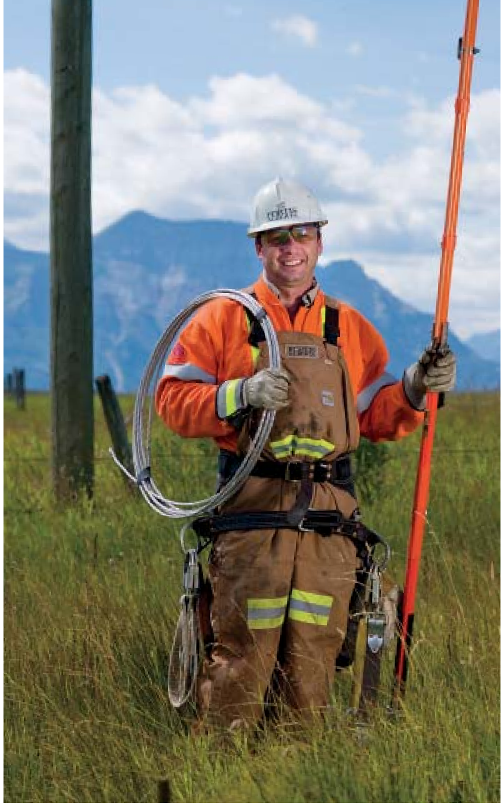
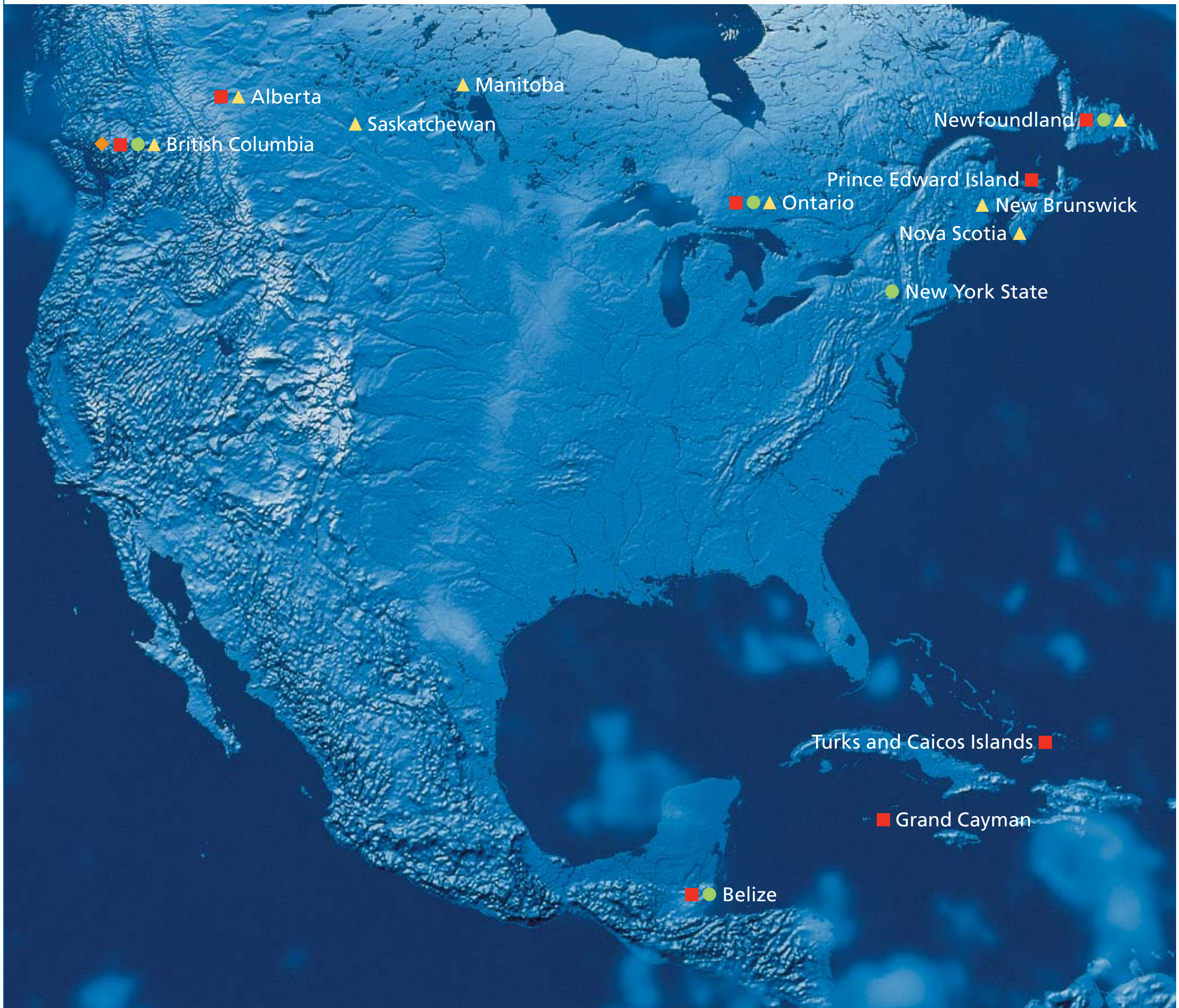
Fortis Inc. 2010 Annual Report



FORTIS INC.

2010 ANNUAL REPORT

Operations



Regulated Utility Operations

Gas Operations

Terasen *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation

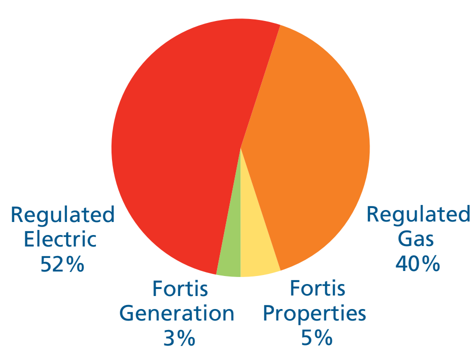
Production Areas
Belize, Ontario, Central Newfoundland, British Columbia, New York State

Fortis Properties

Real Estate and Hotels
Across Canada

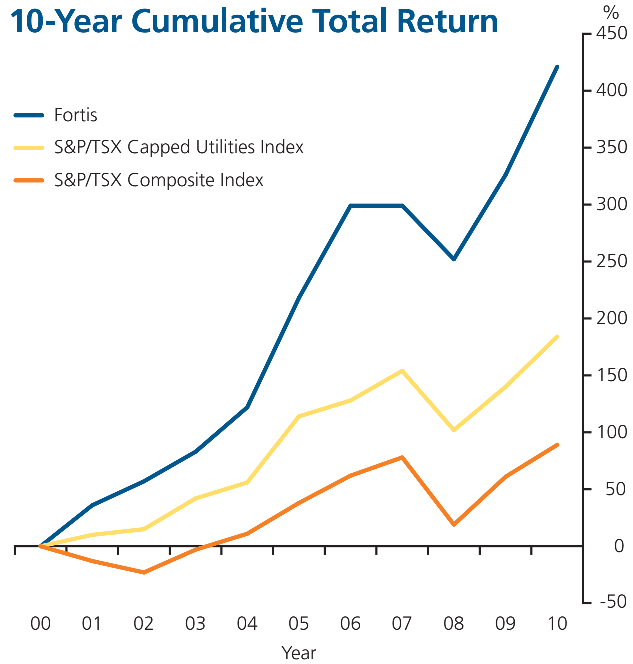
Total Assets Approach $13 Billion

(as at December 31, 2010)



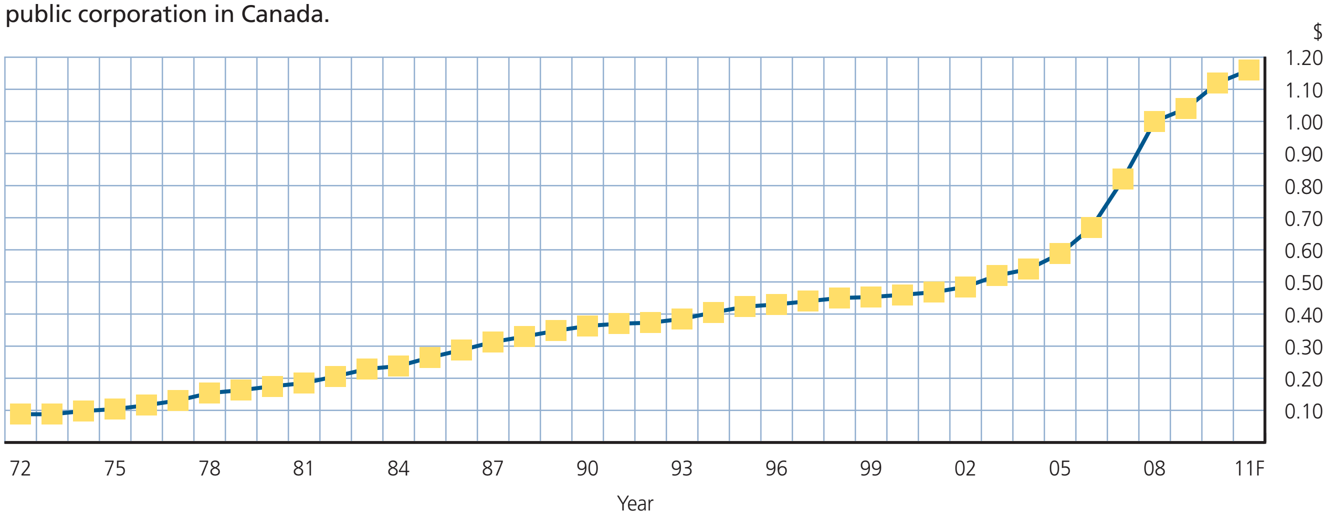
Contents

10-Year Cumulative Total Return



Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 38 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.

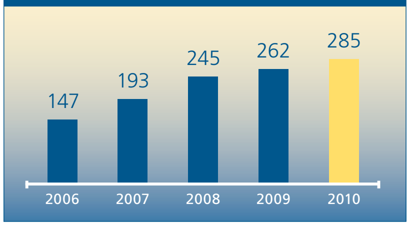
ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

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.

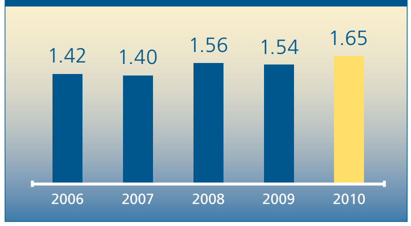
Investor Highlights

Five-Year Performance

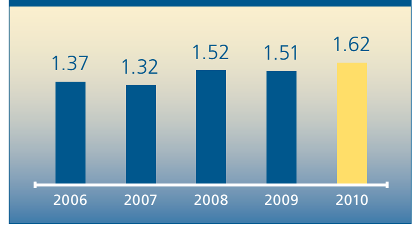
Earnings Applicable to Common Equity Shareholders ($M)



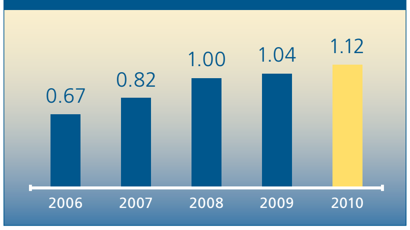
Basic Earnings per Common Share ($)



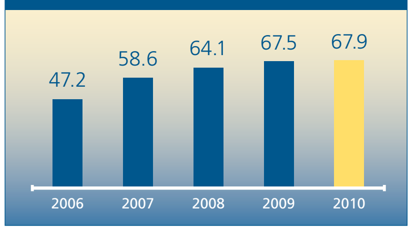
Diluted Earnings per Common Share ($)



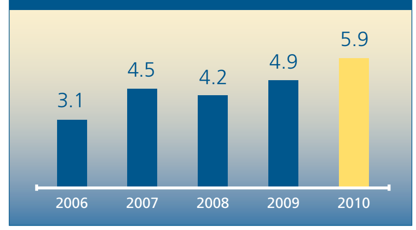
Dividends Paid per Common Share ($)



Dividend Payout Ratio (%)

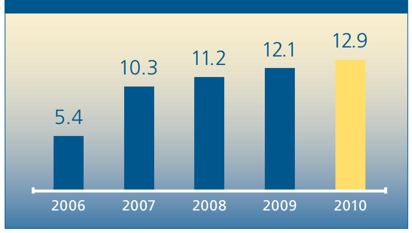


Market Capitalization ($B)

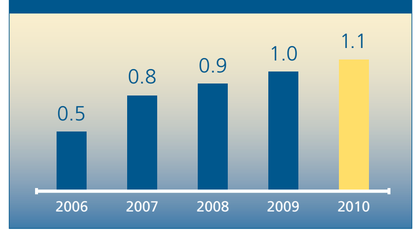


Return on Average Book Common Shareholders' Equity (%)

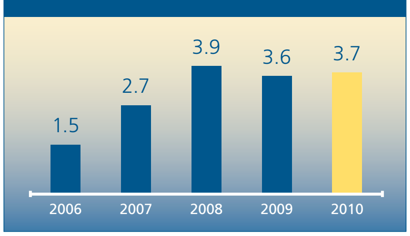
Assets ($B)



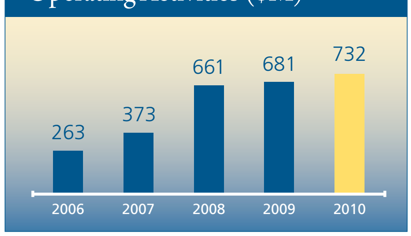
Capital Expenditures ($B)



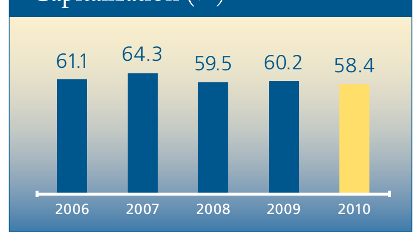
Revenue ($B)



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, 2010 unless otherwise indicated.

