the BCUC has set the allowed ROEs and has determined that the former automatic adjustment formula used to establish ROEs on an annual basis no longer applies until reviewed further by the BCUC. In November 2011 the BCUC gave notice to the FortisBC Energy companies and FortisBC Electric of its intention to initiate a Generic Cost of Capital Proceeding. The proceeding will take place, beginning in March 2012, to review: (i) the setting of the appropriate cost of capital for a benchmark low-risk utility in British Columbia; (ii) the possible return to an ROE automatic adjustment mechanism for setting an ROE for the benchmark low-risk utility; and (iii) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities in British Columbia without third-party debt.

2. *Nature of Regulation (cont'd)*

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.

FortisAlberta operates 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 2011 (2010 – 9.00%) on a deemed capital structure of 41% common equity. The Company 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.

Previously FortisAlberta's allowed ROE was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond rates. In its November 2009 Generic Cost of Capital Decision, the AUC ordered that the allowed ROE for utilities it regulates in Alberta be set at 9.00% for 2009, 2010 and, on an interim basis, 2011 and that the automatic adjustment formula used to establish the ROE no longer apply until reviewed further by the AUC. In December 2011 the AUC issued its decision on its 2011 Generic Cost of Capital Proceeding establishing the allowed ROE at 8.75% for 2011 and 2012, and at 8.75% for 2013 on an interim basis. The automatic adjustment formula continues to no longer apply.

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 forecast 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 forecast changes in long-term Canada bond rates. For 2010, however, the PUB set Newfoundland Power's allowed ROE at 9.00% on a deemed capital structure of 45% common equity. For 2011 the Company's allowed ROE was 8.38%, as calculated under the automatic adjustment formula, on a deemed capital structure of 45% common equity. In December 2011 the PUB approved Newfoundland Power's application to suspend the operation of the automatic adjustment formula for 2012 and to continue using, on an interim basis, the allowed ROE of 8.38% until there is a full cost of capital review, which is expected in 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.

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* (Prince Edward Island), the *Renewable Energy Act* (Prince Edward Island) and the *Electric Power (Electricity Rate-Reduction) Amendment Act* (Prince Edward Island), also known as the PEI Energy Accord (the "Accord"), which covers the period March 1, 2011 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 2011 (2010 – 9.75%) on a targeted minimum capital structure of 40% common equity.

In November 2010 Maritime Electric signed the Accord with the Government of PEI. Under the terms of the Accord, the Government of PEI is assuming 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 until Point Lepreau is fully refurbished, which is expected by 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 have decreased and customer electricity rates were lowered by approximately 14.0%, effective March 1, 2011, at which time a two-year customer rate freeze commenced.

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.

Canadian Niagara Power's allowed ROE was 8.01% for 2011 (2010 – 8.01%) on a deemed capital structure of 40% common equity effective May 1, 2010. Prior to May 1, 2010, the Company's deemed capital structure was 43.3% common equity. Electricity distribution rates for 2011 and 2010 were based upon a 2009 historical test year.

Effective December 1, 2010, Algoma Power's allowed ROE was 9.85% on a deemed capital structure of 40% common equity and the utility's electricity distribution rates were rebased using forecast 2011 costs. Prior to December 1, 2010, the Company's allowed ROE was 8.57% on a deemed capital structure of 50% common equity and the utility's electricity distribution rates were based upon costs derived from a 2007 historical test year. Algoma Power is 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 contain the provision for a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer electricity rates for 2011 were set in accordance with the licences, translating into a targeted allowed rate of return on rate base assets ("ROA") range of 7.75% to 9.75% (2010 – 7.75% to 9.75%). The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the RCAM and annually approves capital expenditures.

Fortis Turks and Caicos
Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through FortisTCI and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated January and October 1987, and November 1986 (collectively, the "Agreements"), respectively. Among other matters, the Agreements describe how electricity rates are to be set by the Interim Government of the Turks and Caicos Islands ("Interim Government"), using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.50% (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").

Fortis Turks and Caicos makes annual submissions to the Interim Government calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2011 calculated the Allowable Operating Profit for 2011 to be $30 million (US$29 million) and the Cumulative Shortfall at December 31, 2011 to be $73 million (US$72 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses.

In August 2011 Fortis Turks and Caicos filed with the Interim Government an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. In February 2012 the Interim Government approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Belize Electricity
Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services, and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licence conditions. The basic customer electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery and the second is the cost of fuel and purchased power, including the variable cost of generation, which is a flow through in customer rates. The value-added delivery component of the tariff allows the Company to recover its operating expenses, T&D expenses, taxes and amortization, and an allowed ROA. As a result of the June 2008 Final Decision by the PUC, the allowed ROA for Belize Electricity was 10.00% for 2011 (2010 – 10.00%). The allowed ROA, however, was not achieved due to regulatory challenges. On June 20, 2011, the Corporation's investment in Belize Electricity was expropriated by the GOB (Note 31).

3. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011; however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"). As a qualifying entity with rate-regulated activities, Fortis elected the one-year deferral and, therefore, prepared its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants ("CICA") Handbook for all interim and annual periods ending on or before December 31, 2011.

The consolidated financial statements include selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected by entities not subject to rate regulation. The differences are described in this note under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Employee Future Benefits, Income Taxes and Revenue Recognition, and in Note 5.

All amounts presented are in Canadian dollars unless otherwise stated.

Cash and Cash Equivalents

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

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.

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under CICA Handbook Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 5, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100, *Generally Accepted Accounting Principles*, directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Corporation may consult other sources, including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Corporation has determined that all of its regulatory assets and liabilities qualify for recognition under Canadian GAAP, and this recognition is consistent with the general principles of U.S. Financial Accounting Standards Board's Accounting Standard Codification 980, *Regulated Operations*.

Inventories

Inventories are valued at the lower of weighted average cost and net realizable value. When a situation that previously caused inventories to be written down below cost no longer exists, the amount of the write-down is to be reversed.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated amortization, 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 18, 1986. Subsequent additions at Fortis Turks and Caicos are at cost, including the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by the Agreements for US$2.00, in aggregate, as valued in the books of the Companies.

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 amortization provided on the related assets.

As required by their respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. The accrual of the estimated costs is included with amortization costs and the provision balance is recognized as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. As at December 31, 2011, the long-term regulatory liability for asset removal and site restoration costs, net of salvage proceeds, was $354 million (December 31, 2010 – $339 million) (Note 5 *(xx)*).

As permitted by the regulator, FortisBC Electric records actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization as incurred. During 2011 actual asset removal and site restoration costs of approximately $5 million (2010 – $8 million) were incurred at FortisBC Electric, net of salvage proceeds of less than $1 million (2010 – $1 million).

In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, at FortisAlberta, FortisBC Electric, Newfoundland Power and Maritime Electric would be recognized in earnings in the period incurred.

The FortisBC Energy companies, FortisOntario, Caribbean Utilities, Fortis Turks and Caicos and Belize Electricity recognize asset removal and site restoration costs, net of salvage proceeds, in earnings in the period incurred. At the FortisBC Energy companies, actual costs incurred in excess of, or below, the amount provided for in customer rates are recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates. During 2011 actual asset removal and site restoration costs of approximately $15 million were incurred (2010 – $10 million), with $11 million (2010 – $8 million) recorded in operating expenses and $4 million (2010 – $2 million) deferred as a regulatory asset. In the absence of rate regulation, deferral account treatment would not be permitted at the FortisBC Energy companies and all asset removal and site restoration costs, net of salvage proceeds, would be recognized in earnings in the period incurred.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity, as required by their respective regulator, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization costs when they are collected in customer gas and electricity rates. The loss charged to accumulated amortization in 2011 was approximately $18 million (2010 – $24 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 5 *(viii)*).

In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity would be recognized in earnings in the period incurred.

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, Fortis Turks and Caicos and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets but do 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. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million).

As required by their respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity include an equity component in the allowance for funds used during construction ("AFUDC"), which is included in the cost of utility capital assets. Since AFUDC includes both a debt component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. The debt component of AFUDC is deducted from finance charges and the equity component of AFUDC is recognized in other income. AFUDC capitalized during 2011 was $32 million (2010 – $31 million), including an equity component of $13 million (2010 – $15 million) (Notes 20 and 21). AFUDC is charged to earnings through amortization expense over the estimated service lives of the applicable utility capital assets.

As approved by the regulator, FortisAlberta capitalizes to utility capital assets a portion of the amortization of utility capital assets, such as tools and vehicles, used in the construction of other assets. During 2011 amortization costs of approximately $5 million were capitalized (2010 – $5 million).

December 31, 2011 and 2010

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

Utility Capital Assets (cont'd)

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 30).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. When put into service, the inventories are amortized 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.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates for 2011 ranged from 0.4% to 33.3% (2010 – 0.4% to 33.3%). The weighted average composite rate of amortization, before reduction for amortization of contributions in aid of construction, for 2011 was 3.5% (2010 – 3.5%).

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:

	2011		2010	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Gas	**4–62**	**30**	4–53	30
Electricity	**5–75**	**26**	5–75	27
Transmission				
Gas	**4–82**	**35**	4–75	29
Electricity	**20–65**	**26**	10–75	34
Generation	**5–75**	**29**	5–75	33
Other	**3–70**	**10**	3–70	11

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 amortization, where applicable. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is amortized 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. Capital leases are amortized over the lease term. 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. 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. Such intangible assets are not amortized. 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.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and 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 require the use of estimates of the useful lives of the assets.

Amortization rates for 2011 ranged from 1.0% to 25.0% (2010 – 1.0% to 25.0%). The service life ranges and weighted average remaining service life of finite life intangible assets as at December 31 were as follows:

	2011		2010	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**5–10**	**6**	5–10	5
Land, transmission and water rights	**31–75**	**38**	15–65	38
Franchise fees, customer contracts and other	**4–100**	**15**	4–100	10

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity as required by their respective regulator, with no loss, if any, recognized in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization costs when they are collected in customer gas and electricity rates. In the absence of rate regulation, any loss on the retirement or disposal of intangible assets at FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity would be recognized in earnings in the period incurred. The loss charged to accumulated amortization in 2011 was less than $1 million (2010 – $4 million).

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 customers in future rates, subject to regulatory approval. In the absence of rate regulation, any loss on the retirement or disposal of intangible assets would be recognized in earnings in the period incurred.

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.

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, 2011 and 2010.

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 an 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 on capital or assets, 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 amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test 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 goodwill over the implied fair value of goodwill is the impairment amount. 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 below its carrying value. The annual impairment test was performed as at October 1, 2011. No goodwill impairment provision has been determined for the years ended December 31, 2011 and 2010.

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

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 accrued pension benefit obligation and the value of pension cost of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

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 expense. At the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension expense, 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 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.

On January 1, 2000, Newfoundland Power prospectively adopted CICA Handbook Section 3461, *Employee Future Benefits*. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

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 Canadian 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. In the absence of rate regulation, deferral account treatment would not be permitted.

The costs of the defined contribution pension plans and RRSPs 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 other non-pension post-employment benefits ("OPEBs") through defined benefit plans, including certain health and dental coverage, for qualifying members.

The accrued 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 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 respective regulator, the cost of OPEB plans at FortisAlberta, and at Newfoundland Power until December 31, 2010, is recovered in customer rates based on the cash payments made. Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being recovered in customer rates based on the accrual method of accounting for OPEBs. The transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years (Note 5 *(iv)*).

Any difference between the cost recognized under Canadian GAAP and that recovered from customers in current rates for OPEB plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 5 *(iv)*). In the absence of rate regulation, deferral account treatment would not be permitted.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 17). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus 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 recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity. Stock option forfeitures, cancellations and expiries are recognized in earnings in the period incurred as a reduction in compensation expense.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans using the intrinsic value method, recognizing compensation expense over the vesting period on a straight-line basis. The intrinsic value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period.

Foreign Currency Translation

The assets and liabilities of the Corporation's self-sustaining foreign operations, which include Caribbean Utilities, Fortis Turks and Caicos, BECOL, FortisUS Energy and, up to June 20, 2011, Belize Electricity, are denominated in US dollars or a currency pegged to the US dollar and are translated at the exchange rate in effect at the balance sheet date. The exchange rate in effect as at December 31, 2011 was US$1.00=CDN$1.02 (December 31, 2010 – US$1.00=CDN$0.99). The resulting unrealized translation gains and losses 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. Revenue and expenses of the Corporation's self-sustaining foreign operations are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of self-sustaining 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 8 and 31) is no longer a self-sustaining foreign subsidiary of Fortis and, therefore, does not qualify for hedge accounting. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and any corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment are 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.

Financial Instruments

The Corporation designates each of its financial instruments in one of the following five categories: (i) held for trading; (ii) available for sale; (iii) held to maturity; (iv) loans and receivables; or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recognized in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value, with changes in fair value recognized in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recognized in other comprehensive income. Any change in fair value relating to the ineffective portion is recognized immediately in earnings.

At the FortisBC Energy companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not designated in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to deferral account treatment to be recovered from, or refunded to, customers in future rates (Note 5 *(ii)*). In the absence of rate regulation, deferral account treatment of changes in fair value of derivative financial instruments not in a designated qualifying hedging relationship would not be permitted. Generally, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships" in this note.

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded as they are immaterial to the Corporation's consolidated results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities that are classified as other than held for trading as adjustments to the cost of those financial assets and liabilities recorded on the consolidated balance sheet. These transaction costs are amortized to earnings using the effective interest rate method over the life of the related financial instrument.

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

Hedging Relationships

As at December 31, 2011, the Corporation's hedging relationships consisted of fuel option contracts, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

As part of its Fuel Price Volatility Program, as approved by the regulator, Caribbean Utilities entered into two fuel option contracts to reduce the impact of volatility of fuel prices on customer rates. The fair value of the fuel option contracts is calculated using published market prices for similar commodities. Any change in the fair value of the fuel option contracts is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The foreign exchange forward contract is held by FEI to hedge the cash flow risk related to approximately US$4 million (2010 – US$8 million) remaining to be paid under a contract for the implementation of a customer care information system. The fair value of the foreign exchange forward contract is calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. Any change in the fair value of the foreign exchange forward contract at FEI is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

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 is 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, the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet date. As at December 31, 2011, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the 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 regulator.

The Corporation's earnings from, and net investments in, self-sustaining 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 self-sustaining 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 self-sustaining foreign net investments, which 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, future 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 likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future 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 for regulatory purposes, 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 future 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 future income taxes that are expected to be collected or refunded in customer rates once they become payable or receivable (Note 5 *(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 corporate 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. Belize Electricity is subject to corporate tax under the *Income and Business Tax Act* (Belize). Up to April 1, 2010, corporate tax was capped at 1.75% of gross revenue. Effective April 1, 2010, the corporate tax rate increased to 6.50% of gross revenue. The additional 4.75% corporate tax was being deferred by Belize Electricity for recovery from customers in future electricity rates.

Any difference between the income tax expense or recovery recognized under Canadian 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 5 *(i)*). In the absence of rate regulation, deferral account treatment would not be permitted.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future, which were $76 million as at December 31, 2011 (December 31, 2010 – $72 million). Tax information exchange agreements were entered into force in 2011 for Bermuda, the Cayman Islands and the Turks and Caicos Islands. As a result, earnings of Caribbean Utilities and Fortis Turks and Caicos after 2010 are considered exempt surplus and can be repatriated on a tax-free basis.

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 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 required by the regulator, revenue from the sale of electricity by Belize Electricity was recognized as monthly billings were issued to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. Up to June 20, 2011, the difference between recognizing revenue on a billed versus an accrual basis was recorded on the consolidated balance sheet as a regulatory liability (Note 5 *(xxvii)*).

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with the Alberta Electric System Operator ("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, FortisAlberta is 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 is deferred to be recovered from, or refunded to, customers in future rates (Note 5 *(vi)*). In the absence of rate regulation, deferral account treatment would not be permitted.

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 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.

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

Revenue Recognition (cont'd)

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. 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 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, 2011, FortisBC Electric has recognized an approximate $4 million ARO (December 31, 2010 – $3 million), which has been classified as a long-term other liability (Note 14) with the offset to utility capital assets.

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.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian 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 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 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 5 and 32.

4. Future Accounting Changes

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis is adopting accounting principles generally accepted in the United States ("US GAAP") effective January 1, 2012.

Canadian securities rules allow a reporting issuer to file its financial statements prepared in accordance with US GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the U.S. *Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the Ontario Securities Commission ("OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently refers to US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

The Corporation has voluntarily prepared and filed audited US GAAP consolidated financial statements for the year ending December 31, 2011, with 2010 comparatives, as approved by the OSC. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP and filed.

5. Regulatory Assets and Liabilities

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets *(in millions)*	**2011**	2010	**Remaining recovery period *(Years)***
Future income taxes *(i)*	**$ 640**	$ 574	To be determined
Rate stabilization accounts – FortisBC Energy companies *(ii)*	**105**	146	1
Rate stabilization accounts – electric utilities *(iii)*	**55**	44	Various
Regulatory OPEB plan assets *(iv)*	**58**	63	Various
Point Lepreau replacement energy deferral *(v)*	**47**	44	To be determined
AESO charges deferral *(vi)*	**44**	19	1
Deferred energy management costs *(vii)*	**36**	23	1–10
Deferred losses on disposal of utility capital assets *(viii)*	**23**	16	To be determined
Deferred operating overhead costs *(ix)*	**22**	11	Various
Income taxes recoverable on OPEB plans *(x)*	**22**	21	To be determined
Whistler pipeline contribution deferral *(xi)*	**16**	17	48
Customer Care Enhancement Project cost deferral *(xii)*	**13**	–	To be determined
Deferred development costs for capital *(xiii)*	**11**	11	18
Pension cost variance deferral *(xiv)*	**10**	2	3
Deferred costs – smart meters *(xv)*	**8**	8	To be determined
Alternative energy projects cost deferral *(xvi)*	**8**	4	To be determined
Deferred lease costs *(xvii)*	**7**	6	12–30
2010 accrued distribution revenue adjustment rider *(xviii)*	**–**	36	–
Other regulatory assets *(xix)*	**70**	50	Various
Total regulatory assets	**1,195**	1,095	
Less: current portion	**(210)**	(241)	1
Long-term regulatory assets	**$ 985**	$ 854	

5. *Regulatory Assets and Liabilities (cont'd)*

Regulatory Liabilities

(in millions)		**2011**		2010	**Remaining settlement period *(Years)***
Asset removal and site restoration provision *(xx)*	**$**	**354**	$	339	To be determined
Rate stabilization accounts – FortisBC Energy companies *(ii)*		**127**		60	Various
Rate stabilization accounts – electric utilities *(iii)*		**33**		45	Various
AESO charges deferral *(vi)*		**12**		9	1
Income tax variance deferral *(xxi)*		**12**		–	3
Deferred interest *(xxii)*		**10**		7	1–3
Southern Crossing Pipeline deferral *(xxiii)*		**8**		5	3
PBR incentive liabilities *(xxiv)*		**7**		8	1
Unrecognized net gains on disposal of utility capital assets *(xxv)*		**6**		8	To be determined
2010 FEI revenue surplus *(xxvi)*		**–**		7	–
Unbilled revenue liability *(xxvii)*		**–**		5	–
Other regulatory liabilities *(xxviii)*		**32**		34	Various
Total regulatory liabilities		**601**		527	
Less: current portion		**(43)**		(60)	1
Long-term regulatory liabilities	**$**	**558**	$	467	

Description of the Nature of Regulatory Assets and Liabilities

(i) Future Income Taxes

The Corporation recognizes future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Included in future 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 regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the future taxes become payable or receivable. In the absence of rate regulation, future income taxes would have been recognized in earnings as incurred. The regulatory balances related to future income taxes are not subject to a regulatory return.

(ii) 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 forecast 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 forecast natural gas costs as recovered in base rates. 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.

The RSAM is anticipated to be refunded through customer rates over a three-year period. The CCRA, MCRA and GCVA accounts are anticipated to be fully recovered or refunded within the next fiscal year.

The Rate Stabilization Deferral Account ("RSDA") at FEVI was approved by the regulator to accumulate the difference between the actual 2009 revenue surplus and the forecast amount, and to accumulate excess costs recovered from customers for providing service or to draw down such costs where earnings differed from the allowed ROE for 2010 and 2011. In its 2012–2013 Revenue Requirements Application, FEVI has requested the continuance of the RSDA beyond 2011. The RSDA will be refunded to customers in future rates, as to be determined in future revenue requirements applications of the FortisBC Energy companies.

In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recognized in earnings as incurred. The recovery or refund of the rate stabilization accounts is dependent on actual natural gas consumption volumes and on customer rates, as approved by the regulator.

The rate stabilization accounts at the FortisBC Energy companies are detailed as follows.

(in millions)	**2011**	2010
Current regulatory assets		
CCRA	**$ 68**	$ 91
GCVA	**37**	50
MCRA	**–**	5
Total regulatory assets	**$ 105**	$ 146
Current regulatory liabilities		
MCRA	**$ 8**	$ –
RSAM	**11**	4
RSA	**–**	2
	$ 19	$ 6
Long-term regulatory liabilities		
RSAM	**$ 22**	$ 7
RSDA	**86**	47
	$ 108	$ 54
Total regulatory liabilities	**$ 127**	$ 60

(iii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos) 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 forecast 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, 2011 was a net regulatory liability of $7 million (December 31, 2010 – net regulatory liability of $3 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 is being amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recognized in earnings as incurred. The recovery period of the remaining balance of the weather normalization account is yet to be determined as it depends on weather conditions in the future.