Regulated

Gas

Terasen (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) 2010	2011
Total	**949,000**	**1,480**	**1,421**	**193**	**253**	**5.2**	**3.4**	**130**	**9.50**	**9.50**

Electric

	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) (2)	Earnings ($M)	Allowed ROE (%) (3) 2010	2011
FortisAlberta	491,000	980	2,555	15,866	379	2.4	1.7	68	9.00	9.00 (4)
FortisBC	161,000	534	707	3,046	139	1.5	1.1	42	9.90	9.90
Newfoundland Power	243,000	572	1,206	5,419	78	1.2	0.9	35	9.00	8.38
Maritime Electric	74,000	182	207	1,033	26	0.4	0.3	12	9.75	9.75
FortisOntario	64,000	199	273	1,295	22	0.3	0.2	7	8.01/8.57 (5)	8.01/9.85 (5)
Belize Electricity (6)	77,000	296	81	426	23	0.2	0.2	2	– (7) (8)	– (7) (8)
Caribbean Utilities (9)	26,000	191	102	554	20	0.5	0.4	11	7.75–9.75 (7)	7.75–9.75 (7)
Fortis Turks and Caicos	9,000	106	31	170	29	0.2	0.2	10	17.50 (7) (10)	17.50 (7) (10)
Total	**1,145,000**	**3,060**	**5,162**	**27,809**	**716**	**6.7**	**5.0**	**187**		

(1) Includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies"

(2) Forecast mid-year 2011

(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. is 50 basis points higher.

(4) Interim pending finalization by the regulator

(5) Canadian Niagara Power 8.01%; Algoma Power 8.57% prior to December 1, 2010, 9.85% effective December 1, 2010

(6) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to consolidated earnings of Fortis based on the Corporation's 70% ownership interest.

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

(8) Allowed ROA to be settled once regulatory matters are resolved.

(9) 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 59% ownership interest.

(10) Amount provided under licence. ROA achieved in 2010 was materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Non-Regulated

Fortis Generation (1)

	Generating Capacity (MW)	Energy Sales (GWh)	Assets (3) ($B)	Earnings (4) ($M)	Capital Program ($M)
Total	**139**	**427**	**0.4**	**20**	**84**

Fortis Properties (2)

	Employees (#)	Assets ($B)	Earnings (4) ($M)	Capital Program ($M)
Total	**2,300**	**0.6**	**26**	**19**

(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 21 hotels across Canada

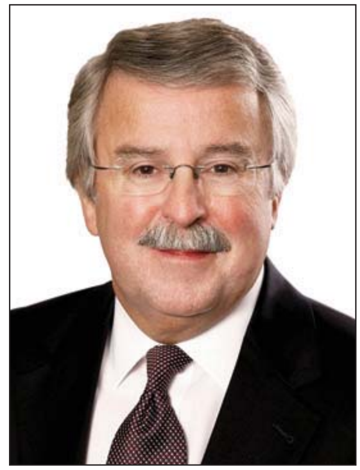
(3) Includes $108 million in "Other" non-regulated assets

(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2010

Information is for the fiscal year ended December 31, 2010 unless otherwise indicated.

Report to Shareholders


Stan Marshall, President and CEO, Fortis Inc.


David Norris, Chair of the Board, Fortis Inc.

For the 11th consecutive year, Fortis has delivered record earnings to our shareholders. Net earnings attributable to common equity shareholders were $285 million, $23 million higher than earnings of $262 million in 2009. Earnings per common share were $1.65 in 2010 compared to $1.54 in 2009.

Performance was driven by our Canadian Regulated Utilities and non-regulated hydroelectric generation operations. Tempering results year over year were lower earnings from Caribbean Regulated Electric Utilities and higher corporate expenses.

Fortis has raised its annualized dividend to common shareholders for 38 consecutive years, the record for a public corporation in Canada. Dividends paid per common share were $1.12 in 2010, up 7.7% from $1.04 paid per common share in the previous year. The dividend payout ratio was approximately 68% in 2010. Fortis increased its quarterly common share dividend to 29 cents, or $1.16 on an annualized basis, commencing with the first quarter dividend paid in 2011.

Over the past 10 years, Fortis delivered an average annualized total return to shareholders of 18%, the highest in our sector. The Corporation's average annualized total return also exceeded the S&P/TSX Capped Utilities Index and S&P/TSX Composite Index, which delivered average annualized performance of 11% and 7%, respectively, over the same period.

Platts, a leading global provider of energy information, named Fortis a Platts *Top 250 Global Energy Company* for 2010. Fortis earned a ranking of 11 as one of the *Top 50 Fastest-Growing Global Companies* in the Platts Top 250 Global Energy Company rankings, and a ranking of 3 overall in the *Fastest-Growing Americas Companies.*

Fortis is growing its non-regulated generation business in British Columbia with the construction of the $900 million 335-megawatt ("MW") Waneta Expansion hydroelectric generating facility on the Pend d'Oreille River. Last October Fortis entered into a partnership with Columbia Power Corporation and Columbia Basin Trust, two wholly owned entities of the Government of British Columbia, to construct the facility. Fortis owns a 51% controlling interest in the partnership, which has negotiated 40-year power sales agreements with BC Hydro and FortisBC for the energy and capacity, respectively, to be generated by the Waneta Expansion. Construction of the facility started in late 2010. Fortis will operate and maintain the Waneta Expansion when it comes into service expected in spring 2015. 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.

For the second consecutive year, our capital program surpassed $1 billion, reaching a record approximate $1.1 billion in 2010. The US$53 million 19-MW hydroelectric generating facility at Vaca in Belize was commissioned last March and completes the three-phase hydroelectric development of the Macal River. The facility is expected to increase annual energy production from the Macal River by 80 gigawatt hours ("GWh") to 240 GWh, an improvement of approximately 160 GWh since the Chalillo hydroelectric generating facility was commissioned in November 2005. Several significant capital projects in Canada continued throughout 2010 and are slated for completion in the coming months. FortisAlberta will substantially conclude its approximate $126 million multi-year Automated Meter Infrastructure Project, which involves the replacement of some 466,000 conventional meters, by the end of March. FortisBC is on track to complete its $106 million Okanagan Transmission Reinforcement Project, the largest capital project ever undertaken by the utility, by mid-2011. At Terasen Gas (Vancouver Island), construction of the $210 million liquefied natural gas storage facility is expected to be finished during the second quarter of 2011 and the facility is expected to be filled later in the year. In early 2012 we expect to complete the $110 million project underway at Terasen Gas to bring all customer care functions in-house with Company-owned call centres and a new customer information system.


The $900 million 335-MW Waneta Expansion Project is under construction.

Report to Shareholders

The most recent regulatory decisions received by our Canadian utilities provide continuing stability in 2011. Customer rates have been set effective January 1, 2011 for our four largest utilities. The allowed rate of return on common shareholder's equity ("ROE") for 2011 at Terasen Gas and FortisBC is 9.5% and 9.9%, respectively – unchanged from each utility's allowed ROE for 2010. The allowed ROE for 2011 at Newfoundland Power decreased to 8.38% from 9.0% as a result of the operation of the ROE automatic adjustment formula. The interim allowed ROE at FortisAlberta has been established at 9.0%, pending the outcome of a regulatory proceeding underway to review capital structure and finalize the ROE for 2011.

Construction of the $210 million Terasen Gas (Vancouver Island) liquefied natural gas storage facility is nearing completion.

In the first half of 2011, Terasen, FortisBC and FortisAlberta expect to file cost of service rate applications for 2012 and 2013. FortisAlberta is also participating in a process sponsored by the Alberta Utilities Commission ("AUC") to determine whether performance-based rate-setting ("PBR") should be applied to distribution utilities in Alberta as early as 2012. The AUC has not made a final decision on moving to PBR. Regulatory challenges are ongoing in Belize where Belize Electricity has sought judicial review of several regulatory decisions.

The integration of our regulated electric and gas utilities in British Columbia was initiated mid-year. FortisBC and Terasen Gas have combined assets of $6.7 billion and planned capital expenditures of $1.7 billion over the next five years. One management structure assures an integrated focus and strategy in the delivery of energy to our customers.

The Terasen Gas companies delivered earnings of $130 million, up $13 million from $117 million for 2009. Approximately $9 million of the improvement in earnings year over year was due to the regulator-approved reversal in 2010 of a provision taken in 2009 for the Whistler Pipeline Conversion Project cost overrun. Earnings also increased as a result of higher allowed ROEs at the Terasen Gas companies effective July 1, 2009 and an increase in the deemed common equity component of the total capital structure at Terasen Gas effective January 1, 2010.

Earnings at Canadian Regulated Electric Utilities were $164 million, up $15 million from $149 million for 2009. Excluding the favourable one-time $3 million corporate tax adjustment at FortisOntario in 2009, earnings were $18 million higher year over year. The increase was driven by overall growth in electrical infrastructure investment, the increase in the allowed ROE at FortisBC effective January 1, 2010, customer growth at FortisAlberta, increased electricity sales at Newfoundland Power, and improved performance at FortisOntario due to the first full year of earnings' contribution from Algoma Power and lower effective corporate income taxes. Earnings in 2010, however, reflected additional operating expenses of $1 million after tax at Newfoundland Power associated with restoration work following Hurricane Igor, the impact of a weather-related decrease in electricity sales at FortisBC and lower net transmission revenue at FortisAlberta.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which we operate and the leading service provider within our service areas.

Caribbean Regulated Electric Utilities contributed $23 million to earnings compared to $27 million for 2009. The decrease was largely due to the unfavourable impact of foreign currency translation and the inability of Belize Electricity to earn a fair and reasonable return in its difficult regulatory environment. In 2010 the utility contributed just $1.5 million to earnings of Fortis whereas, in the course of normal operations, it would be expected to contribute approximately $10 million annually. Results for 2010 also reflect low sales growth, due to persistent challenging economic conditions in the region and the negative effect on air conditioning load of cooler-than-normal temperatures experienced on Grand Cayman in the second half of 2010. Annualized electricity sales growth for the segment was 0.9% in 2010 compared to 2% in 2009.

Non-Regulated Fortis Generation contributed $20 million to earnings, up $4 million from 2009, mainly attributable to increased hydroelectric production in Belize associated with the commissioning of the 19-MW Vaca facility last March and higher rainfall, as well as lower finance charges. The growth in earnings was adversely impacted by the expiry of the water rights in April 2009 at the Rankine hydroelectric generating facility in Ontario.

Fortis Properties delivered earnings of $26 million, up $2 million from 2009, mainly due to lower effective corporate income taxes.


Fortis utilities serve 2,100,000 gas and electricity customers.

Corporate and other expenses were $78 million compared to $71 million for 2009. The increase was due to dividends associated with the $250 million First Preference Shares, Series H issued in January 2010 and business development costs incurred in 2010, partially offset by lower finance charges.

Fortis and its four largest utilities continue to have strong investment-grade credit ratings. Fortis is 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, significant reduction in external debt at Terasen Inc. and the Corporation's demonstrated ability to acquire and integrate stable utility businesses financed on a conservative basis.