As at December 31, 2011, $6 million in pre-2004 costs deferred 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 recovery period of three years. Subsequent to 2003, annual deferral of energy costs to the ECAM account was recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period. In accordance with the PEI Energy Accord which came into effect on March 1, 2011, the balance of the ECAM regulatory liability of $21 million will be refunded to customers commencing in 2013 and, as a result, has been classified as long-term. The remaining settlement period of the post-2003 ECAM is to be determined at a future time.

As at December 31, 2010, the $29 million balance in Belize Electricity's rate stabilization account was in a payable position.

As at December 31, 2011, $5 million (December 31, 2010 – $5 million) of the remaining balance of the rate stabilization accounts in a receivable position at FortisOntario was not subject to a regulatory return. In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed in the period incurred.

5. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(iv) *Regulatory OPEB Plan Assets*

At FortisAlberta, at Newfoundland Power prior to 2011 and at FortisBC Electric prior to 2005, the cash cost of providing OPEB plans is collected in customer rates as permitted by the respective regulator. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC Electric is based on cash costs plus a partial recovery of the full accrual cost of the OPEB plans. The regulatory OPEB plan assets represent the deferred portion of the benefit cost at FortisAlberta, FortisBC Electric and Newfoundland Power that is expected to be recovered from customers in future rates. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for the recovery from customers of OPEB plan costs and that Newfoundland Power's $53 million transitional regulatory OPEB plan asset be amortized and collected from customers in rates equally over 15 years. In the absence of rate regulation, the benefit cost would be recognized on an accrual basis as actuarially determined, with no deferral of costs recorded on the consolidated balance sheet. As at December 31, 2011, regulatory OPEB plan assets at FortisAlberta and FortisBC Electric totalling $13 million (December 31, 2010 – $13 million) were not subject to a regulatory return.

(v) *Point Lepreau Replacement Energy Deferral*

Maritime Electric has regulatory approval to defer the cost of replacement energy related to Point Lepreau during its refurbishment outage. The station has been out of service since 2008 due to refurbishment commencing in that year. The timing and terms of collection of the deferred costs are to be determined by the PEI Energy Commission. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(vi) *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, 2011, the AESO charges deferral account consisted of the 2011 regulatory asset balance of $44 million, which will be collected in customer rates in 2012 through a transmission adjustment rider and is subject to final regulatory review late in 2012. As at December 31, 2011, the AESO charges deferral account also consisted of the 2010 regulatory liability balance of $12 million, which will be refunded in customer rates in 2012 through a transmission adjustment rider, as approved by the regulator. In the absence of rate regulation, the revenue and expenses would be recognized in earnings in the period incurred and deferral account treatment would not be permitted.

(vii) *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. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(viii) *Deferred Losses on Disposal of Utility Capital Assets*

As approved by the regulator, effective January 1, 2010, losses on the retirement or disposal of utility capital assets at the FortisBC Energy companies are recorded in a regulatory deferral account to be recovered from customers in future rates. As part of its 2012–2013 Revenue Requirements Application, the FortisBC Energy companies have proposed that this deferral account treatment be continued for 2012 and 2013 and that the deferred losses be amortized over a period of 20 years, which is consistent with the average service life of the assets to which the losses relate. In the absence of rate regulation, the deferral of losses on the retirement or disposal of utility capital assets would not be permitted.

(ix) *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. In the absence of rate regulation, the operating costs would be expensed in the period incurred and no deferral account treatment would be permitted.

(x) *Income Taxes Recoverable on OPEB Plans*

At FEI 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 regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. In the absence of rate regulation, the income taxes would not be deferred.

(xi) *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 to be recovered from FEWI's customers over a period of 50 years, as approved by the regulator. In the absence of rate regulation, the capital contribution deferral would have been capitalized and amortized to earnings over the life of the asset.

(xii) *Customer Care Enhancement Project Cost Deferral*

The Customer Care Enhancement Project cost deferral represents incremental costs associated with FEI's Customer Care Enhancement Project, as well as amounts resulting from timing differences between when the asset was included in rate base as compared to when the asset was available for use. As part of its 2012–2013 Revenue Requirements Application, FEI has requested that the Customer Care Enhancement Project cost deferral be transferred to utility capital assets and intangible assets and amortized over a period of three years, commencing in 2012. In the absence of rate regulation, the deferral would not have been permitted.

(xiii) *Deferred Development Costs for Capital*

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. In the absence of rate regulation, the deferred development costs for capital would be capitalized; however, the ultimate period of amortization would likely differ.

(xiv) *Pension Cost Variance Deferral*

As approved by the regulator, the pension cost variance deferral at the FortisBC Energy companies reflects the difference between pension and OPEB costs recognized under Canadian GAAP and that recovered from customers in rates. In the absence of rate regulation, the pension and OPEB costs would be expensed in the period incurred.

(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 and are subject to regulatory approval. In the absence of rate regulation, these deferred costs would have been capitalized; however, the method of amortization to earnings would likely differ.

(xvi) *Alternative Energy Projects Cost Deferral*

The alternative energy projects cost deferral account at the FortisBC Energy companies represents costs, net of revenue, associated with the investment in alternative energy solutions. The recovery period of the cost deferral is to be determined by the regulator at a future time. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(xvii) *Deferred Lease Costs*

FortisBC Electric defers lease costs associated with the Brilliant Terminal Station ("BTS") and Trail office building. The capital cost of the BTS, the cost of financing the BTS obligation and the related operating costs are not being fully recovered by FortisBC Electric in current customer rates since those rates include only the BTS lease payments on a cash basis. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, these costs would be expensed in the period incurred.

FortisBC Electric is accounting for the lease of the Trail office building as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term; however, as ordered by the regulator, FortisBC Electric recovers the Trail office lease payments from customers and records the lease costs on a cash basis. This regulatory asset represents the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase. In the absence of rate regulation, these costs would be recognized in earnings on a straight-line basis over the lease term.

The deferred lease costs are not subject to a regulatory return.

(xviii) *2010 Accrued Distribution Revenue Adjustment Rider*

The accrued distribution revenue adjustment rider at FortisAlberta represents the difference in the revenue requirement between the interim rates charged to customers during 2010 and those approved by the regulator for 2010. The balance was collected from customers in 2011. In the absence of rate regulation, revenue would have been $36 million higher in 2011. This balance was not subject to a regulatory return.

5. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xix) 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, 2011, $65 million (December 31, 2010 – $43 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, 2011, $10 million (December 31, 2010 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

(xx) Asset Removal and Site Restoration Provision

As required by the respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. This regulatory liability represents amounts collected in customer electricity rates at FortisAlberta, Newfoundland Power and Maritime Electric in excess of incurred asset removal and site restoration costs. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

During 2011 the amount included in amortization cost associated with the provision for asset removal and site restoration costs was $53 million (2010 – $50 million). During 2011 actual asset removal and site restoration costs, net of salvage proceeds, were $27 million (2010 – $24 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization cost.

(xxi) 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 period of three years, as approved by the regulator. In the absence of rate regulation, deferral account treatment would not be permitted and the income tax variance would be reflected in earnings in the period the change occurred.

(xxii) 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 and between the actual and forecast interest calculated on the average balance of the MCRA account. The deferred interest will be refunded to customers in future rates over one to three years. In the absence of rate regulation, actual interest costs would have been expensed in the period incurred.

(xxiii) Southern Crossing Pipeline Deferral

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing pipeline and that which has been approved in revenue requirements. The deferral is amortized over a period of three years. In the absence of rate regulation, the revenue would be recognized in earnings when services are rendered.

(xxiv) PBR Incentive Liabilities

FEI and FortisBC Electric's regulatory frameworks included PBR mechanisms that allowed for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined under the PBR mechanisms as approved per BCUC orders (Note 2). FEI's regulatory PBR incentive liability of $5 million was refunded to customers during 2011. A portion of FortisBC Electric's regulatory PBR incentive liability was refunded to customers in 2011, with the remainder approved for settlement in 2012. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xxv) Unrecognized Net Gains on Disposal of Utility Capital Assets

As approved by the regulator, this regulatory liability at the FortisBC Energy companies represents the one-time transfer of cumulative unrecognized net gains on disposal of utility capital assets from utility capital asset accumulated amortization. The settlement of this regulatory liability will be determined as part of the final decision on the FortisBC Energy companies' 2012–2013 Revenue Requirements Applications. In the absence of rate regulation, the unrecognized net gains on disposal of utility capital assets would have been recognized in earnings as incurred.

(xxvi) 2010 FEI Revenue Surplus

The 2010 revenue surplus deferral account captured amounts collected in customer rates at FEI in 2010 in excess of certain costs incurred. The revenue surplus was refunded to customers in 2011. In the absence of rate regulation, the deferral would not have been permitted and the revenue surplus would have been recognized as revenue in the period incurred.

(xxvii) Unbilled Revenue Liability

The unbilled revenue liability as at December 31, 2010 related to the difference between revenue recognized on a billed basis and revenue recognized on an accrual basis at Belize Electricity. In the absence of rate regulation, revenue would have been recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted.

(xxviii) 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, 2011, $25 million (December 31, 2010 – $21 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, 2011, $7 million (December 31, 2010 – $10 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the consolidated financial statements would have been as follows:

	(Decrease)/Increase	
(in millions)	**2011**	2010
Regulatory assets	**$ (1,138)**	$ (1,046)
Regulatory liabilities	**(601)**	(527)
Accumulated other comprehensive loss	**32**	45
Opening retained earnings	**(519)**	(457)
Revenue	**$ 323**	$ 341
Energy supply costs	**243**	354
Operating expenses	**82**	62
Amortization	**(51)**	(55)
Finance charges	**(2)**	2
Corporate taxes	**69**	40
Net earnings	**$ (18)**	$ (62)

6. Inventories

(in millions)	**2011**	2010
Gas in storage	**$ 115**	$ 148
Materials and supplies	**19**	20
	$ 134	$ 168

During 2011 inventories of $854 million (2010 – $863 million) were expensed and reported in energy supply costs on the consolidated statement of earnings. Inventories expensed to operating expenses were $15 million for 2011 (2010 – $15 million), which included $10 million for food and beverage costs at Fortis Properties (2010 – $10 million).

7. Assets Held for Sale

In 2010 Bell Aliant 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. The proceeds from the sale of the joint-use poles approximated net book value.