Fortis and its utilities raised $525 million in long-term debt in 2010. In December Fortis privately placed 10-year US$125 million and 30-year US$75 million notes bearing interest at 3.53% and 5.26%, respectively. Proceeds from the notes were used to refinance indebtedness under the Corporation's committed credit facility related to amounts borrowed to repay maturing debt and for general corporate purposes. In the fourth quarter of 2010, FortisAlberta, Terasen Gas (Vancouver Island) and FortisBC issued 40-year $125 million 4.8%, 30-year $100 million 5.2% and 40-year $100 million 5.0% unsecured debentures, respectively. Proceeds from the debentures were used mainly to repay borrowings under the utilities' committed credit facilities incurred to finance their capital expenditure programs.


Capital work in 2010 included construction of the Benvoulin substation in Kelowna, British Columbia.

Fortis has consolidated credit facilities of $2.1 billion, of which $1.4 billion was unused at year-end 2010. Approximately $2 billion of the total credit facilities are committed facilities, most of which have maturities in 2012 and 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25%. As at December 31, 2010, the Corporation's long-term debt maturities and repayments are expected to average approximately $250 million annually over the next five years.

Strong investment-grade credit ratings, ample credit facilities and relatively low debt maturities provide Fortis and its subsidiaries with the flexibility to access debt capital markets at attractive rates.

We extend our appreciation and congratulations to our employees for another successful year. We express our gratitude to the Board of Directors for your continuing guidance and support.

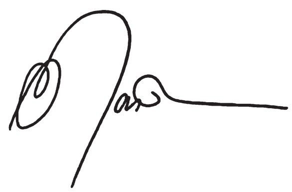
There is much work to be done. We expect to spend about $1.2 billion on our capital program in 2011 and near $5.5 billion over the next five years, driven by investment in infrastructure at our regulated utilities in western Canada and the Waneta Expansion Project. This investment will continue to drive growth in earnings and dividends.

Building on this organic growth, we will continue to pursue acquisitions of regulated electric and natural gas utilities in the United States and Canada that will add value for our shareholders, ever mindful that the priority of Fortis is to meet our obligation to serve our customers.

The 70-room expansion of the Holiday Inn Express Kelowna was completed in February 2010.

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.

In Memoriam

Fortis was saddened by the passing of Chair, Geoffrey Hyland, in November. All of us at Fortis have a tremendous amount of gratitude for the leadership, guidance and business acumen Geoff provided. He joined the Fortis Inc. Board of Directors in 2001 and was appointed Chair of our Board in 2008. He also served as a Director of FortisOntario. Geoff was well respected and highly regarded as both a colleague and a friend.

Following Geoff's passing, the Board of Directors appointed David Norris Chair of the Board.

Management Discussion and Analysis

Dated March 2, 2011

FORWARD-LOOKING INFORMATION

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2010 Consolidated Financial Statements and Notes thereto included in the Fortis Inc. ("Fortis" or the "Corporation") 2010 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 the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected total capital cost for the construction of the 335-megawatt Waneta Expansion hydroelectric generating facility and its expected completion date; organic earnings' growth for the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta and FortisBC; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the expectation that the Corporation and its utilities will continue to have reasonable access to capital in the near to medium terms; the expected 2% growth in electricity sales for 2011 at the Corporation's regulated utilities in the Caribbean; the expected average annual energy production from the Macal River in Belize; the expected timing of the close of the sale of the joint-use poles at Newfoundland Power; consolidated forecast gross capital expenditures for 2011 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 subsidiaries will be able to source the cash required to fund their 2011 capital expenditure programs; expected consolidated long-term debt maturities and repayments in 2011 and on average annually over the next five years; no material increase in consolidated interest expense and/or fees associated with renewed and extended credit facilities is expected in 2011; expected earnings' contribution from Belize Electricity to the consolidated earnings of Fortis in the course of normal operations; 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 2011; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; the expectation that Fortis will become a U.S. Securities and Exchange Commission Issuer by December 31, 2011; the expected impact of the transition to United States generally accepted accounting principles; and the expectation of an increase in consolidated defined benefit net pension cost for 2011. 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 operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no material capital project and financing cost overrun or delay related to the construction of the Waneta Expansion hydroelectric generating facility; no significant decline in capital spending in 2011; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; 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 and foreign exchange rates; no significant variability in interest rates; 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 and fuel supply; the continued ability to fund defined benefit pension plans; the absence of 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; maintenance of information technology infrastructure; 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; operating and maintenance risks; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas and fuel supply; defined benefit pension plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; the risk of transition to new accounting standards that do not recognize the impact of rate regulation; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits River Hydro Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations; and human resources. 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, 2010.*

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.

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CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three 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 primarily in Atlantic Canada. In 2010 the Corporation's electricity distribution systems met a combined peak demand of 5,162 megawatts ("MW") and its gas distribution system met a peak day demand of 1,421 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. The Corporation is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets have a combined generating capacity of 139 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and allow the pursuit of 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 serves to help offset corporate holding company expenses, mainly 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

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI").

TGI is the largest distributor of natural gas in British Columbia, serving more than 846,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving more than 100,000 residential, commercial and industrial customers.

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

TGWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service to approximately 2,600 residential and commercial customers.

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 491,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 161,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC 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 243,000 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 74,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and, as of October 2009, 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. ("Grimsby Power"), three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America, serving more than 77,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70% controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 26,000 customers. The Company has an installed generating capacity of 151 MW. Fortis holds an approximate 59% controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

c. *Fortis Turks and Caicos:* Includes 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 approximately 9,000 customers. The Company has a combined diesel-powered generating capacity of 57 MW.

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 indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario:* Includes six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls expired on April 30, 2009, at the end of a 100-year term.

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 plants 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 ("Newfoundland Hydro") under a 30-year power purchase agreement ("PPA") expiring in 2033. Effective February 12, 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership. For a further discussion of the Exploits Partnership, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia and the 335-MW Waneta hydroelectric generating facility ("Waneta Expansion"), which is being constructed. The Walden hydroelectric power plant 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 direct 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 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 stations, 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 indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties: Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 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 Terasen Inc. ("Terasen") and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen 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 Terasen holds a 30% interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. The financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

CORPORATE VISION AND STRATEGY

The principal business of Fortis 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. The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably at the lowest reasonable cost 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. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, Fortis pursues profitable growth through acquisitions focusing on regulated utilities in the United States and Canada. The acquisition of Terasen in May 2007, which almost doubled the size of the Corporation's assets, provides Fortis with a platform to acquire larger-sized regulated utilities. The primary focus is investor-owned U.S.-based utilities, due to the limited number of opportunities to acquire investor-owned regulated gas and electric utility assets in Canada. The non-utility business operations of Fortis support the Corporation's utility growth and acquisition strategy. Fortis Properties is expected to continue to grow in size and profitability, providing flexibility in financial and tax planning to the Corporation not generally possible with utilities due to regulatory and public policy constraints.

While there were no acquisitions by Fortis in 2010, the Corporation participated in a process for the acquisition of a large regulated electric utility in the United States in which Fortis was unsuccessful. Business development costs of approximately $4 million net of tax were incurred in 2010 in relation to this process.

In October 2010 Fortis, in partnership with CPC/CBT, concluded definitive agreements to construct the 335-MW Waneta Expansion at an estimated cost of $900 million. For further information refer to the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

In October 2009 FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for an aggregate purchase price of $75 million. Algoma Power is a regulated electric distribution utility serving approximately 12,000 customers in the District of Algoma in Ontario.

In June 2009 FortisOntario acquired a 10% interest in Grimsby Power for approximately $1 million. Grimsby Power is a regulated electric distribution utility serving approximately 10,000 customers in a service territory in close proximity to FortisOntario's operations in Fort Erie.

In April 2009 Fortis Properties acquired the 214-room Holiday Inn Select Windsor in Ontario for approximately $7 million.

KEY TRENDS AND RISKS

Allowed Rates of Return on Common Shareholders' Equity: The chart below highlights the trend in the allowed rates of return on common shareholders' equity ("ROE") at each of the Corporation's four largest regulated utilities.

Regulator-Approved Allowed ROEs

(%)	2007	2008	2009	2010	2011
TGI	8.37	8.62	8.47/9.50 (1)	9.50 (1)	9.50 (1)
FortisAlberta	8.51	8.75	9.00 (2)	9.00 (2)	9.00 (2)
FortisBC	8.77	9.02	8.87	9.90 (3)	9.90 (3)
Newfoundland Power	8.60	8.95	8.95	9.00 (3)	8.38 (4)

(1) Set by the regulator at 9.50%, effective July 1, 2009
(2) Set by the regulator for 2009, 2010 and on an interim basis for 2011
(3) Set by the regulator effective January 1, 2010
(4) Based on the operation of the formulaic ROE automatic adjustment mechanism

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 the Terasen Gas companies and FortisBC and the suspension of the mechanism at FortisAlberta. An ROE automatic adjustment mechanism is in effect at Newfoundland Power for, at a minimum, 2011 and 2012.

The use of automatic adjustment mechanisms to calculate allowed ROEs on an annual basis 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 on changes in long-term Canada bond rates. As long-term interest 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.

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, 2010, regulated utility assets comprised 92% of total assets (December 31, 2009 – 93%) and regulated utility assets in western Canada comprised 76% of total regulatory assets (December 31, 2009 – 75%). Organic earnings' growth from the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta and FortisBC. Since they were acquired in May 2004, the average rate bases of FortisAlberta and FortisBC have grown 124%.

Integration of Terasen and FortisBC: In 2010 the Terasen Gas companies and FortisBC, both operating in British Columbia and regulated by the British Columbia Utilities Commission ("BCUC"), began the process of integrating the Companies with one Chief Executive Officer leading both businesses and one Board of Directors providing oversight. This approach ensures an integrated focus and strategy in the delivery of energy to customers. In 2011 the Companies will continue to build an integrated platform to operate the businesses. For further information refer to the "Subsequent Event" section of this MD&A.

Caribbean Operating Environment: Regulated assets in the Caribbean region comprised 8% of the Corporation's total regulated assets as at December 31, 2010 (December 31, 2009 – 8%). Generally, the regulated rate of return on rate base assets ("ROA") in the Caribbean is higher than in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. However, the allowed ROAs at Caribbean Utilities and Belize Electricity were lowered beginning in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Prior to the global financial crisis that occurred during 2008 and 2009, economic growth had been strong in the Corporation's service territories in the Caribbean; however, the resultant economic downturn had an unfavourable impact on sales growth in 2009 and 2010 and is expected to continue to have a negative effect on electricity sales in 2011. Additionally, the Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

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. With regulated utilities in eight different jurisdictions, Fortis has significant regulatory expertise. 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. However, regulatory challenges continued at Belize Electricity during 2010 and a decision on the judicial challenge of the 2008 regulatory decision is expected in the first quarter of 2011.

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 40 years. As at December 31, 2010, approximately 81% of the Corporation's consolidated long-term debt and capital lease obligations 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 $2.1 billion in credit facilities, of which approximately $1.4 billion was unused as at December 31, 2010. 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 2011.

Dividend Increases: Common share dividend payments increased to $1.12 per share in 2010. A 3.6% increase in the quarterly common share dividend to 29 cents, effective the first quarter of 2011, from 28 cents translates into an annualized dividend of $1.16 and extends the Corporation's record of annual common share dividend increases to 38 consecutive years, the longest record of any public corporation in Canada. Fortis expects that its significant capital program will continue to drive growth in earnings and dividends.

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. With only 0.5% of the world's population, Canada accounts for about 2% of the world's GHG emissions, as per Scotia Capital's July 2010 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. The electricity sector in Canada is responsible for 16% of the country's GHG emissions, according to Environment Canada's National Inventory Report 1990–2008. The most significant impact for Fortis with respect to GHG emissions legislation will pertain to the Terasen Gas companies 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 the distribution only of electricity. Additionally, all in-house generating capacity at FortisBC 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 Corporation's 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, renewables are likely to be the fastest growing source of energy in the next decade. 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 next 20 years are likely to see renewable energy sources taking a larger percentage share of power generation and will lay the groundwork for a more significant shift to lower-carbon and carbon-free energy sources in the future.

The Waneta Expansion is an example of a clean renewable energy source and is expected to have an annual energy output of 675 gigawatt hours ("GWh") when it comes into service.

TGI is one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings. For example, TGI recently received approval from the BCUC for a new renewable natural gas program, on a limited basis, for an initial two-year period. An equivalent of 10% of the subscribed customers' natural gas requirements will be sourced from local renewable energy projects feeding gas supply into the TGI network. As part of this program, TGI has received approval to activate two projects that will upgrade raw biogas into biomethane, which will be added to TGI's distribution system. 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) requires Maritime Electric to supply 15% of its annual energy sales from renewable sources. With the recent 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 and sold to Maritime Electric from renewable energy sources, principally wind. The Government of PEI intends to install 30 MW of wind turbines on PEI by January 1, 2013, with a view to sell the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, scheduled for completion in PEI on or about January 1, 2012, will be purchased by the Government of PEI and, in turn, sold to Maritime Electric.

New Accounting Standards: Fortis is required to adopt a new set of accounting standards effective January 1, 2012. Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011. Qualifying entities with rate-regulated activities, however, were allowed a 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"). Fortis elected for the deferral but has developed and initiated a plan to adopt United States generally accepted accounting principles ("US GAAP") instead, effective January 1, 2012. US GAAP allows for the continued application of rate-regulated accounting and the associated recognition of regulatory assets and liabilities, which the Corporation feels best reflects the effect that rate regulation has on the Corporation's consolidated financial position and results of operations. For a complete discussion on the project plan Fortis has initiated to adopt US GAAP, refer to the "Future Accounting Changes" section of this MD&A.

For a complete discussion of the Corporation's business risks, refer to the "Business Risk Management" section of this MD&A.

FINANCIAL HIGHLIGHTS

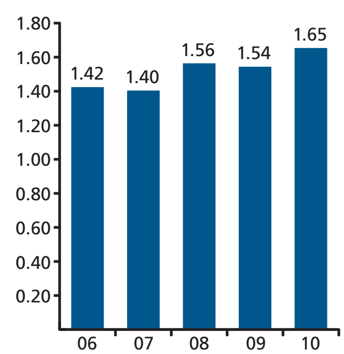
For the Years Ended December 31	**2010**	2009	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**285**	262	23
Basic Earnings per Common Share *($)*	**1.65**	1.54	0.11
Diluted Earnings per Common Share *($)*	**1.62**	1.51	0.11
Weighted Average Number of Common Shares Outstanding *(millions)*	**172.9**	170.2	2.7
Revenue *($ millions)*	**3,664**	3,643	21
Cash Flow from Operating Activities *($ millions)*	**732**	681	51
Dividends Paid per Common Share *($)*	**1.12**	1.04	0.08
Return on Average Book Common Shareholders' Equity *(%)*	**8.8**	8.4	0.4
Total Assets *($ millions)*	**12,903**	12,139	764
Gross Capital Expenditures *($ millions)*	**1,073**	1,024	49

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings per Common Share: Fortis achieved net earnings attributable to common equity shareholders of $285 million in 2010, up $23 million from earnings of $262 million in 2009. Earnings increased 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 Terasen Gas companies and FortisBC from July 1, 2009 and January 1, 2010, respectively, as well as an increase in the deemed equity component of the total capital structure ("equity component") at TGI from January 1, 2010; (iii) customer growth at FortisAlberta; and (iv) electricity sales growth at Newfoundland Power. The improvement in earnings was also attributable 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, due to 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.

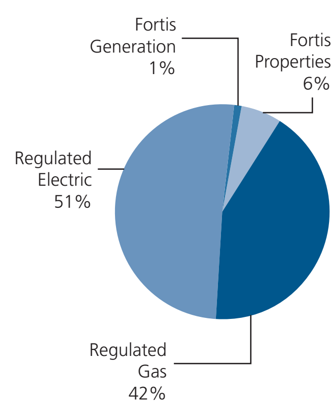
Basic earnings per share were $1.65 in 2010 compared to $1.54 in 2009, mainly due to growth in earnings year over year.

Revenue: Revenue was $3,664 million for 2010, up $21 million from revenue of $3,643 million for 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 increase was 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 due to warmer average temperatures.

Basic Earnings per Common Share *($)*



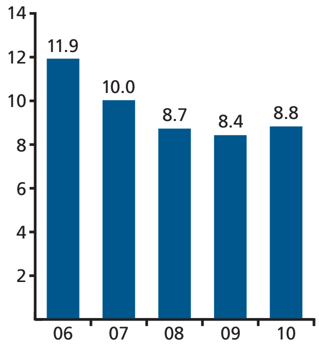
Revenue [(1)]
(year ended December 31, 2010)



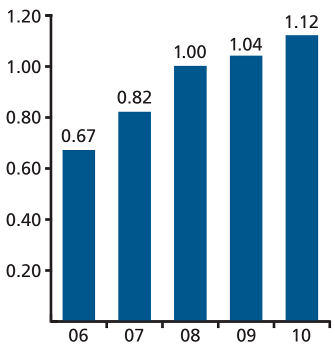
[(1)] Excludes Corporate and Other

Management Discussion and Analysis

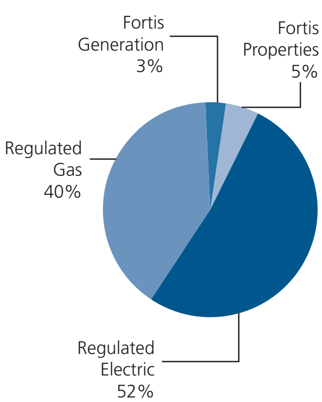
Return on Average Book Common Shareholders' Equity *(%)*



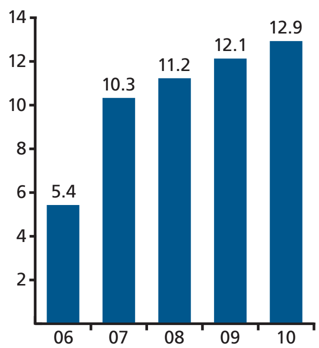
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2010)



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



Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity was 8.8% in 2010 compared to 8.4% in 2009. The increase was largely related to higher net earnings attributable to common shareholders.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $732 million for 2010, up $51 million from $681 million for 2009. The increase was driven by: (i) higher earnings; (ii) the collection from customers of increased amortization costs, mainly at the Terasen Gas companies, as approved by the regulators; (iii) favourable changes in the Alberta Electric System Operator ("AESO") charges deferral account at FortisAlberta; and (iv) a decrease in the amount of corporate taxes paid at Newfoundland Power. The increase was partially offset by unfavourable working capital changes at the Terasen Gas companies reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers year over year.

Dividends: Dividends paid per common share increased to $1.12 in 2010, up 7.7% from $1.04 in 2009. Fortis increased its quarterly common share dividend 3.6% to 29 cents from 28 cents, commencing with the first quarter dividend paid on March 1, 2011. The Corporation's dividend payout ratio was 67.9% in 2010 compared to 67.5% in 2009.

Total Assets: Total assets increased 6.6% to approximately $12.9 billion at the end of 2010 compared to approximately $12.1 billion at the end of 2009. The increase reflected the Corporation's continued investment in energy systems, driven by the capital expenditure programs at the Terasen Gas companies, FortisAlberta and FortisBC and the commencement of construction of the non-regulated Waneta Expansion in British Columbia. The increase was partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets.

Gross Capital Expenditures: During 2010 consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,073 million, up $49 million from $1,024 million in 2009. Total capital investment at the regulated utilities in western Canada in 2010 was approximately $771 million, representing approximately 72% of total gross capital expenditures. Much of the capital investment was driven by customer growth, the need to enhance the reliability and efficiency of energy systems and improve customer service. The larger capital projects during 2010 included the continued construction of the liquefied natural gas ("LNG") storage facility at TGVI, the continued implementation of the Customer Care Enhancement Project at TGI, the installation of Automated Meter Infrastructure ("AMI") technology at FortisAlberta and the Okanagan Transmission Reinforcement Project at FortisBC. Construction of the non-regulated Waneta Expansion commenced late in 2010. For a further discussion of the Waneta Expansion, refer to the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Financings: During 2010 Fortis and its regulated utilities raised $525 million in long-term debt. In December 2010 Fortis privately placed 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 7.40% senior unsecured debentures that matured in October 2010 and for general corporate purposes. At the subsidiary level, FortisAlberta issued 40-year $125 million 4.80% unsecured debentures in October; TGVI issued 30-year $100 million 5.20% unsecured debentures in December; and FortisBC issued 40-year $100 million 5.00% unsecured debentures in December. Proceeds from the long-term debt issues at the regulated utilities were mainly used to repay indebtedness under credit facilities incurred primarily in support of capital spending.

SEGMENTED RESULTS OF OPERATIONS

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31

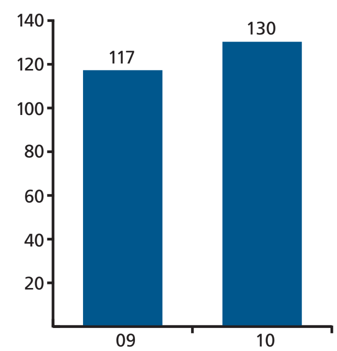
($ millions)	**2010**	2009	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**130**	117	13
Regulated Electric Utilities – Canadian			
FortisAlberta	**68**	60	8
FortisBC	**42**	37	5
Newfoundland Power	**35**	32	3
Other Canadian Electric Utilities [(1)]	**19**	20	(1)
	164	149	15
Regulated Electric Utilities – Caribbean	**23**	27	(4)
Non-Regulated – Fortis Generation [(2)]	**20**	16	4
Non-Regulated – Fortis Properties [(3)]	**26**	24	2
Corporate and Other	**(78)**	(71)	(7)
Net Earnings Attributable to Common Equity Shareholders	**285**	262	23

[(1)] Includes Algoma Power from October 2009, the date of acquisition
[(2)] Results for 2009 reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009, when the Rankine water rights expired at the end of a 100-year term. Results reflect contribution from the Vaca hydroelectric generating facility in Belize from March 2010 when the facility was commissioned.
[(3)] Includes the results of the Holiday Inn Select Windsor from April 2009, the date of acquisition

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2010 regulated earnings in Canada and the Caribbean represented approximately 87% (2009 – 88%) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 92% of the Corporation's total assets as at December 31, 2010 (December 31, 2009 – 93%).

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



Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2010 were $130 million (2009 – $117 million), which represented approximately 41% of the Corporation's total regulated earnings (2009 – 40%). Regulated Gas Utilities – Canadian assets were approximately $5.2 billion as at December 31, 2010 (December 31, 2009 – $5.0 billion), which represented approximately 44% of the Corporation's total regulated assets as at December 31, 2010 (December 31, 2009 – 44%).

Terasen Gas Companies

Gas Volumes by Major Customer Category

Years Ended December 31

(TJ)	**2010**	2009	Variance
Core – Residential and Commercial	**113,635**	125,238	(11,603)
Industrial	**5,259**	6,038	(779)
Total Sales Volumes	**118,894**	131,276	(12,382)
Transportation Volumes	**60,363**	60,067	296
Throughput Under Fixed Revenue Contracts	**13,765**	15,887	(2,122)
Total Gas Volumes	**193,022**	207,230	(14,208)

Factors Contributing to Gas Volumes Variance

Unfavourable

- Lower average gas consumption by residential, commercial and industrial customers, as a result of warmer average temperatures in 2010 compared to 2009
- Lower volumes under fixed revenue contracts, mainly due to reduced demand resulting from a large customer changing its gas supply requirements from peak demand to emergency demand

Net customer additions were approximately 9,400 for 2010 compared to 8,200 for 2009. Customer additions increased year over year due to increased building activity.

The Terasen Gas companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or for the transportation only of natural gas.

As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and energy supply costs from those forecast to set customer gas rates do not materially affect earnings.

Financial Highlights

Years Ended December 31

($ millions)	**2010**	2009	Variance
Revenue	**1,547**	1,663	(116)
Energy Supply Costs	**863**	1,022	(159)
Operating Expenses	**288**	268	20
Amortization	**108**	102	6
Finance Charges	**113**	121	(8)
Corporate Taxes	**45**	33	12
Earnings	**130**	117	13

Factors Contributing to Revenue Variance

Unfavourable

- Lower average gas consumption by residential and commercial customers
- Lower commodity cost of natural gas charged to customers

Favourable

- The increase in customer delivery rates, effective January 1, 2010, which mainly reflected: (i) the impact of the increase in the allowed ROE to 9.50% from 8.47% for TGI and to 10.00% for each of TGVI and TGWI from 9.17% and 8.97%, respectively, for a full year in 2010 compared to half a year in 2009; (ii) the increase in the equity component for TGI to 40% from 35%, effective January 1, 2010; and (iii) higher regulator-approved operating expenses and amortization costs recoverable from customers. The increase in the allowed ROEs for the Terasen Gas companies was effective July 1, 2009.