8. Other Assets

(in millions)	**2011**	2010
Deferred pension costs *(Note 23)*	**$ 139**	$ 140
Other asset – Belize Electricity *(Note 31)*	**106**	–
Long-term accounts receivable (due 2040)	**9**	9
Other	**16**	19
	$ 270	$ 168

8. *Other Assets (cont'd)*

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 previously 70% controlled foreign net investment in Belize Electricity has been 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 previous investment in Belize Electricity does not qualify for hedge accounting and, as a result, from June 20, 2011, an approximate $4.5 million foreign exchange gain on the translation of the asset was recognized in earnings for 2011 (Note 20).

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 self-sustaining Belize Electricity, were reclassified to long-term other assets from accumulated other comprehensive loss and were included in the $106 million balance as at December 31, 2011 (Note 18).

The other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable.

9. Utility Capital Assets

2011 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Net Book Value**
Distribution				
Gas	**$ 2,566**	**$ (556)**	**$ (179)**	**$ 1,831**
Electricity	**4,683**	**(1,218)**	**(555)**	**2,910**
Transmission				
Gas	**1,615**	**(416)**	**(118)**	**1,081**
Electricity	**1,072**	**(283)**	**(17)**	**772**
Generation	**1,088**	**(304)**	**–**	**784**
Other	**1,068**	**(378)**	**–**	**690**
Assets under construction	**509**	**–**	**–**	**509**
Land	**110**	**–**	**–**	**110**
	$ 12,711	**$ (3,155)**	**$ (869)**	**$ 8,687**

2010 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Net Book Value
Distribution				
Gas	$ 2,467	$ (494)	$ (183)	$ 1,790
Electricity	4,453	(1,135)	(534)	2,784
Transmission				
Gas	1,328	(383)	(109)	836
Electricity	1,075	(278)	(18)	779
Generation	1,013	(284)	–	729
Other	993	(371)	–	622
Assets under construction	545	–	–	545
Land	100	–	–	100
	$ 11,974	$ (2,945)	$ (844)	$ 8,185

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, 2011, 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, 2011 was $61 million (December 31, 2010 – $59 million) and related accumulated amortization was $26 million (December 31, 2010 – $25 million).

10. Income Producing Properties

2011

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Buildings	**$ 525**	**$ (76)**	**$ 449**
Equipment	**100**	**(43)**	**57**
Tenant inducements	**29**	**(21)**	**8**
Land	**66**	**–**	**66**
Assets under construction	**14**	**–**	**14**
	$ 734	**$ (140)**	**$ 594**

2010

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 503	$ (68)	$ 435
Equipment	86	(36)	50
Tenant inducements	27	(19)	8
Land	64	–	64
Assets under construction	3	–	3
	$ 683	$ (123)	$ 560

11. Intangible Assets

2011

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Computer software	**$ 346**	**$ (159)**	**$ 187**
Land, transmission and water rights	**133**	**(17)**	**116**
Franchise fees, customer contracts and other	**16**	**(13)**	**3**
Assets under construction	**35**	**–**	**35**
	$ 530	**$ (189)**	**$ 341**

2010

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 301	$ (151)	$ 150
Land, transmission and water rights	129	(17)	112
Franchise fees, customer contracts and other	16	(11)	5
Assets under construction	57	–	57
	$ 503	$ (179)	$ 324

11. Intangible Assets (cont'd)

Additions to intangible assets during 2011 were $58 million (2010 – $80 million), approximately $7 million (2010 – $9 million) of which were developed internally. During 2011 fully amortized intangible assets of $25 million (2010 – $35 million) were retired, reducing cost and accumulated amortization.

Included in the cost of land, transmission and water rights as at December 31, 2011 was $64 million (December 31, 2010 – $62 million) not subject to amortization.

As at December 31, 2011, assets under construction primarily related to the Waneta Expansion.

12. Goodwill

(in millions)	**2011**	2010
Balance, beginning of year	**$ 1,553**	$ 1,560
Foreign currency translation impacts	**4**	(7)
Balance, end of year	**$ 1,557**	$ 1,553

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos 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.

13. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	**2011**	2010
Regulated Utilities			
FortisBC Energy Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2010 – 10.71%)	2015 – 2016	**$ 275**	$ 275
Unsecured Debentures –			
5.95% weighted average fixed rate (2010 – 6.06%)	2029 – 2041	**1,620**	1,520
Government loan *(Note 30)*	2012	**20**	–
Obligations under capital leases	2012 – 2017	**14**	13
FortisAlberta			
Unsecured Debentures –			
5.51% weighted average fixed rate (2010 – 5.62%)	2014 – 2050	**1,184**	1,059
FortisBC Electric			
Secured Debentures –			
9.12% weighted average fixed rate (2010 – 9.12%)	2012 – 2023	**40**	40
Unsecured Debentures –			
5.84% weighted average fixed rate (2010 – 5.84%)	2014 – 2050	**600**	600
Obligations under capital leases	2032	**26**	25
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.66% weighted average fixed rate (2010 – 7.67%)	2014 – 2039	**459**	464
Maritime Electric			
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2010 – 7.67%)	2016 – 2061	**167**	137
FortisOntario			
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2010 – 7.09%)	2018 – 2041	**104**	52
Caribbean Utilities			
Unsecured US Senior Loan Notes –			
6.03% weighted average fixed rate (2010 – 6.28%)	2013 – 2031	**207**	179

(in millions)	Maturity Date	**2011**	2010
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. Loan –			
4.82% weighted average fixed and variable rate (2010 – 4.79%)	2013 – 2016	**$ 6**	$ 8
US First Caribbean International Bank loan –			
5.65% fixed rate	2015	**2**	2
Belize Electricity			
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate		**–**	34
Other loans –			
4.63% weighted average fixed rate		**–**	6
Other variable interest rate loans		**–**	10
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**2**	3
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
7.21% weighted average fixed rate (2010 – 7.21%)	2012 – 2017	**131**	139
Senior Notes – 7.32% fixed rate	2019	**12**	13
Corporate – Fortis and FHI			
Unsecured:			
Debentures –			
6.14% weighted average fixed rate (2010 – 6.14%)	2014 – 2039	**326**	326
US Senior Notes –			
5.49% weighted average fixed rate (2010 – 5.49%)	2014 – 2040	**559**	547
US Subordinated Convertible Debentures –			
5.50% fixed rate	2011	**–**	37
Long-term classification of credit facility borrowings *(Note 29)*		**74**	218
Total long-term debt and capital lease obligations		**5,828**	5,707
Less: Deferred financing costs		**(43)**	(42)
Less: Current installments of long-term debt and capital lease obligations		**(106)**	(56)
		$ 5,679	$ 5,609

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.

Regulated Utilities

FortisBC Electric has a capital lease obligation with respect to the operation of the BTS. Future minimum lease payments associated with this capital lease obligation are approximately $3 million per year over the remaining term of the lease agreement to 2032. The capital lease obligation bears interest at a composite rate of 8.62%.

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.

13. Long-Term Debt and Capital Lease Obligations (cont'd)

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.

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 (Note 16).

In April 2010 FHI redeemed in full for cash its $125 million 8.00% capital securities with proceeds from borrowings under the Corporation's committed credit facility. The capital securities were scheduled to mature in April 2040; however, the Company had the option to redeem the capital securities for cash at par on or after April 19, 2010.

Repayment of Long-Term Debt and Capital Lease Obligations

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)*
2012	$ 106	$ –	$ 106
2013	97	–	97
2014	422	280	702
2015	152	–	152
2016	294	–	294
Thereafter	3,872	605	4,477

14. Other Liabilities

(in millions)	**2011**	2010
OPEB plan liabilities *(Note 23)*	**$ 168**	$ 157
Defined benefit pension liabilities *(Note 23)*	**52**	46
Waneta Partnership promissory note	**45**	42
Deferred gains on the sale of natural gas T&D assets	**34**	38
DSU and PSU liabilities *(Note 17)*	**8**	8
Customer deposits	**6**	6
Other liabilities	**10**	11
	$ 323	$ 308

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2011, its discounted net present value was $45 million (December 31, 2010 – $42 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.

The deferred gains on the sale of natural gas T&D assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease obligations are included in the table in Note 30.

Other liabilities primarily include AROs at FortisBC Electric and funds received in advance of expenditures.

15. 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

First Preference Shares	Annual Dividend Per Share	Classification	**2011** Number of Shares	**2011** Amount (in millions)	2010 Number of Shares	2010 Amount (in millions)
Series C	$ 1.3625	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
Series E	$ 1.2250	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt			**12,993,500**	**$ 320**	12,993,500	$ 320
Series F	$ 1.2250	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122
Series G [(1)]	$ 1.3125	Equity	**9,200,000**	**225**	9,200,000	225
Series H [(1)]	$ 1.0625	Equity	**10,000,000**	**245**	10,000,000	245
Total classified as equity			**24,200,000**	**$ 592**	24,200,000	$ 592

[(1)] The First Preference Shares, Series G and Series H are Five-Year Fixed Rate Reset First Preference Shares.

In January 2010 the Corporation issued 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H at $25.00 per share for net after-tax proceeds of approximately $245 million.

As the First Preference Shares, Series C and Series E are convertible at the option of the holder into a variable number of common shares of the Corporation based on a market-related price of such common shares, they meet the definition of financial liabilities and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

As the First Preference Shares, Series F, Series G and Series H are not redeemable at the option of the holder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings to arrive at net earnings attributable to common equity shareholders.

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 preferential cash dividends 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. 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 preferential 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 preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 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.

16. Common Shares

Authorized: an unlimited number of common shares without nominal or par value.

Issued and Outstanding	2011		2010	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Common shares	**188,828**	**$ 3,032**	174,393	$ 2,578

Common shares issued during the year were as follows:

	2011		2010	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**174,393**	**$ 2,578**	171,256	$ 2,497
Public offering	**10,340**	**331**	–	–
Conversion of debentures	**1,374**	**43**	–	–
Consumer Share Purchase Plan	**43**	**1**	51	1
Dividend Reinvestment Plan	**1,888**	**61**	2,100	59
Employee Share Purchase Plan	**–**	**–**	193	5
Stock Option Plans	**790**	**18**	793	16
Balance, end of year	**188,828**	**$ 3,032**	174,393	$ 2,578

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 (Note 13).

Effective June 1, 2010, the Employee Share Purchase Plan ("ESPP") was amended as approved by the Corporation's Board of Directors, such that future shares purchased under the ESPP will be on the open market. The first investment date under this amended ESPP was September 1, 2010.

As at December 31, 2011, 6.3 million (December 31, 2010 – 4.0 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans.

As at December 31, 2011, common shares reserved for issuance under the terms of the Corporation's preference shares were 26.0 million (December 31, 2010 – 26.0 million).

As at December 31, 2011, $3 million (December 31, 2010 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under ESPP and executive stock option loans.