Factors Contributing to Earnings Variance

Favourable

- The increase in customer delivery rates, effective January 1, 2010, as discussed above for the revenue variance
- Lower finance charges, due to lower average credit facility borrowings
- The favourable $9 million year-over-year impact of the regulator-approved reversal in the third quarter of 2010 of most of the project cost overrun ($5 million pre-tax, $4 million after tax) related to the conversion of Whistler customer appliances from propane to natural gas, which was previously provided for and expensed in the fourth quarter of 2009 ($6 million pre-tax, $5 million after tax)

Unfavourable

- Higher operating expenses due to: (i) increased labour and employee-benefit costs; (ii) new initiatives agreed to in the regulator-approved Negotiated Settlement Agreement ("NSA") related to 2010 and 2011 revenue requirements resulting in higher planned maintenance and operating activities in 2010 compared to 2009; (iii) the expensing of asset removal costs to operating expenses, effective January 1, 2010, as a result of the NSA; and (iv) lower capitalized overhead costs, due to a reduction in the capitalization rate, also as a result of the NSA. The asset removal costs and higher expensed overhead costs were approved for collection in customer delivery rates. Prior to 2010 asset removal costs were recognized against accumulated amortization.
- Increased amortization costs due to higher amortization rates and continued investment in utility capital assets. Amortization rates for 2010 were determined and approved by the regulator upon review of a recent depreciation study. The increase in amortization costs is being collected in customer delivery rates.
- Higher effective corporate income taxes, mainly due to higher non-deductible expenses in 2010 compared to 2009, partially offset by a lower statutory income tax rate

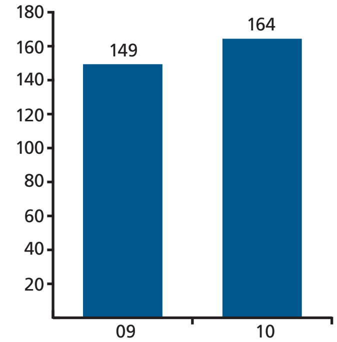
Outlook: The allowed ROEs for the Terasen Gas companies for 2011 remain unchanged from 2010 at 9.50% for TGI and 10.00% for TGVI and TGWI. Customer delivery rates at the Terasen Gas companies for 2011 have been approved by the regulator, effective January 1, 2011.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies is provided in the "Regulatory Highlights" section of this MD&A. A summary of forecast gross capital expenditures for 2011 for the Terasen Gas companies is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2010 were $164 million (2009 – $149 million), which represented approximately 52% of the Corporation's total regulated earnings (2009 – 51%). Regulated Electric Utilities – Canadian assets were approximately $5.8 billion as at December 31, 2010 (December 31, 2009 – $5.3 billion), which represented approximately 48% of the Corporation's total regulated assets as at December 31, 2010 (December 31, 2009 – 48%).

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



FortisAlberta

Financial Highlights

Years Ended December 31	2010	2009	Variance
Energy Deliveries [(1)] *(GWh)*	**15,866**	15,865	1
($ millions)			
Revenue	**388**	331	57
Operating Expenses	**141**	132	9
Amortization	**126**	94	32
Finance Charges	**54**	50	4
Corporate Tax Recoveries	**(1)**	(5)	4
Earnings	**68**	60	8

[(1)] Excludes energy deliveries to transmission-connected customers

Factors Contributing to Energy Deliveries Variance

Favourable

- Higher energy deliveries to residential, commercial and oil and gas customers, mainly associated with an increase in the number of customers

Unfavourable

- Decreased energy deliveries to farm and irrigation customers, mainly due to lower average consumption resulting from relatively milder temperatures and increased rainfall, partially offset by an increase in the number of customers
- Decreased energy deliveries to other industrial customers, mainly due to lower average consumption resulting from the impact of unfavourable economic conditions, and a reduction in the number of customers

The total number of customers at FortisAlberta increased approximately 11,000 from 2009, reaching approximately 491,000 as at December 31, 2010.

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

- Accrued electricity rate revenue combined with a 7.5% average increase in base customer electricity rates, effective January 1, 2010, associated with the 2010-2011 regulatory rate decision. The customer rate revenue accrual and rate increase were primarily due to ongoing investment in electrical infrastructure, and higher regulator-approved amortization costs, operating expenses and finance charges recoverable from customers.
- Customer growth

Unfavourable

- Lower net transmission revenue of approximately $5 million. Effective January 1, 2010, as a result of the 2010-2011 regulatory rate decision, all transmission costs and revenue are deferred to be recovered from, or refunded to, customers in future rates.

Collection of the rate revenue accrual began with new final customer rates and riders, effective January 1, 2011, as approved by the regulator.

Factors Contributing to Earnings Variance

Favourable

- The increase in electricity distribution rate revenue related to ongoing investment in electrical infrastructure, customer growth and higher regulator-approved expenses recoverable from customers.

Unfavourable

- Increased amortization costs associated with higher overall amortization rates, as approved in the 2010-2011 regulatory rate decision, and continued investment in utility capital assets, partially offset by the impact of the commencement, in 2010, of the capitalization of amortization for vehicles and tools used in the construction of other assets, as approved by the regulator
- Increased operating expenses, mainly due to higher general operating expenses and higher internal labour costs
- Higher finance charges, due to higher debenture borrowings in support of FortisAlberta's significant capital expenditure program and the impact of an increase in interest rates on credit facility borrowings, partially offset by lower average credit facility borrowings and increased capitalized allowance for funds used during construction
- Lower net transmission revenue, for the same reason as for the revenue variance discussed above
- Lower corporate tax recoveries, due to lower future income tax recoveries associated with changes in net customer deferrals and a favourable adjustment to current income taxes of approximately $2 million during the second quarter of 2009

Outlook: FortisAlberta's interim allowed ROE of 9.00% for 2011 is subject to change pending the outcome of a proceeding initiated by the regulator to finalize the allowed ROE for 2011. Customer rates at FortisAlberta for 2011 have been approved by the regulator, effective January 1, 2011.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta is provided in the "Regulatory Highlights" section of this MD&A. A summary of FortisAlberta's forecast gross capital expenditures for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

FortisBC

Financial Highlights

Years Ended December 31	2010	2009	Variance
Electricity Sales *(GWh)*	**3,046**	3,157	(111)
($ millions)			
Revenue	**266**	253	13
Energy Supply Costs	**73**	72	1
Operating Expenses	**73**	70	3
Amortization	**41**	37	4
Finance Charges	**32**	32	–
Corporate Taxes	**5**	5	–
Earnings	**42**	37	5

Factors Contributing to Electricity Sales Variance

Unfavourable

- Lower consumption, primarily due to unfavourable weather conditions

Favourable

- Customer growth

Factors Contributing to Revenue Variance

Favourable

- A 6.0% increase in customer electricity rates, effective January 1, 2010, mainly reflecting an increase in the allowed ROE to 9.90% for 2010, up from 8.87% for 2009, and ongoing investment in electrical infrastructure
- A 2.9% increase in customer electricity rates, effective September 1, 2010, as a result of the flow through to customers of increased power purchase costs charged by BC Hydro
- Increased performance-based rate-setting ("PBR") incentive adjustments receivable from customers
- Higher pole attachment revenue

Unfavourable

- The 3.5% decrease in electricity sales

Factors Contributing to Earnings Variance

Favourable

- The increase in customer electricity rates, effective January 1, 2010
- Increased PBR incentive adjustments
- Lower effective corporate income taxes, due to higher deductions from income for income tax purposes compared to accounting purposes in 2010 versus 2009, and a lower statutory income tax rate

Unfavourable

- Higher energy supply costs associated with the impact of higher average prices for purchased power
- Increased water fees and property taxes, and higher operating and maintenance costs due to increased labour costs and general inflationary increases, partially offset by an increase in capitalized overhead costs
- Increased amortization costs associated with continued investment in utility capital assets
- Decreased electricity sales
- Lower earnings' contribution from non-regulated operating, maintenance and management services, primarily due to higher operating costs

Outlook: FortisBC's allowed ROE of 9.90% for 2011 remains unchanged from 2010. Customer rates for 2011 have been approved by the regulator, effective January 1, 2011.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC is provided in the "Regulatory Highlights" section of this MD&A. A summary of FortisBC's forecast gross capital expenditures for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Newfoundland Power

Financial Highlights

Years Ended December 31	**2010**	2009	Variance
Electricity Sales *(GWh)*	**5,419**	5,299	120
($ millions)			
Revenue	**555**	527	28
Energy Supply Costs	**358**	346	12
Operating Expenses	**62**	52	10
Amortization	**47**	45	2
Finance Charges	**36**	35	1
Corporate Taxes	**16**	16	–
	36	33	3
Non-Controlling Interests	**1**	1	–
Earnings	**35**	32	3

Factors Contributing to Electricity Sales Variance

Favourable

- Customer growth and higher average consumption

Factors Contributing to Revenue Variance

Favourable

- An average 3.5% increase in customer electricity rates, effective January 1, 2010, mainly reflecting an increase in the allowed ROE to 9.00% for 2010, up from 8.95% for 2009; ongoing investment in electrical infrastructure; and higher regulator-approved expenses, including pension costs, recoverable from customers
- The 2.3% increase in electricity sales

Factors Contributing to Earnings Variance

Favourable

- The average 3.5% increase in customer electricity rates, effective January 1, 2010
- Increased electricity sales
- Lower effective corporate income taxes, due to a reduction in statutory income tax rates and higher deductions from income for income tax purposes compared to accounting purposes in 2010 versus 2009

Unfavourable

- Increased energy supply costs associated with the Company's hydroelectric generating facilities
- Higher pension costs, inflation and wage increases
- Incremental operating costs of approximately $1.5 million incurred in the third quarter of 2010 as a result of Hurricane Igor, which impacted over half of the Company's service territory
- Increased conservation, retirement and severance expenses, partially offset by lower regulatory costs and higher capitalized overhead costs
- Increased amortization costs associated with continued investment in utility capital assets
- Higher finance charges associated with interest expense on the $65 million 6.606% bonds issued in May 2009

Outlook: Newfoundland Power's allowed ROE is 8.38% for 2011, down from 9.00% for 2010, as a result of the operation of the ROE automatic adjustment mechanism. Customer rates for 2011 have been approved by the regulator, effective January 1, 2011.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power is provided in the "Regulatory Highlights" section of this MD&A. A summary of Newfoundland Power's forecast gross capital expenditures for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Other Canadian Electric Utilities (1)

Financial Highlights

Years Ended December 31	**2010**	2009	Variance
Electricity Sales *(GWh)*	**2,328**	2,195	133
($ millions)			
Revenue	**331**	285	46
Energy Supply Costs	**215**	183	32
Operating Expenses	**45**	38	7
Amortization	**23**	19	4
Finance Charges	**21**	19	2
Corporate Taxes	**8**	6	2
Earnings	**19**	20	(1)

(1) Includes Maritime Electric and FortisOntario. FortisOntario includes financial results of Algoma Power from October 8, 2009, the date of acquisition.

Factors Contributing to Electricity Sales Variance

Favourable

- Higher electricity sales at Algoma Power, mainly due to contribution for a full year in 2010 compared to three months in 2009. Algoma Power was acquired by FortisOntario in October 2009.

Factors Contributing to Revenue Variance

Favourable

- Higher revenue of approximately $27 million from Algoma Power, mainly due to a full year of revenue contribution in 2010 compared to three months in 2009 and an average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- An increase at Maritime Electric, effective August 1, 2010, in the base amount of energy-related costs being expensed and collected from customers and recognized in revenue through the base rate component of customer billings
- Increases in the base component of customer electricity distribution rates at Fort Erie, Gananoque and Port Colborne in Ontario, effective May 1, 2009 and May 1, 2010

Factors Contributing to Earnings Variance

Unfavourable

- A one-time favourable adjustment of approximately $3 million to future income taxes related to prior periods recognized during the fourth quarter of 2009 at FortisOntario

Favourable

- Earnings' contribution from Algoma Power increased $1.3 million, primarily due to a full year of earnings' contribution in 2010 and the impact of the average 3.8% customer electricity rate increase, effective December 1, 2010.
- Lower finance charges at Maritime Electric, due to lower short-term borrowing rates and the repayment of maturing $15 million first mortgage bonds in May 2010 that carried a 12% interest rate
- Lower effective corporate income taxes at FortisOntario, excluding the one-time $3 million corporate tax adjustment in 2009, due to higher deductions from income for income tax purposes compared to accounting purposes in 2010 versus 2009

Outlook: Maritime Electric's allowed ROE for 2011 of 9.75% remains unchanged from 2010. Largely reflecting lower power purchase costs, customer rates were reduced, effective March 1, 2011, at which time a two-year rate freeze commenced.

Algoma Power's allowed ROE for 2011 is 9.85% and customer rates have been approved by the regulator effective December 1, 2010. The allowed ROE for Canadian Niagara Power for 2011 remains unchanged at 8.01%.

Electricity distribution rates for Canadian Niagara Power customers have been approved by the Ontario Energy Board ("OEB") for the period May 1, 2010 through April 30, 2011 and an application for customer rates, effective May 1, 2011, has been filed with the OEB.

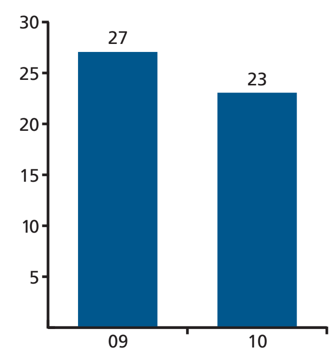
In February 2011 FortisOntario and First Nations' Lake Huron Anishinabek Transmission Company Inc. ("LHATC") entered into a memorandum of understanding ("MOU") for a joint venture to develop, construct and operate regulated electricity transmission projects in Ontario. FortisOntario will hold a minimum 51% interest, with LHATC having the rights to acquire up to a 49% equity interest, in the joint venture. The MOU is in response to the OEB's new Framework for Transmission Project Development Plans and the significant investment required in Ontario's transmission system to build additional capacity, as identified by the Ontario Power Authority, to accommodate new renewable energy supply and upgrade the aging transmission infrastructure.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Maritime Electric and FortisOntario is provided in the "Regulatory Highlights" section of this MD&A. A summary of forecast gross capital expenditures for Other Canadian Electric Utilities for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2010 was $23 million (2009 – $27 million), which represented approximately 7% of the Corporation's total regulated earnings (2009 – 9%). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2010 (December 31, 2009 – $0.9 billion), which represented approximately 8% of the Corporation's total regulated assets as at December 31, 2010 (December 31, 2009 – 8%).

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



Financial Highlights [(1)]

Years Ended December 31	**2010**	2009	Variance
Average US:CDN Exchange Rate [(2)]	**1.03**	1.13	(0.10)
Electricity Sales *(GWh)*	**1,150**	1,140	10
($ millions)			
Revenue	**335**	339	(4)
Energy Supply Costs	**201**	192	9
Operating Expenses	**48**	54	(6)
Amortization	**36**	37	(1)
Finance Charges	**17**	16	1
Corporate Taxes	**1**	2	(1)
	32	38	(6)
Non-Controlling Interests	**9**	11	(2)
Earnings	**23**	27	(4)

(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

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

Factors Contributing to Electricity Sales Variance

Favourable

- Customer growth at Belize Electricity
- Incremental load associated with a new system-connected medical facility and condominium complex in the Turks and Caicos Islands
- In July 2010 Fortis Turks and Caicos achieved a record peak demand of 31 MW.

Unfavourable

- Decreased air conditioning load, as a result of lower average temperatures experienced on Grand Cayman during the second half of 2010, most pronounced during the month of December
- Reduced residential customer base at Fortis Turks and Caicos, due to construction workers leaving the Turks and Caicos Islands
- Tempered growth due to continuing challenging economic conditions in the region

Factors Contributing to Revenue Variance

Unfavourable

- Approximately $33 million 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
- The unfavourable approximate $1.5 million year-over-year impact of the reversal of the Court of Appeal judgment at Fortis Turks and Caicos related to a customer-rate-classification matter

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel
- An overall 0.9% increase in electricity sales
- A 2.4% increase in base customer electricity rates at Caribbean Utilities, effective June 1, 2009

Factors Contributing to Earnings Variance

Unfavourable

- Approximately $3 million associated with unfavourable foreign currency translation
- Higher operating expenses at Belize Electricity, excluding the impact of foreign exchange, mainly due to increased legal fees associated with continued regulatory challenges
- Higher finance charges, excluding the impact of foreign exchange, mainly associated with interest expense on the US$40 million 7.5% unsecured notes issued in May 2009 and July 2009 at Caribbean Utilities, and lower capitalized allowance for funds used during construction, combined with higher interest expense on regulatory liabilities at Belize Electricity
- Higher amortization costs, excluding the impact of foreign exchange, mainly associated with continued investment in utility capital assets
- The favourable impact on energy supply costs in 2009, due to a change in the methodology for calculating the cost of fuel recoverable from customers at Fortis Turks and Caicos
- The unfavourable approximate $1.5 million year-over-year impact of the reversal of the Court of Appeal judgment at Fortis Turks and Caicos related to a customer-rate-classification matter

Favourable

- Excluding the impact of foreign exchange, lower operating expenses at Caribbean Utilities due to an increased focus on capital projects in 2010, which changed the timing of certain maintenance activities, combined with higher capitalized overhead, and lower operating expenses at Fortis Turks and Caicos associated with a lower provision for bad debts
- Reduced generator maintenance costs at Fortis Turks and Caicos
- Increased electricity sales

Outlook: Electricity sales growth at the Corporation's regulated utilities in the Caribbean is expected to be approximately 2% for 2011, reflecting the expected continuation of the negative impact of challenging economic conditions on electricity consumption by customers in the Caribbean region.

Discussions are expected to continue between Fortis Turks and Caicos and the Governor of the Turks and Caicos Islands regarding the request by the utility for an external, independent review of the utility's Electricity Rate Review ("ERR") filing and the current rate-setting mechanism.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos is provided in the "Regulatory Highlights" section of this MD&A. A summary of forecast gross capital expenditures for Regulated Electric Utilities – Caribbean for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

NON-REGULATED

Non-Regulated – Fortis Generation [1]

Financial Highlights

Years Ended December 31	2010 [2]	2009 [3]	Variance
Energy Sales *(GWh)*	**427**	583	(156)
($ millions)			
Revenue	**36**	39	(3)
Energy Supply Costs	**1**	2	(1)
Operating Expenses	**9**	11	(2)
Amortization	**4**	5	(1)
Finance Charges	**–**	2	(2)
Corporate Taxes	**2**	3	(1)
Earnings	**20**	16	4

(1) Includes the results of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The reporting currency for financial results in Belize and Upper New York State is the US dollar.

(2) Results reflect contribution from the Vaca hydroelectric generating facility in Belize from March 2010 when the facility was commissioned.

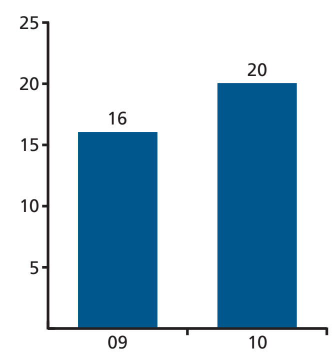
(3) Results reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009, when the Rankine water rights expired at the end of a 100-year term.

Factors Contributing to Energy Sales Variance

Unfavourable

- The expiration on April 30, 2009 of the water rights of the Rankine hydroelectric generating facility in Ontario. Energy sales during 2009 included approximately 215 GWh related to Rankine.
- Lower energy sales related to central Newfoundland operations. Energy sales for 2009 included 19 GWh related to central Newfoundland operations up until February 12, 2009, at which time the consolidation method of accounting for these operations was discontinued as a consequence of the actions of the Government of Newfoundland and Labrador related to expropriation of the assets of the Exploits Partnership. For a further discussion of the Exploits Partnership, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.
- Decreased production in Upper New York State, due to lower rainfall

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



Favourable

- Higher rainfall and the commissioning of the Vaca hydroelectric generating facility in Belize in March 2010. Production by the facility was 83 GWh during 2010.
- Higher production in British Columbia, due to higher rainfall

Factors Contributing to Revenue Variance

Unfavourable

- The loss of revenue subsequent to the expiration of the Rankine water rights on April 30, 2009
- The discontinuance of the consolidation method of accounting for the financial results of the Exploits Partnership on February 12, 2009
- Approximately $3 million unfavourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar
- Lower production in Upper New York State

Favourable

- Higher production in Belize and British Columbia
- A higher average annual wholesale market energy sales rate per megawatt hour ("MWh") in Upper New York State of US$43.12 for 2010 compared to US$38.54 for 2009
- A higher average annual energy sales rate per MWh in Ontario of $53.17 for 2010 compared to $34.43 for 2009. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract. Previously, energy was sold at market rates.

Factors Contributing to Earnings Variance

Favourable

- Higher production in Belize
- Reduced finance charges, excluding the impact of foreign exchange, as a result of higher interest revenue associated with inter-company lending to regulated operations in Ontario, partially offset by higher interest expense associated with inter-company lending to finance the construction of the Vaca hydroelectric generating facility. Capitalization of interest during the construction period ended with the commissioning of the facility in 2010.
- Higher average annual energy sales rates per MWh in Upper New York State and Ontario, partially offset by lower production in Upper New York State

Unfavourable

- The expiration of the Rankine water rights. Earnings' contribution associated with the Rankine hydroelectric generating facility was approximately $3.5 million during 2009.
- Approximately $2 million associated with unfavourable foreign currency translation

Outlook: The Vaca hydroelectric generating facility will contribute a full year of energy sales and earnings' contribution in 2011, with average annual energy production from the three hydroelectric generating facilities located on the Macal River in Belize forecast at 240 GWh. Construction of the non-regulated Waneta Expansion in British Columbia will continue in 2011. Further information on forecast non-regulated capital expenditures for 2011 is provided in the "Liquidity and Capital Resources – Capital Program" section of this MD&A.

Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2010**	2009	Variance
Hospitality Revenue	**160**	155	5
Real Estate Revenue	**66**	64	2
Total Revenue	**226**	219	7
Operating Expenses	**151**	146	5
Amortization	**18**	17	1
Finance Charges	**24**	22	2
Corporate Taxes	**7**	10	(3)
Earnings	**26**	24	2

Factors Contributing to Revenue Variance

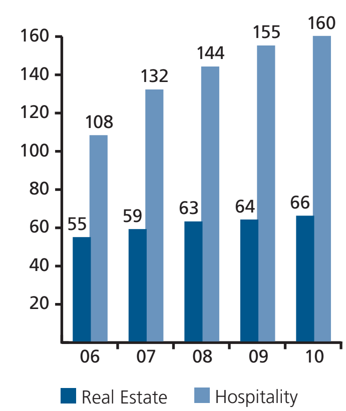
Favourable

- Revenue contribution from the Holiday Inn Select Windsor, acquired in April 2009, combined with higher revenue contribution from hotel properties in Atlantic Canada and central Canada, partially offset by lower revenue contribution from hotel properties in western Canada
- A 0.4% increase in revenue per available room ("RevPAR") at the Hospitality Division to $76.83 for 2010 from $76.55 for 2009. RevPAR increased due to an overall 1.8% increase in the average room rate, partially offset by an overall 1.4% decrease in hotel occupancy. Average room rates at operations in western Canada and Atlantic Canada increased. Hotel occupancy at operations in western Canada decreased, while occupancy at operations in central Canada and Atlantic Canada increased.
- Revenue growth in all regions of the Real Estate Division, with the most significant increases being in Newfoundland and Nova Scotia, mainly due to rent increases

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division to 94.5% as at December 31, 2010 from 96.2% as at December 31, 2009, mainly associated with operations in Newfoundland and New Brunswick

Fortis Properties
Revenue *($ millions)*



Factors Contributing to Earnings Variance

Favourable

- Lower effective corporate income taxes associated with lower statutory income tax rates and their effect of reducing future income tax liability balances
- Improved performance at the Real Estate Division, mainly due to rent increases
- Contribution from the Holiday Inn Select Windsor from April 2009
- Improved performance at hotel operations in Atlantic Canada, driven by increased RevPAR as discussed above

Unfavourable

- Lower performance at hotel operations in western Canada, due to the continued unfavourable impact of the economic downturn on occupancies in this region
- Increased finance charges, due to higher debt levels and interest rates

Outlook: Same-hotel revenue increased at Fortis Properties' Hospitality Division in 2010. Continued revenue growth will be challenged in 2011 due to economic conditions and increased supply in various markets.