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 181.6 million for 2011 and 172.9 million for 2010.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2011			2010		
	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	**$ 318**	**181.6**	**$ 1.75**	$ 285	172.9	$ 1.65
Effect of potential dilutive securities:						
Stock Options	**–**	**1.0**		–	0.9	
Preference Shares *(Notes 15 and 21)*	**17**	**10.1**		17	11.9	
Convertible Debentures	**2**	**1.2**		2	1.4	
	$ 337	**193.9**		$ 304	187.1	
Deduct anti-dilutive impacts:						
Preference Shares	**(7)**	**(3.9)**		–	–	
Diluted EPS	**$ 330**	**190.0**	**$ 1.74**	$ 304	187.1	$ 1.62

17. 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, 2011, the Corporation had the following stock option plans: 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 Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options issued under this plan are exercised or expire in or before 2016. The Corporation ceased granting options under the 2002 Plan and all options granted after 2006 are under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and 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.

Number of Options	**2011**	2010
Options outstanding, beginning of year	**4,700,203**	4,693,493
Granted	**828,512**	892,744
Cancelled	**(29,359)**	(93,864)
Exercised	**(790,127)**	(792,170)
Options outstanding, end of year	**4,709,229**	4,700,203
Options vested, end of year	**2,572,775**	2,541,374

Weighted Average Exercise Prices	**2011**	2010
Options outstanding, beginning of year	**$ 23.52**	$ 21.83
Granted	**32.95**	27.36
Cancelled	**28.16**	25.68
Exercised	**19.56**	17.61
Options outstanding, end of year	**25.81**	23.52

17. Stock-Based Compensation Plans (cont'd)

Stock Options (cont'd)

Details of stock options outstanding and vested as at December 31, 2011 were as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
5,608	5,608	$ 12.03	2012
79,210	79,210	$ 12.81	2013
204,441	204,441	$ 15.28	2014
10,000	10,000	$ 15.23	2014
1,031	1,031	$ 14.55	2014
313,376	313,376	$ 18.40	2015
28,000	28,000	$ 18.11	2015
6,303	6,303	$ 20.82	2015
341,741	341,741	$ 22.94	2016
489,246	489,246	$ 28.19	2014
34,343	34,343	$ 25.76	2014
678,938	492,949	$ 28.27	2015
863,209	375,937	$ 22.29	2016
835,743	190,590	$ 27.36	2017
818,040	–	$ 32.95	2018
4,709,229	2,572,775		

The weighted average exercise price of stock options vested as at December 31, 2011 was $23.64.

In March 2011 the Corporation granted 828,512 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $32.95 immediately preceding the date of grant. The fair value of each option granted was $4.57 per option.

In March 2010 the Corporation granted 892,744 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $27.36 immediately preceding the date of grant. The fair value of each option granted was $4.41 per option.

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.

	2011	2010
Dividend yield *(%)*	**3.68**	3.66
Expected volatility *(%)*	**23.1**	25.1
Risk-free interest rate *(%)*	**2.00**	2.54
Weighted average expected life *(years)*	**4.5**	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $4 million for the year ended December 31, 2011 (2010 – $4 million).

Directors' DSU Plan

The Corporation's Directors' DSU Plan is an optional means for directors to elect to receive credit for their annual 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. Effective 2006 directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

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	2011	2010
DSUs outstanding, beginning of year	**146,951**	116,904
Granted	**27,070**	24,426
Granted – notional dividends reinvested	**5,429**	5,621
DSUs paid out	**(31,821)**	–
DSUs outstanding, end of year	**147,629**	146,951

For the year ended December 31, 2011, expense of $1 million (2010 – $2 million) was recorded in relation to the DSU Plan.

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, 2011, the total liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $33.37, for a total of approximately $5 million (December 31, 2010 – $5 million), and is included in other liabilities (Note 14).

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	2011	2010
PSUs outstanding, beginning of year	**141,408**	98,133
Granted	**45,000**	60,000
Granted – notional dividends reinvested	**5,329**	5,017
PSUs paid out	**(37,079)**	(21,742)
PSUs outstanding, end of year	**154,658**	141,408

In March 2011 37,079 PSUs were paid out to the President and CEO of the Corporation at a price of $33.11 per PSU, for a total of approximately $1 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in February 2008 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2011, expense of $2 million (2010 – $2 million) was recorded in relation to the PSU Plan.

As at December 31, 2011, the total liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $33.37, for a total of approximately $3 million (December 31, 2010 – $3 million), and is included in other liabilities (Note 14).

18. 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:

	2011		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**$ (138)**	**$ 38**	**$ (100)**
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**56**	**(23)**	**33**
Corporate tax (expense) recovery	**(8)**	**4**	**(4)**
	(90)	**19**	**(71)**
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	**(6)**	**2**	**(4)**
Corporate tax recovery	**2**	**(1)**	**1**
	(4)	**1**	**(3)**
Accumulated other comprehensive loss	**$ (94)**	**$ 20**	**$ (74)**

	2010		
(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 self-sustaining foreign operations	$ (105)	$ (33)	$ (138)
Gains on hedges of net investments in self-sustaining foreign operations	31	25	56
Corporate tax expense	(4)	(4)	(8)
	(78)	(12)	(90)
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(7)	1	(6)
Corporate tax recovery	2	–	2
	(5)	1	(4)
Accumulated other comprehensive loss	$ (83)	$ (11)	$ (94)

The net change in accumulated other comprehensive loss for 2011 includes 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 self-sustaining 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 self sustaining 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 8 and 31).

19. Non-Controlling Interests

(in millions)		**2011**		2010
Waneta Partnership	**$**	**128**	$	44
Caribbean Utilities		**73**		73
Preference shares of Newfoundland Power		**7**		7
Belize Electricity		**–**		38
	$	**208**	$	162

20. Other Income (Expenses), Net

(in millions)		**2011**		2010
Termination fee	**$**	**17**	$	–
Equity component of AFUDC *(Note 3)*		**13**		15
Interest income		**4**		2
Net foreign exchange gain		**4**		1
Other income, net of expenses		**2**		1
Business development expenses		**–**		(6)
	$	**40**	$	13

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.

The net foreign exchange gain includes an approximate $4.5 million foreign exchange gain on the translation into Canadian dollars of the Corporation's long-term other asset associated with Belize Electricity (Note 8), partially offset by an approximate $3.5 million foreign exchange loss on the translation into Canadian dollars of the Corporation's unhedged US dollar borrowings.

The net foreign exchange gain also includes amounts related to foreign currency transactions at Caribbean Utilities.

21. Finance Charges

(in millions)		**2011**		2010
Interest – Long-term debt and capital lease obligations	**$**	**362**	$	352
– Short-term borrowings		**10**		9
Dividends on preference shares *(Notes 15 and 16)*		**17**		17
Debt component of AFUDC *(Note 3)*		**(19)**		(16)
	$	**370**	$	362

22. Corporate Taxes

Future income taxes are provided for temporary differences. Future income tax assets and liabilities comprised the following:

(in millions)	**2011**	2010
Future income tax liability (asset)		
Utility capital assets	**$ 605**	$ 544
Income producing properties	**27**	27
Intangible assets	**32**	26
Regulatory assets	**81**	78
Other assets and liabilities (net)	**(4)**	2
Regulatory liabilities	**(73)**	(58)
Loss carryforwards	**(19)**	(23)
Unrealized foreign currency translation gains on long-term debt	**7**	9
Share issue and debt financing costs	**2**	–
Net future income tax liability	**$ 658**	$ 605
Current future income tax asset	**$ (24)**	$ (14)
Current future income tax liability	**5**	6
Long-term future income tax asset	**(8)**	(16)
Long-term future income tax liability	**685**	629
Net future income tax liability	**$ 658**	$ 605

The components of the provision for corporate taxes were as follows:

(in millions)	**2011**	2010
Canadian		
Current taxes	**$ 71**	$ 68
Future income taxes	**67**	49
Less regulatory adjustments	**(65)**	(50)
	2	(1)
Total Canadian	**$ 73**	$ 67
Foreign		
Current taxes	**$ 5**	$ 2
Future income taxes	**2**	(2)
Total Foreign	**$ 7**	$ –
Corporate taxes	**$ 80**	$ 67

Corporate 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 corporate taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2011**	2010
Combined Canadian federal and provincial statutory income tax rate	**30.5%**	32.0%
Statutory income tax rate applied to earnings before corporate taxes	**$ 133**	$ 125
Preference share dividends	**5**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(12)**	(15)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(13)**	(11)
Items capitalized for accounting purposes but expensed for income tax purposes	**(53)**	(39)
Difference between capital cost allowance and amounts claimed for accounting purposes	**12**	(4)
Non-deductible expenses	**7**	8
Other	**1**	(3)
Corporate taxes	**$ 80**	$ 67
Effective tax rate	**18.3%**	17.2%

As at December 31, 2011, the Corporation had approximately $86 million (December 31, 2010 – $101 million) in non-capital and capital loss carryforwards, of which $13 million (December 31, 2010 – $18 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2031.

23. 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 accrued pension benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, the FortisBC Energy companies, Newfoundland Power and Caribbean Utilities, and as at September 30 of each year for FortisAlberta, FortisBC Electric, FortisOntario and Algoma Power. The most recent actuarial valuation of the pension plans for funding purposes was as of July 1, 2009 for Algoma Power; as of December 31, 2009 for the FortisBC Energy companies (covering non-unionized employees) and FortisOntario; as of December 31, 2010 for the FortisBC Energy companies (covering unionized employees), FortisAlberta and FortisBC Electric; and as of December 31, 2011 for the Corporation, Newfoundland Power and 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 consolidated defined benefit pension plan asset allocation was as follows:

Plan assets as at December 31

(%)	**2011**	2010
Canadian equities	**43**	45
Fixed income	**43**	41
Foreign equities	**9**	9
Real estate	**5**	5
	100	100

December 31, 2011 and 2010

23. Employee Future Benefits (cont'd)

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded or unfunded status:

	2011			2010		
(in millions)	**Accrued Benefit Obligation**	**Plan Assets**	**Net Unfunded**	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
FortisBC Energy Companies	**$ 442**	**$ 315**	**$ (127)**	$ 370	$ 285	$ (85)
FortisAlberta	**33**	**26**	**(7)**	30	22	(8)
FortisBC Electric	**156**	**111**	**(45)**	144	106	(38)
Newfoundland Power	**283**	**276**	**(7)**	256	269	13
Maritime Electric	**2**	**–**	**(2)**	2	–	(2)
FortisOntario [(1)]	**24**	**22**	**(2)**	24	21	(3)
Algoma Power	**20**	**18**	**(2)**	19	15	(4)
Caribbean Utilities	**7**	**4**	**(3)**	6	4	(2)
Fortis	**25**	**5**	**(20)**	21	5	(16)
Total	**$ 992**	**$ 777**	**$ (215)**	$ 872	$ 727	$ (145)