The Real Estate Division is expected to produce stable results in 2011. 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 [1]

Financial Highlights

Years Ended December 31

($ millions)	**2010**	2009	Variance
Revenue	**30**	27	3
Operating Expenses	**16**	14	2
Amortization	**7**	8	(1)
Finance Charges [2]	**73**	79	(6)
Corporate Tax Recovery	**(16)**	(21)	5
	(50)	(53)	3
Preference Share Dividends	**28**	18	10
Net Corporate and Other Expenses	**(78)**	(71)	(7)

[1] Includes Fortis net corporate expenses, net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30% ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

[2] Includes dividends on preference shares classified as long-term liabilities

Factors Contributing to Net Corporate and Other Expenses Variance

Unfavourable

- Higher preference share dividends, due to the issuance of Five-Year Fixed Rate Reset First Preference Shares, Series H ("First Preference Shares, Series H") in January 2010
- Higher operating expenses, primarily due to business development costs incurred in 2010, partially offset by higher recovery of costs from subsidiary companies and lower non-regulated operating expenses at TES

Favourable

- Lower finance charges, excluding the impact of foreign exchange, due to the finalization of capitalized interest incurred to finance the Vaca hydroelectric generating facility during the period of construction, and the repayment of higher interest-bearing debt in 2010. The decrease was partially offset by interest expense on the 30-year $200 million 6.51% unsecured debentures issued in July 2009 and the impact of higher average credit facility borrowings. In October 2010 Fortis redeemed its $100 million 7.4% unsecured debentures and in April 2010 Terasen redeemed its $125 million 8.0% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility.
- A favourable foreign exchange impact of approximately $2.5 million associated with the translation of US dollar-denominated interest expense, due to the weakening of the US dollar relative to the Canadian dollar
- Increased revenue, due to interest income on higher inter-company lending at higher interest rates to Fortis Properties to finance the Company's maturing external debt

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 (%) 2009	2010	2011	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
TGI	BCUC	40 [(1)]	8.47 [(2)] /9.50 [(3)]	9.50	9.50	TGI: 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
TGVI	BCUC	40	9.17 [(2)] /10.00 [(3)]	10.00	10.00	ROEs established by the BCUC, effective July 1, 2009, as a result of a cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROEs were set using an automatic adjustment formula tied to long-term Canada bond yields.
TGWI	BCUC	40	8.97 [(2)] /10.00 [(3)]	10.00	10.00	Future Test Year
FortisBC	BCUC	40	8.87	9.90	9.90	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, effective January 1, 2010, as a result of a cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
FortisAlberta	Alberta Utilities Commission ("AUC")	41	9.00	9.00	9.00 [(4)]	COS/ROE ROE established by the AUC, effective January 1, 2009, as a result of a generic cost of capital decision in the fourth quarter of 2009. Previously, the allowed ROE was set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.95 +/– 50 bps	9.00 +/– 50 bps	8.38 +/– 50 bps	COS/ROE ROE for 2010 established by the PUB. Except for 2010, the allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year
FortisOntario	OEB					
	Canadian Niagara Power	40 [(5)]	8.01	8.01	8.01	Canadian Niagara Power – COS/ROE
	Algoma Power	50 [(6)] /40 [(7)]	8.57	8.57	9.85 [(7)]	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 2009, 2010 and 2011 Algoma Power – 2007 historical test year for 2009 and 2010; 2011 test year for 2011
				ROA		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	– [(8)]	– [(8)]	– [(8)]	Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	9.00 – 11.00	7.75 – 9.75	7.75 – 9.75	COS/ROA 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 Governor	N/A	17.50 [(9)]	17.50 [(9)]	17.50 [(9)]	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) Effective January 1, 2010. For 2009, the allowed common equity component was 35%.
(2) Pre-July 1, 2009
(3) Effective July 1, 2009
(4) Interim pending finalization by the AUC
(5) Effective May 1, 2010. For 2009, effective May 1, the allowed common equity component was 43.3%.
(6) Pre-December 1, 2009
(7) Effective December 1, 2010
(8) Allowed ROA to be settled once regulatory matters are resolved.
(9) Amount provided under licence. ROA achieved in 2009 and 2010 was materially lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI/TGVI/ TGWI	• TGI and TGWI review natural gas and propane commodity rates and mid-stream rates with the BCUC every three months 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 mid-stream resources, such as third-party pipeline or storage capacity. The commodity cost of natural gas and propane and mid-stream costs are flowed through to customers without markup. In November and December 2009 the BCUC approved: (i) NSAs pertaining to the 2010 and 2011 Revenue Requirements Applications for TGI and TGVI; (ii) an increase in TGI's equity component, effective January 1, 2010, to 40% from 35%; (iii) an increase in TGI's allowed ROE, effective July 1, 2009, to 9.50% from 8.47%; and (iv) an increase in the allowed ROE to 10.00% for each of TGVI and TGWI, effective July 1, 2009, from 9.17% and 8.97%, respectively. In its decision on the Return on Equity and Capital Structure Application, the BCUC maintained TGI as a benchmark utility for calculating the allowed ROE for certain utilities regulated by the BCUC. The BCUC also determined that the former automatic adjustment formula used to establish the ROE annually will no longer apply and the allowed ROEs as determined in the BCUC decision will apply until reviewed further by the BCUC. The BCUC-approved NSA for TGI did not include a provision to allow the use of a new PBR mechanism after the expiry, on December 31, 2009, of TGI's previous PBR agreement. The impact of the approved NSAs, the increase in the allowed ROEs, the higher equity component and the change in mid-stream costs at TGI resulted in an overall average increase in customer rates of 10%, effective January 1, 2010, for customers in the Lower Mainland, Fraser Valley, Interior, North and Kootenay service areas. Customer rates for TGVI's sales customers, however, will remain unchanged for the two-year period beginning January 1, 2010, as provided in the BCUC-approved NSA for TGVI. • In February 2010 the BCUC approved TGI's application for the insourcing of core elements of its customer care services and implementation of a new customer information system, upon the Company accepting a cost risk-sharing condition, whereby TGI would share equally with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost. • In December 2010 TGI filed an application with the BCUC to provide fuelling services through TGI owned and operated compressed natural gas and LNG fuelling stations. If approved, commercial customers will be able to safely and economically refuel their fleet vehicles on their own premises, at rates regulated by the BCUC, using stations provided by TGI. • In December 2010 TGI received approval from the BCUC for a new renewable natural gas program for an initial two-year period. In 2011 up to 24,000 residential customers will be able to subscribe to the program, paying an approximate $4 monthly premium to replace 10% of their natural gas supply with biomethane. The BCUC approval also allows TGI to implement agreements with Catalyst Power Inc. and the Columbia Shuswap Regional District to collect biogas from agricultural waste and a landfill site, respectively. • In December 2010 the Terasen Gas companies filed a report with the BCUC, as required, which included a study by an external consultant, engaged by the utilities, of alternative formulaic ROE automatic adjustment mechanisms used in North America. Based on the study, the Terasen Gas companies are not proposing to adopt a formulaic ROE automatic adjustment mechanism at this time. • TGI, TGVI and TGWI are considering an amalgamation of the three companies. An amalgamation would require an application to be approved by the BCUC and consent of the Government of British Columbia. While a decision to proceed with an amalgamation has not yet been made, the Terasen Gas companies are contemplating bringing forth an application during 2011. • In January 2011 TGI filed its review of the Price Risk Management Plan ("PRMP") objectives with the BCUC related to its gas commodity hedging plan and also submitted a 2011-2014 PRMP. An updated PRMP for TGVI is expected to be filed by April 2011. • Effective January 1, 2011 rates for residential customers in the Lower Mainland, Fraser Valley, Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and mid-stream costs. • The forecast mid-year rate base for 2011 for TGI and TGVI is $2.6 billion and $0.7 billion, respectively.
FortisBC	• In December 2009 the BCUC approved an NSA pertaining to FortisBC's 2010 Revenue Requirements Application. The result was a general customer electricity rate increase of 6.0%, effective January 1, 2010. The rate increase was primarily the result of the Company's ongoing investment in electrical infrastructure, increasing energy supply costs and the higher cost of capital. FortisBC's allowed ROE increased to 9.90%, effective January 1, 2010, from 8.87% in 2009 as a result of the BCUC decision to increase the allowed ROE of TGI, the benchmark utility in British Columbia. • In August 2010 FortisBC received BCUC approval for a 2.9% increase in customer rates, effective September 2010. The increase was due to higher power purchase costs being charged to the Company by BC Hydro. • In November 2010 FortisBC received Board of Directors' approval to enter into the Waneta Expansion Capacity Agreement to purchase capacity output from the 335-MW Waneta Expansion. The Waneta Expansion Capacity Agreement, which was accepted by the BCUC in September 2010, will allow FortisBC to purchase capacity for 40 years upon completion of the Waneta Expansion, which is anticipated in spring 2015. For further information refer to the "Liquidity and Capital Resources – Capital Program" section of this MD&A. • In December 2010 the BCUC approved an NSA pertaining to FortisBC's 2011 Revenue Requirements Application. 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 electrical infrastructure and the higher cost of capital. Customer rates for 2011 reflect an allowed ROE of 9.90%, unchanged from 2010. • In December 2010 FortisBC received BCUC approval of its 2011 Capital Expenditure Plan. Forecast gross capital expenditures for 2011 total approximately $99 million. • FortisBC's forecast mid-year rate base for 2011 is $1.1 billion.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta	• In November 2009 the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding ("2009 GCOC Decision") establishing a generic allowed ROE of 9.00% for 2009, 2010 and, on an interim basis, for 2011, for all Alberta utilities regulated by the AUC. The allowed ROE of 9.00% was up from the interim allowed ROE for 2009 of 8.51% for FortisAlberta. The ROE automatic adjustment formula will no longer apply until reviewed further by the AUC. The AUC also increased FortisAlberta's equity component to 41% from 37%, effective January 1, 2009. The $4.1 million favourable 2009 annual impact of the 2009 GCOC Decision was accrued as revenue in the fourth quarter of 2009 and is being collected in customer electricity rates in 2011. • In December 2009 the AUC approved, on an interim basis, an average 7.5% increase in FortisAlberta's base customer electricity distribution rates, effective January 1, 2010. • In July 2010 the AUC issued its decision on the Company's comprehensive two-year Distribution Tariff Application ("DTA") for 2010 and 2011, which was originally filed in June 2009. The Company reflected the impact of the decision, retroactive from January 1, 2010, in its third quarter results and has accrued the increased revenue requirements for collection in customer base distribution electricity rates in 2011 for billing implementation. The resulting required increase in customer rates reflects the Company's ongoing investment in electrical infrastructure to support customer growth and maintain and upgrade the electricity system, and higher expenses. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC requesting that CAREA be entitled to serve any new customer in the overlapping CAREA service area wishing to obtain electricity for use on property, and that FortisAlberta be restricted to, and shall provide, electricity distribution service in CAREA's service area only to a customer in that service area who is not being provided service by CAREA. FortisAlberta has intervened in the proceeding. • In December 2010 the AUC issued its decision on the Company's Compliance Filing, which incorporated the AUC's decision on the Company's 2010 and 2011 DTA. The December 2010 decision approved the Company's distribution revenue requirements of $346 million for 2010 and $368 million for 2011. New final distribution electricity rates and rate riders were also approved, effective January 1, 2011. • In its 2010 and 2011 DTA FortisAlberta had requested an update in the forecast capital cost of its AMI Project, bringing the total forecast project cost to $126 million (excluding the cost of the pilot program), up from an original total forecast project cost of $104 million. The AUC reached the conclusion, however, that the capital cost of the AMI Project of $104 million (excluding the pilot program) had formed part of the Company's 2008 and 2009 NSA that had been approved in 2008 and, therefore, did not approve the updated forecast. The Company filed a Review and Variance Application with the AUC and a Leave to Appeal with the Alberta Court of Appeal regarding this conclusion. The AUC issued its decision regarding the Review and Variance Application approving a hearing into the prudence of capital expenditures above $104 million. A proceeding has been initiated and will be in writing, with a decision expected in the second quarter of 2011. The Company's Leave to Appeal has been adjourned pending the determination of the Review and Variance. The Utilities Consumer Advocate filed with the Alberta Court of Appeal a Leave to Appeal request, which has similarly been adjourned. • The AUC issued a Notice of Commission-Initiated Proceeding in December 2010 to finalize the allowed ROE for 2011, review capital structure and consider whether a return to a formula-based approach for annually setting the allowed ROE, beginning in 2012, is warranted. In the absence of a formula-based approach, the AUC is expected to consider how the allowed ROE will be set for 2012. This proceeding will also consider additional matters associated with customer contributions. • The AUC has initiated a process to reform utility rate regulation in Alberta. The AUC has expressed its intention to apply a PBR formula to distribution service electricity rates. FortisAlberta is currently assessing PBR and will participate fully in the AUC process. The Company will submit a 2012 and 2013 COS Application in the first quarter of 2011 under the Uniform System of Accounts/Minimum Filing Requirements format in order to bridge the transition between COS and possible PBR regulation. • FortisAlberta's forecast mid-year rate base for 2011 is approximately $1.7 billion.
Newfoundland Power	• In December 2009 the PUB issued a decision on Newfoundland Power's 2010 General Rate Application ("2010 GRA") resulting in an overall average increase in customer electricity rates of approximately 3.5%, effective January 1, 2010. The rate increase reflected the impact of an increase in the allowed ROE to 9.00% from 8.95% in 2009, ongoing investment in electrical infrastructure and higher expenses, including pension costs. The PUB also ordered that Newfoundland Power's allowed ROE for each of 2011 and 2012 be determined using the ROE automatic adjustment formula. • In April 2010 the PUB approved the Company's application, as filed, to change the existing ROE automatic adjustment formula. Forecast long-term Canada Bond yields are now being used to determine the risk-free rate for calculating the forecast cost of equity used in the formula for 2011 and 2012. The previous approach used a 10-day observation of long-term Canada bond yields as the forecast risk-free rate. • Effective July 1, 2010 there was an overall average approximate 1.7% increase in electricity rates charged to Newfoundland Power customers. The increase was the result of the normal annual operation of the Rate Stabilization Plan of Newfoundland Hydro. Variances in the cost of fuel used to generate the electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to Newfoundland Power customers through the operation of the Rate Stabilization Plan. The increase in customer rates had no impact on Newfoundland Power's earnings. • In November 2010 the PUB approved Newfoundland Power's application to defer the recovery of expected increased costs of $2.4 million, due to expiring regulatory amortizations, in 2011.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• In November 2010 the PUB approved Newfoundland Power's 2011 Capital Budget Plan totalling approximately $73 million, before customer contributions. • In accordance with the operation of the ROE automatic adjustment formula, Newfoundland Power's allowed ROE has been reduced from 9.00% for 2010 to 8.38% for 2011. • In December 2010 the PUB approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for other post-employment benefit ("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 Canadian GAAP 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 practices for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011. • Newfoundland Power's forecast mid-year rate base for 2011 is $0.9 billion. • In December 2010 Newfoundland Power and Bell Aliant signed a new Support Structure Agreement, effective January 1, 2011, whereby Bell Aliant will buy back 40% of all joint-use poles and related infrastructure owned by Newfoundland Power for approximately $46 million. This transaction represents approximately 5% of Newfoundland Power's rate base. In 2001 Newfoundland Power purchased joint-use poles and related infrastructure from Bell Aliant (formerly Aliant Telecom Inc.) under a 10-year Joint-Use Facilities Partnership Agreement ("JUFPA") that expired December 31, 2010. Bell Aliant exercised the option to buy back these poles from Newfoundland Power. The Support Structure Agreement is subject to certain conditions, including PUB approval of the sale of 40% of the Company's joint-use poles, which must be met by both parties by June 30, 2011, or either party may choose to terminate. In the event of termination, the rights and recourses under the JUFPA will remain in effect for both parties. Newfoundland Power has filed an application with the PUB requesting approval of the transaction and expects the transaction to close in 2011. • As at December 31, 2010, Newfoundland Power recognized assets held for sale in the amount of approximately $45 million, which represented the estimated sales price less cost to sell the joint-use poles. The estimated sales price will be adjusted upon completion of a pole survey in 2011. Effective January 1, 2011, the Company is no longer receiving pole rental revenue from Bell Aliant. However, Newfoundland Power will be responsible for the construction and maintenance of Bell Aliant's support structure requirements throughout 2011. The Support Structure Agreement with Bell Aliant is not expected to materially impact Newfoundland Power's ability to earn a reasonable rate of return on its rate base in 2011. Newfoundland Power is currently working with Bell Aliant regarding the future operational and financial aspects of this transaction beyond 2011. The Company anticipates that the proceeds from this transaction will be used to pay down its credit facility borrowings and maintain its equity component at 45%. • The Company is currently assessing the requirement that it file an application with the PUB to recover expected increased costs in 2012.
Maritime Electric	• In July 2010 IRAC approved Maritime Electric's 2010/2011 Rate Application providing for: (i) an increase in the reference cost of energy in base electricity rates, effective August 1, 2010; (ii) the amortization of the replacement energy costs incurred during the refurbishment of the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") over the extended life of the unit; and (iii) an allowed ROE of 9.75% for 2010 and 2011, unchanged from 2009. • In November 2010 Maritime Electric entered into a PPA with NB Power for a five-year period commencing March 2011, which will result in lower and stable power purchase costs for customers over the period. • 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 will assume responsibility for the cost of replacement energy and 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. The Government of PEI will finance these costs, which will be recovered from customers beginning when Point Lepreau returns to service. 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, replacement energy costs incurred during the refurbishment period are being deferred by Maritime Electric and were approximately $47 million to the end of February 2011. The timing and terms of recovery of the deferred costs is subject to further review by a commission to be established by the Government of PEI. 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 subsequently collected from customers over a period to be established by the Government of PEI. As a result of the Accord, 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. • In December 2010 Maritime Electric received regulatory approval, as filed, of its 2011 Capital Budget totalling approximately $23 million, before customer contributions.
FortisOntario	• In April 2010 FortisOntario received Decisions and Orders from the OEB with respect to Third-Generation Incentive Rate Mechanism ("IRM") electricity distribution rate applications for harmonized rates for Fort Erie and Gananoque and rates for Port Colborne, effective May 1, 2010. In non-rebasing years, customer electricity rates are set using inflationary factors less an efficiency target under the OEB's Third-Generation IRM. The resulting increase in base electricity rates, effective May 1, 2010, was minimal, with an inflationary increase of 1.3%, partially offset by a 1.12% efficiency target. The approved customer electricity rates reflected an allowed ROE of 8.01% on an equity component of 40%.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In November 2010 FortisOntario filed Third-Generation IRM electricity distribution rate applications for Fort Erie, Gananoque and Port Colborne for customer rates effective May 1, 2011. The OEB will publish the applicable inflationary and productivity factors in the first quarter of 2011. Customer electricity rates will reflect an allowed ROE of 8.01% on an equity component of 40%. • FortisOntario intends to file a COS Application in April 2011 for harmonized electricity distribution rates for Fort Erie, Port Colborne and Gananoque, effective January 1, 2012, using a 2012 forward test year. • 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 reflect an approved allowed ROE of 9.85% on an equity component of 40%. The OEB approval resulted in a 2011 revenue requirement of $20 million, of which approximately $11 million will be recovered through the RRRP Program, with the remainder to be recovered through increased customer rates and charges. Through regulations relating to the RRRP Program, the average increase in the electricity delivery charge to customers, effective December 1, 2010, was 2.5%. The overall impact of the OEB rate decision on an average customer's electricity bill was an increase of 3.8%, including rate riders and other charges. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program; therefore, Algoma Power has agreed to consult with interveners 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 for other electric utilities in Ontario. Pending these consultations, Algoma Power will file for incentive rate-making for customer electricity distribution rates, effective January 1, 2012.
Belize Electricity	• Changes made in electricity legislation by the Government of Belize and the PUC, the PUC's June 2008 Final Decision on Belize Electricity's 2008/2009 Rate Application (the "June 2008 Final Decision") and the PUC's amendment to the June 2008 Final Decision, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. In response to an application from Belize Electricity, the Supreme Court of Belize issued an order in June 2010 prohibiting the PUC from carrying out any rate-setting review proceedings, changing any rates and taking any enforcement or penal steps against Belize Electricity until further order of the Supreme Court. • The evidentiary portion of the trial of Belize Electricity's appeal of the PUC's June 2008 Final Decision was heard in October 2010 with closing arguments completed in December 2010. A court decision on the matter is expected in the first quarter of 2011.
Caribbean Utilities	• In February 2010 the ERA approved Caribbean Utilities' 2010 Capital Investment Plan ("CIP") of US$21 million for non-generation installation expenditures. Additional generation needs are subject to a competitive bid process. • In May 2010 Caribbean Utilities submitted its annual RCAM calculations to the ERA as set out in the utility's T&D licence. The RCAM, which permits base electricity rates to move with inflation, yielded no rate adjustment as at June 1, 2010, as the slight inflation in the U.S. price index was offset by deflation in the Cayman Islands price index for calendar year 2009. • In November 2010 Caribbean Utilities filed its 2011-2015 CIP totalling approximately US$219 million. The 2011-2015 CIP was prepared upon the basis of the Company's application to the ERA for a delay in any new generation installation until there is more certainty in growth forecasts. In January 2011 the ERA provided general approval of the US$134 million of proposed non-generation installation expenditures in the CIP. The remaining US$85 million of the CIP related to new generation installation, which would be subject to a competitive bid process. The general approval of non-generation expenditures is subject to Caribbean Utilities providing additional information related to certain planned projects. Final approval of the CIP is expected during the first half of 2011.
Fortis Turks and Caicos	• In March 2010 Fortis Turks and Caicos submitted its 2009 annual regulatory filing outlining the Company's performance in 2009 and its capital expansion plans for 2010. • In March 2010 Fortis Turks and Caicos filed an ERR with the Ministry of Works, Housing and Utilities of the Government of the Turks and Caicos Islands in accordance with Section 34 of the *Electricity Ordinance*. The filing requested an average 7% increase in base customer electricity rates, effective May 31, 2010. The rate increase would have been the first rate increase implemented by Fortis Turks and Caicos since its inception. The objectives of the ERR included setting rates for the various classes of customers through an Allocated Cost of Service Study, introducing uniformity in the rate structure throughout the service territory of Fortis Turks and Caicos and enabling the utility to start to recover its December 31, 2009 accumulated regulatory shortfall in achieving its allowable profit. • In June 2010 Fortis Turks and Caicos received notice from the Governor of the Turks and Caicos Islands (the "Governor") that the Company's ERR filing had not been accepted because of concern about the impact that the proposed rate increase might have on key sectors of the Islands' economy. • In September 2010 Fortis Turks and Caicos received draft proposals and terms of reference from the Governor to review the Company's ERR filing. Management has acknowledged the Governor's proposed terms of reference and objectives, and has proposed that a jointly funded and identified outside independent consultant be engaged to conduct a review of the ERR filing and current rate-setting mechanism and make recommendations regarding both.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2010 and December 31, 2009.