[(1)] Covers eligible employees of Canadian Niagara Power

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2011**	2010	**2011**	2010
Change in accrued benefit obligation				
Balance, beginning of year	**$ 872**	$ 752	**$ 204**	$ 181
Current service costs	**21**	16	**5**	4
Employee contributions	**14**	11	**–**	–
Interest costs	**46**	46	**11**	12
Benefits paid	**(39)**	(36)	**(6)**	(5)
Actuarial loss	**78**	88	**28**	27
Past services costs/plan amendments	**–**	(5)	**1**	(15)
Balance, end of year	**$ 992**	$ 872	**$ 243**	$ 204
Change in value of plan assets				
Balance, beginning of year	**$ 727**	$ 661	**$ –**	$ –
Actual return on plan assets	**42**	67	**–**	–
Benefits paid	**(39)**	(36)	**(6)**	(5)
Employee contributions	**14**	11	**–**	–
Employer contributions	**33**	24	**6**	5
Balance, end of year	**$ 777**	$ 727	**$ –**	$ –
Funded status				
Deficit, end of year	**$ (215)**	$ (145)	**$ (243)**	$ (204)
Unamortized net actuarial loss	**294**	231	**90**	66
Unamortized past service costs	**(1)**	(1)	**(25)**	(31)
Unamortized transitional obligation	**7**	8	**10**	12
Employer contributions after measurement date	**2**	1	**–**	–
Accrued benefit asset (liability), end of year	**$ 87**	$ 94	**$ (168)**	$ (157)
Deferred pension costs *(Note 8)*	**$ 139**	$ 140	**$ –**	$ –
Defined benefit pension liabilities *(Note 14)*	**(52)**	(46)	**–**	–
OPEB plan liabilities *(Note 14)*	**–**	–	**(168)**	(157)
	$ 87	$ 94	**$ (168)**	$ (157)

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2011**	2010	**2011**	2010
Components of net benefit cost				
Current service costs	**$ 21**	$ 16	**$ 5**	$ 4
Interest costs	**46**	46	**11**	12
Actual return on plan assets	**(42)**	(67)	**–**	–
Actuarial loss	**78**	88	**28**	27
Past service costs/plan amendments	**–**	(5)	**1**	(15)
Costs arising in the year	**103**	78	**45**	28
Differences between costs arising and costs recognized in the year in respect of:				
Return on plan assets	**(5)**	21	**–**	–
Actuarial loss	**(58)**	(77)	**(24)**	(25)
Past service costs	**1**	6	**(5)**	13
Transitional obligation and plan amendments	**1**	–	**2**	2
Regulatory adjustment	**(8)**	(1)	**2**	(7)
Net benefit cost	**$ 34**	$ 27	**$ 20**	$ 11
Significant assumptions				
Weighted average discount rate during the year *(%)*	**5.37**	6.16	**5.38**	6.27
Weighted average discount rate as at December 31 *(%)*	**4.65**	5.37	**4.69**	5.38
Weighted average expected long-term rate of return on plan assets *(%)*	**6.76**	6.88	**–**	–
Weighted average rate of compensation increase *(%)*	**3.37**	3.70	**3.41**	3.72
Weighted average health-care cost trend increase as at December 31 *(%)*	**–**	–	**6.59**	6.53
Expected average remaining service life of active employees *(years)*	**4–15**	3–15	**12–16**	10–17

For 2011 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 accrued benefit obligation	**$ 25**	**$ (21)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

23. Employee Future Benefits (cont'd)

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 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

(in millions)	Net Benefit Cost	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation [1]
Impact of increasing the rate of return assumption by 100 basis points	**$ (2)**	**$ 2**	**$ –**	**$ 45**
Impact of decreasing the rate of return assumption by 100 basis points	**3**	**(3)**	**–**	**(41)**
Impact of increasing the discount rate assumption by 100 basis points	**(15)**	**14**	**(2)**	**(137)**
Impact of decreasing the discount rate assumption by 100 basis points	**18**	**(16)**	**2**	**171**

[1] At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the accrued benefit pension obligation, is based off of 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 accrued benefit pension obligation.

During 2011 the Corporation expensed $13 million (2010 – $11 million) related to defined contribution pension plans.

24. Business Acquisition

2011

NON-REGULATED – FORTIS PROPERTIES

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 purchase method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing October 2011.

25. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2011 *($ 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	**1,568**	409	296	573	339	**1,617**	**305**	**34**	**231**	**29**	**(37)**	**3,747**
Energy supply costs	**854**	–	72	369	218	**659**	**192**	**1**	**–**	**–**	**(9)**	**1,697**
Operating expenses	**307**	144	83	75	48	**350**	**40**	**8**	**156**	**10**	**(6)**	**865**
Amortization	**111**	134	45	42	24	**245**	**33**	**4**	**19**	**7**	**–**	**419**
Operating income	**296**	131	96	87	49	**363**	**40**	**21**	**56**	**12**	**(22)**	**766**
Other income (expenses), net	**10**	5	1	–	–	**6**	**3**	**1**	**–**	**21**	**(1)**	**40**
Finance charges	**127**	60	39	36	20	**155**	**14**	**2**	**24**	**71**	**(23)**	**370**
Corporate tax expense (recovery)	**40**	1	10	16	7	**34**	**1**	**2**	**9**	**(6)**	**–**	**80**
Net earnings (loss)	**139**	75	48	35	22	**180**	**28**	**18**	**23**	**(32)**	**–**	**356**
Non-controlling interests	**–**	–	–	1	–	**1**	**8**	**–**	**–**	**–**	**–**	**9**
Preference share dividends	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**29**	**–**	**29**
Net earnings (loss) attributable to common equity shareholders	**139**	75	48	34	22	**179**	**20**	**18**	**23**	**(61)**	**–**	**318**
Goodwill	**908**	227	221	–	63	**511**	**138**	**–**	**–**	**–**	**–**	**1,557**
Identifiable assets	**4,408**	2,452	1,320	1,202	658	**5,632**	**718**	**546**	**610**	**482**	**(391)**	**12,005**
Total assets	**5,316**	2,679	1,541	1,202	721	**6,143**	**856**	**546**	**610**	**482**	**(391)**	**13,562**
Gross capital expenditures (1)	**253**	416	102	81	47	**646**	**71**	**174**	**30**	**–**	**–**	**1,174**
Year ended December 31, 2010 *($ millions)*												
Revenue	1,546	385	266	555	331	1,537	333	36	226	29	(50)	3,657
Energy supply costs	863	–	73	358	215	646	201	1	–	–	(25)	1,686
Operating expenses	288	141	73	62	45	321	48	9	151	10	(5)	822
Amortization	108	126	41	47	23	237	36	4	18	7	–	410
Operating income	287	118	79	88	48	333	48	22	57	12	(20)	739
Other income (expenses), net	9	3	3	–	–	6	3	4	–	(5)	(4)	13
Finance charges	121	54	35	36	21	146	18	4	24	73	(24)	362
Corporate tax expense (recovery)	45	(1)	5	16	8	28	1	2	7	(16)	–	67
Net earnings (loss)	130	68	42	36	19	165	32	20	26	(50)	–	323
Non-controlling interests	–	–	–	1	–	1	9	–	–	–	–	10
Preference share dividends	–	–	–	–	–	–	–	–	–	28	–	28
Net earnings (loss) attributable to common equity shareholders	130	68	42	35	19	164	23	20	26	(78)	–	285
Goodwill	908	227	221	–	63	511	134	–	–	–	–	1,553
Identifiable assets	4,319	2,144	1,263	1,197	646	5,250	779	348	572	505	(417)	11,356
Total assets	5,227	2,371	1,484	1,197	709	5,761	913	348	572	505	(417)	12,909
Gross capital expenditures (1)	253	379	139	78	48	644	72	84	19	1	–	1,073

(1) Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows.

25. Segmented Information (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011, and to FortisOntario; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) 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)	**2011**	2010
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ 7**	$ 24
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Sales from Newfoundland Power to Fortis Properties	**5**	4
Inter-segment finance charges on borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	**1**	4
Corporate to Other Canadian Electric Utilities	**2**	1
Corporate to Regulated Electric Utilities – Caribbean	**4**	3
Corporate to Fortis Generation	**3**	4
Corporate to Fortis Properties	**13**	12

The significant related party inter-segment asset balances as at December 31 were as follows:

(in millions)	**2011**	2010
Inter-segment borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Other Canadian Electric Utilities	**–**	50
Corporate to Regulated Electric Utilities – Caribbean	**76**	60
Corporate to Fortis Generation	**23**	51
Corporate to Fortis Properties	**249**	219
Other inter-segment assets	**23**	17
Total inter-segment eliminations	**$ 391**	$ 417

26. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2011**	2010
Interest paid	**$ 359**	$ 355
Income taxes paid	**67**	51

The following table provides a breakdown of the Corporation's changes in non-cash operating working capital.

(in millions)	**2011**	2010
Accounts receivable	**$ 5**	$ (53)
Prepaid expenses	**(2)**	(1)
Regulatory assets – current portion	**(4)**	18
Inventories	**30**	9
Accounts payable and accrued charges	**57**	(3)
Income taxes payable	**3**	14
Regulatory liabilities – current portion	**9**	14
Change in non-cash operating working capital	**$ 98**	$ (2)

27. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to support energy infrastructure investment and 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 the utilities' customer rates.

The consolidated capital structure of Fortis as at December 31, 2011 compared to December 31, 2010 is presented in the following table.

	2011		2010	
	(in millions)	***(%)***	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**$ 5,855**	**55.0**	$ 5,914	58.4
Preference shares [(2)]	**912**	**8.6**	912	9.0
Common shareholders' equity	**3,877**	**36.4**	3,305	32.6
Total [(3)]	**$ 10,644**	**100.0**	$ 10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Includes preference shares classified as both long-term liabilities and equity
(3) Excludes amounts related to non-controlling interests

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, 2011, 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 and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 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 31 for further information on the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 29.

28. Financial Instruments

The Corporation has designated its non-derivative financial instruments as at December 31 as follows:

(in millions)	2011 Carrying Value	2011 Estimated Fair Value	2010 Carrying Value	2010 Estimated Fair Value
Held for trading				
Cash and cash equivalents [(1)]	**$ 89**	**$ 89**	$ 109	$ 109
Loans and receivables				
Trade and other accounts receivable [(1) (2) (3)]	**644**	**644**	655	655
Other long-term receivables [(1) (3) (4)]	**13**	**13**	15	15
Other asset – Belize Electricity [(4)]	**106**	**–**[(5)]	–	–
Other financial liabilities				
Short-term borrowings [(1) (3)]	**159**	**159**	358	358
Trade and other accounts payable [(1) (3) (6)]	**778**	**778**	786	786
Dividends payable [(1) (3)]	**60**	**60**	54	54
Customer deposits [(1) (3) (7)]	**6**	**6**	6	6
Waneta Partnership promissory note [(7) (8)]	**45**	**49**	42	40
Long-term debt, including current portion [(9) (10)]	**5,788**	**7,143**	5,669	6,431
Preference shares, classified as debt [(9) (11)]	**320**	**348**	320	344

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
(2) Included in accounts receivable on the consolidated balance sheet
(3) Carrying value approximates amortized cost.
(4) Included in long-term other assets on the consolidated balance sheet
(5) The fair value of the Corporation's expropriated investment in Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts.
(6) Included in accounts payable and accrued charges on the consolidated balance sheet
(7) Included in other liabilities on the consolidated balance sheet
(8) Carrying value is a discounted net present value.
(9) Carrying value is measured at amortized cost using the effective interest rate method.
(10) Carrying value as at December 31, 2011 excludes unamortized deferred financing costs of $43 million (December 31, 2010 – $42 million) and capital lease obligations of $40 million (December 31, 2010 – $38 million).
(11) Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $634 million as at December 31, 2011 (December 31, 2010 – $615 million).

The carrying values of financial instruments included in current assets, current liabilities, other assets and other liabilities on the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments.

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 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. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

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 financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

	2011				2010	
Liability	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *(in millions)*	**Estimated Fair Value** *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Foreign exchange forward contract [(1)(2)]	**< 1**	**1**	**$ –**	**$ –**	$ –	$ –
Fuel option contracts [(1)(2)]	**< 1**	**2**	**(1)**	**(1)**	–	–
Natural gas derivatives: [(1)(2)]						
Swaps and options	**Up to 3**	**143**	**(135)**	**(135)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**57**	**–**	**–**	(5)	(5)

(1) The fair value measurements are Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value. Level 2 inputs represent inputs, other than quoted prices in active markets for identical assets or liabilities, that are observable for the asset or liability, either directly as prices or indirectly as derived from prices.

(2) The fair values of the derivatives were recorded in accounts payable as at December 31, 2011 and 2010.

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.

29. 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 and cash equivalents, trade and other accounts receivable, and other long-term 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, 2011, its gross credit risk exposure was approximately $150 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $3 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 high credit-quality institutions in accordance with established credit-approval practices. 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.

December 31, 2011 and 2010

29. Financial Risk Management (cont'd)

Credit Risk (cont'd)

The Corporation is exposed to credit risk associated with the amount and timing of 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. The Corporation has a long-term other asset of $106 million, including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 8 and 31).

The aging analysis of the Corporation's consolidated trade and other accounts receivable, net of an allowance for doubtful accounts of $16 million as at December 31, 2011 (December 31, 2010 – $16 million), excluding derivative financial instruments recorded in accounts receivable as at December 31, was as follows:

(in millions)	**2011**	2010
Not past due	**$ 553**	$ 584
Past due 0–30 days	**65**	56
Past due 31–60 days	**12**	9
Past due 61 days and over	**14**	6
	$ 644	$ 655

As at December 31, 2011, the aging analysis includes amounts owed to BECOL from Belize Electricity, due to the discontinuance of the consolidation method of accounting for Belize Electricity as a result of the expropriation of the utility by the GOB. As at December 31, 2011, BECOL was owed $9.5 million from Belize Electricity related to energy purchases. Approximately $2 million of the accounts receivable past due 31–60 days and $5 million of the accounts receivable past due 61 days and over related to amounts owing to BECOL from Belize Electricity.

As at December 31, 2011, other long-term receivables at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power totalling $13 million (included in long-term other assets) will be received over the next five years and thereafter, with $3 million expected to be received over 2013 and 2014, $1 million over 2015 and 2016 and $9 million due after 2016.

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 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 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 $270 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, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.9 billion was unused. 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 $2.1 billion of the total credit facilities are committed facilities with maturities ranging from 2012 through 2015.

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

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2011**	Total as at December 31, 2010
Total credit facilities	$ 845	$ 1,390	$ 13	**$ 2,248**	$ 2,109
Credit facilities utilized:					
Short-term borrowings	–	(157)	(2)	**(159)**	(358)
Long-term debt *(Note 13)* [(1)]	–	(74)	–	**(74)**	(218)
Letters of credit outstanding	(1)	(65)	–	**(66)**	(124)
Credit facilities unused	$ 844	$ 1,094	$ 11	**$ 1,949**	$ 1,409

[(1)] As at December 31, 2011, credit facility borrowings classified as long-term debt included $16 million (December 31, 2010 – $16 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at December 31, 2011 and 2010, 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.

Corporate and Other

Fortis has an $800 million unsecured committed revolving credit facility, maturing July 2015, and a $15 million unsecured demand credit facility. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the committed revolving credit facility to $1 billion. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

FHI has a $30 million unsecured committed revolving credit facility, maturing May 2012, that is available for general corporate purposes.

Regulated Utilities

FEI has a $500 million unsecured committed revolving credit facility, maturing August 2013. 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 has a $20 million unsecured committed non-revolving credit facility, maturing January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing September 2015, that is utilized to finance capital expenditures and for general corporate purposes. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2012 and the remaining $100 million matures May 2014. 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 credit facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2015, 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 secured lines of credit totalling $20 million, of which $14 million is authorized solely for letters of credit.

Caribbean Utilities has unsecured credit facilities of approximately US$33 million ($33 million), comprised of a capital expenditure line of credit of US$18 million ($18 million), including amounts available for letters of credit, a US$7.5 million ($7.5 million) operating line of credit and a US$7.5 million ($7.5 million) catastrophe standby loan.

Fortis Turks and Caicos has unsecured 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.

29. *Financial Risk Management (cont'd)*

Liquidity Risk (cont'd)

The Corporation and its utilities, which are currently rated, target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2011, the Corporation's credit ratings were as follows:

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

The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, 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. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing (Note 33), DBRS placed the Corporation's credit rating under review with developing implications. Similarly, Standard & Poor's placed the Corporation's credit rating on credit watch with negative implications.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2011.

Financial Liabilities

(in millions)	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years	**Total**
Short-term borrowings	$ 159	$ –	$ –	$ –	**$ 159**
Trade and other accounts payable	778	–	–	–	**778**
Natural gas derivatives [(1)]	88	41	–	–	**129**
Fuel option contracts [(2)]	1	–	–	–	**1**
Foreign exchange forward contract [(3)]	4	–	–	–	**4**
Dividends payable	60	–	–	–	**60**
Customer deposits [(4)]	–	2	1	3	**6**
Waneta Partnership promissory note [(5)]	–	–	–	72	**72**
Long-term debt, including current portion [(6)]	103	791	440	4,454	**5,788**
Interest obligations on long-term debt	356	690	597	5,201	**6,844**
Preference shares, classified as debt	–	123	197	–	**320**
Dividend obligations on preference shares, classified as finance charges	17	25	17	–	**59**
Total	$ 1,566	$ 1,672	$ 1,252	$ 9,730	**$ 14,220**

[(1)] Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2011 at $135 million.

[(2)] Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at $1 million.

[(3)] Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at less than $1 million.

[(4)] Customer deposits were recorded in other liabilities as at December 31, 2011.

[(5)] Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in other liabilities at discounted net present value as at December 31, 2011 at $45 million.

[(6)] Excludes deferred financing costs of $43 million and capital lease obligations of $40 million

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, self-sustaining 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. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining 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 that are 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 self-sustaining foreign subsidiaries, which are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity (Note 8) does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining 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 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. As a result, the Corporation recognized a net foreign exchange gain of approximately $1 million ($1.5 million after tax) in earnings in 2011 (Note 20).

A 5% appreciation or depreciation of the US dollar relative to the Canadian dollar would have: (i) increased or decreased earnings by approximately $6 million for the year ended December 31, 2011 (2010 – $2 million); (ii) increased or decreased long-term other assets by approximately $4 million as at December 31, 2011 (2010 – nil); and (iii) decreased or increased other comprehensive income by $24 million for the year ended December 31, 2011 (2010 – $25 million). This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense, earnings streams from the Corporation's foreign subsidiaries, the translation of the Corporation's long-term other asset associated with its previous investment in Belize Electricity, and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased or decreased other comprehensive income by $28 million for the year ended December 31, 2011 (2010 – $30 million).

FEI's US dollar payments under a contract for the implementation of a customer care information system are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2011, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar, as it impacts the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased or decreased earnings by less than $1 million for the year ended December 31, 2011 (2010 – less than $1 million). Furthermore, FEI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Interest Rate Risk
The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $3 million for the year ended December 31, 2011 (2010 – $4 million). A 25 basis point decrease in interest rates associated with variable-rate debt, with all other variables remaining constant, would have increased earnings by $1 million for the year ended December 31, 2011 (2010 – $1 million). Furthermore, the FortisBC Energy companies and FortisBC Electric have regulatory deferral accounts that mitigate exposure to fluctuations in interest rates associated with variable-rate debt and are recovered from, or refunded to, customers in future rates.

Certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by approximately $1 million for the year ended December 31, 2011 (2010 – $1 million).

Commodity Price Risk
The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk has been minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives 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 with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. In 2011 the BCUC determined that commodity hedging in the current environment was not a cost-effective means to meet the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011–2014 Price Risk Management Plan with the exception of certain elements to address regional price discrepancies. As a result, the FortisBC Energy companies have suspended all commodity hedging activities, with the exception of certain limited swaps as permitted by the BCUC. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

29. Financial Risk Management (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have been less out-of-the-money and, in the absence of rate regulation, other comprehensive income would have increased by $59 million for the year ended December 31, 2011 (2010 – $63 million). However, the FortisBC Energy companies defer any changes in the fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $59 million (December 31, 2010 – $63 million). Had the price of natural gas, with all other variables remaining constant, decreased by $1 per gigajoule, the fair value of the natural gas derivatives would have been further out-of-the-money and, in the absence of rate regulation, other comprehensive income would have decreased by $59 million for the year ended December 31, 2011 (2010 – $62 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $59 million (December 31, 2010 – $62 million).

The Corporation's exposure to market risk related to the foreign exchange forward contract and natural gas derivatives represents an estimate of possible changes in fair value that would occur assuming hypothetical movements in foreign exchange rates and commodity prices. The estimates may not be indicative of actual results and do not represent the maximum possible fair value gains and losses that may occur.

30. Commitments

The Corporation's consolidated commitments in each of the next five years and thereafter, as at December 31, 2011, excluding repayments of long-term debt and capital lease obligations, which are separately disclosed in Note 13, 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
Gas purchase contract obligations [1]	**$ 300**	$ 180	$ 74	$ 46	$ –	$ –	$ –
Power purchase obligations							
FortisBC Electric [2]	**2,430**	47	45	40	41	40	2,217
FortisOntario [3]	**413**	48	49	50	51	52	163
Maritime Electric [4]	**190**	50	38	40	47	1	14
Capital cost [5]	**461**	17	17	19	17	19	372
Operating lease obligations [6]	**152**	26	17	16	16	16	61
Waneta Partnership promissory note [7]	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements [8]	**64**	3	4	4	4	3	46
Defined benefit pension funding contributions [9]	**58**	26	25	3	1	1	2
Office lease – FortisBC Electric [10]	**17**	2	2	2	1	1	9
Other [11]	**7**	1	1	1	1	–	3
Total	**$ 4,164**	$ 400	$ 272	$ 221	$ 179	$ 133	$ 2,959

(1) Gas purchase contract obligations relate to various gas purchase contracts at the FortisBC Energy companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2011.

(2) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. 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. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases 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. Additionally, in November 2011 FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "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. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount 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.

(3) 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.

(4) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In November 2010 the Company signed a new five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The new contract includes fixed pricing for the entire five-year period and covers, among other things, replacement energy and capacity for Point Lepreau. 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.

(5) 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, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(6) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases. They also include the operating lease obligations, up to April 2012, associated with the electricity distribution assets of Port Colborne Hydro and $7 million for the exercised election under the operating lease agreement to purchase the remaining assets of Port Colborne Hydro in April 2012.

(7) 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.

(8) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration 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 facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 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. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

(9) 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, 2011 – Newfoundland Power
December 31, 2012 – FortisBC Energy companies (covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (covering unionized employees)
December 31, 2013 – FortisBC Electric

(10) On September 29, 1993 FortisBC Electric began leasing an office building in Trail, British Columbia for a term of 30 years. The terms of the agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

Notes to Consolidated Financial Statements

December 31, 2011 and 2010

30. Commitments (cont'd)

(11) Other contractual obligations include building operating leases, AROs and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

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 consolidated capital program of the Corporation, including capital spending at its non-regulated operations, is forecast to be approximately $1.3 billion for 2012 and $5.5 billion in total from 2012 through 2016, which has not been included in the commitments table above.

In prior years, FEVI received non-interest bearing repayable loans from the 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 loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates.

As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the commitments table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos 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.

31. Expropriated Assets

Belize Electricity

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet (Note 8).

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

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 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. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

32. Contingent Liabilities

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

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

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 has begun the appeal process associated with 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 has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake 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 $13.5 million in damages 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 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

33. Subsequent Event

On February 21, 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 Acquisition"). 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 closing of the Acquisition, which is expected to occur in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

34. Comparative Figures

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes related to: (i) a $58 million decrease in cash from financing activities associated with the issuance of common shares and a corresponding decrease in cash used in financing activities associated with dividends paid on common shares; (ii) a $17 million increase in long-term regulatory assets and a corresponding decrease in utility capital assets associated with a change in presentation at the FortisBC Energy companies; and (iii) a $13 million increase in other income (expenses) net, offset by a $7 million decrease in revenue, a $6 million decrease in operating expenses and a $12 million increase in finance charges associated with a change in the presentation of other income (expenses), net on the consolidated statement of earnings.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2011**	2010 [1]	2009 [1]
Revenue, including equity income	**3,747**	3,657	3,641
Energy supply costs and operating expenses	**2,562**	2,508	2,577
Amortization	**419**	410	364
Other income (expenses), net	**40**	13	10
Finance charges	**370**	362	369
Corporate taxes	**80**	67	49
Results of discontinued operations, gains on sales and other unusual items	**–**	–	–
Net earnings	**356**	323	292
Net earnings attributable to non-controlling interests	**9**	10	12
Net earnings attributable to preference equity shareholders	**29**	28	18
Net earnings attributable to common equity shareholders	**318**	285	262
Balance Sheets *(in $ millions)*			
Current assets	**1,120**	1,204	1,124
Goodwill	**1,557**	1,553	1,560
Other long-term assets	**1,263**	1,083	917
Utility capital assets, income producing properties and intangible assets	**9,622**	9,069	8,538
Total assets	**13,562**	12,909	12,139
Current liabilities	**1,320**	1,517	1,592
Other long-term liabilities	**1,566**	1,404	1,288
Long-term debt and capital lease obligations (excluding current portion)	**5,679**	5,609	5,276
Preference shares (classified as debt)	**320**	320	320
Total liabilities	**8,885**	8,850	8,476
Shareholders' equity	**4,677**	4,059	3,663
Cash Flows *(in $ millions)*			
Operating activities	**904**	732	681
Investing activities	**1,125**	991	1,045
Financing activities	**390**	455	563
Dividends, excluding dividends on preference shares classified as debt	**189**	172	176
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.86**	8.79	8.41
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease obligations (net of cash)	**55.0**	58.4	60.2
Preference shares (classified as debt and equity)	**8.6**	9.0	6.9
Common shareholders' equity	**36.4**	32.6	32.9
Interest Coverage *(x)*			
Debt	**2.1**	2.0	1.9
All fixed charges	**2.0**	1.9	1.8
Total Gross Capital Expenditures *(in $ millions)*	**1,174**	1,073	1,024
Common Share Data			
Book value per share (year end) *($)*	**20.53**	18.92	18.61
Average common shares outstanding *(in millions)*	**181.6**	172.9	170.2
Basic earnings per common share *($)*	**1.75**	1.65	1.54
Dividends declared per common share *($)*	**1.170**	1.410	0.780
Dividends paid per common share *($)*	**1.160**	1.120	1.040
Dividend payout ratio *(%)*	**66.3**	67.9	67.5
Price earnings ratio *(x)*	**19.1**	20.6	18.6
Share Trading Summary			
High price *($)* (TSX)	**35.45**	34.54	29.24
Low price *($)* (TSX)	**28.24**	21.60	21.52
Closing price *($)* (TSX)	**33.37**	33.98	28.68
Volume *(in thousands)* (TSX)	**126,341**	120,855	121,162

(1) Certain 2010 and 2009 comparative figures have been reclassified to comply with current period classifications, including the reporting of other income (expenses), net separately on the statement of earnings. Figures prior to 2009 have not been restated. Refer to Note 34 of the 2011 Annual Consolidated Financial Statements for further details.

(2) As at December 31, 2006, the regulatory provision for asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric due to a change in presentation adopted by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2008	2007	2006 (2)	2005 (2)	2004	2003	2002
3,907	2,718	1,472	1,441	1,146	843	715
2,859	1,904	939	926	766	579	477
348	273	178	158	114	62	65
–	–	–	–	–	–	–
363	299	168	154	122	86	74
65	36	32	70	47	38	32
–	8	2	10	–	–	–
272	214	157	143	97	78	67
13	15	8	6	6	4	4
14	6	2	–	–	–	–
245	193	147	137	91	74	63
1,150	1,038	405	299	293	191	180
1,575	1,544	661	512	514	65	60
487	424	331	471	418	345	241
7,954	7,276	4,049	3,315	2,713	1,563	1,459
11,166	10,282	5,446	4,597	3,938	2,164	1,940
1,697	1,804	558	412	538	296	334
727	697	482	477	138	62	39
4,884	4,623	2,558	2,136	1,905	1,031	941
320	320	320	320	320	123	–
7,628	7,444	3,918	3,345	2,901	1,512	1,314
3,538	2,838	1,528	1,252	1,037	652	626
661	373	263	304	272	157	134
852	2,033	634	467	1,026	308	349
387	1,826	456	224	777	232	261
191	146	77	64	51	38	35
8.70	10.00	11.87	12.40	11.28	12.30	12.23
59.5	64.3	61.1	58.7	61.4	60.0	65.2
7.3	5.2	10.0	8.6	9.4	6.7	–
33.2	30.5	28.9	32.7	29.2	33.3	34.8
1.9	1.9	2.2	2.5	2.3	2.2	2.3
1.8	1.7	2.0	2.1	2.0	2.1	2.2
935	803	500	446	279	208	229
17.97	16.69	12.19	11.74	10.45	8.82	8.50
157.4	137.6	103.6	101.8	84.7	69.3	65.1
1.56	1.40	1.42	1.35	1.07	1.06	0.97
1.010	0.880	0.700	0.605	0.548	0.525	0.498
1.000	0.820	0.670	0.588	0.540	0.520	0.485
64.1	58.6	47.2	43.7	50.3	48.9	49.9
15.8	20.7	21.0	18.0	16.2	13.9	13.5
29.94	30.00	30.00	25.64	17.75	15.24	13.28
20.70	24.50	20.36	17.00	14.23	11.63	10.76
24.59	28.99	29.77	24.27	17.38	14.73	13.13
132,108	100,920	60,094	37,706	29,254	31,180	21,676

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 17, 2012	August 17, 2012
November 16, 2012	February 14, 2013

Dividend Payment Dates

June 1, 2012	September 1, 2012
December 1, 2012	March 1, 2013

Earnings Release Dates

May 2, 2012	July 31, 2012
November 1, 2012	February 7, 2013

* *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.computershare.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

Friday, May 4, 2012
10:30 a.m.
Delta St. John's
120 New Gower Street
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)] to Common Shareholders as a convenient method of increasing 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; and First Preference Shares, Series H 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 and FTS.PR.H, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

Manager, Investor and Public Relations
T: 709.737.2800
F: 709.737.5307
E: investorrelations@fortisinc.com

Investor Information

Fortis Inc. Officers

H. Stanley Marshall
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

Cover photos by:
Shawn Talbot Photography, Kelowna, BC
Ka-Kei Law Creative, Vancouver, BC

Photography:
David Batten, Goodwood, ON
Larry Doell, Rossland, BC
Barrett & MacKay, Cornwall, PEI
Sergei Belski, Airdrie, AB
Ned Pratt, St. John's, NL

Design and Production:
Colour, St. John's, NL
www.colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

Board of Directors

David G. Norris ✱ ✷ ★
Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Peter E. Case ✱
Corporate Director
Kingston, Ontario

Frank J. Crothers ★
Chairman and CEO, Island Corporate Holdings
Nassau, Bahamas

Ida J. Goodreau ✷
Corporate Director
Vancouver, British Columbia

Douglas J. Haughey ✱
President and CEO, Provident Energy Ltd.
Calgary, Alberta

H. Stanley Marshall
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

John S. McCallum ✱ ★
Professor of Finance, University of Manitoba
Winnipeg, Manitoba

Harry McWatters ★
Wine Consultant
Summerland, British Columbia

Ronald D. Munkley ✷ ★
Corporate Director
Mississauga, Ontario

Michael A. Pavey ✱ ✷
Corporate Director
Moncton, New Brunswick

Roy P. Rideout ✷ ★
Corporate Director
Halifax, Nova Scotia

✱ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies please visit www.fortisinc.com.

FORTIS INC.

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

T: 709.737.2800
F: 709.737.5307

www.fortisinc.com
TSX:FTS