Significant Changes in the Consolidated Balance Sheets between December 31, 2010 and December 31, 2009

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	60	The increase was primarily due to higher revenue accruals at FortisAlberta, and normal timing differences relating to the operation of the customer equal payment plan and the timing of collection of Harmonized Sales Tax rebates at the Terasen Gas companies.
Regulatory assets – current and long-term	125	The increase was driven by deferrals at the Terasen Gas companies associated with (i) a $45 million change in the fair market value of the natural gas derivatives; (ii) the draw down of the Commodity Cost Reconciliation Account and the Gas Cost Variance Account at TGI and TGVI, respectively, as amounts are being refunded to customers in current commodity rates; and (iii) the deferral of net losses on the disposal of utility capital assets, effective January 1, 2010, combined with the accrual of distribution rate revenue at FortisAlberta as a result of the 2010 and 2011 DTA. The increase was partially offset by a reduction in the Midstream Cost Reconciliation Account at TGI, as amounts collected in customer rates were in excess of actual mid-stream gas delivery costs, and a reduction in the AESO charges deferral account at FortisAlberta, as amounts related to 2008 were collected in customer rates in 2010.
Assets held for sale	45	The increase was due to the reclassification of amounts from utility capital assets resulting from the pending sale of joint-use poles from Newfoundland Power to Bell Aliant.
Utility capital assets	509	The increase primarily related to $1,008 million invested in electricity and gas systems, partially offset by amortization and customer contributions during 2010, the reclassification of joint-use poles to assets held for sale, as discussed above, and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets.
Intangible assets	38	The increase was driven by rights acquired by the Waneta Partnership associated with the non-regulated Waneta Expansion.
Short-term borrowings	(57)	The decrease reflected the repayment of short-term borrowings by TGI with proceeds from an equity injection from Fortis and by TGVI with proceeds from the $100 million debenture issue in December 2010. The decrease was partially offset by higher borrowings at Maritime Electric to finance $15 million of maturing long-term debt and at Caribbean Utilities to finance capital expenditures.
Accounts payable and accrued charges	101	The increase was driven by a $45 million change in the fair market value of the natural gas derivatives at the Terasen Gas companies and the reclassification from long-term other liabilities of TGVI's deferred payment, which comes due in 2011, associated with Terasen's acquisition of TGVI in 2002.
Dividends payable	51	The increase was due to the timing of the declaration of common share dividends for the first quarter of 2010.
Regulatory liabilities – current and long-term	53	The increase was mainly due to: (i) an increase in the Rate Stabilization Deferral Account at TGVI, reflecting the accumulation of over-recovered costs of providing service to customers during 2010; (ii) an increase in the provision for asset removal and site restoration costs at FortisAlberta; (iii) the 2010 AESO charges deferral account at FortisAlberta; and (iv) an increase in the Rate Stabilization Account at Belize Electricity, due to lower cost of fuel and purchased power compared to amounts collected in customer rates during 2010. The increase was partially offset by a reduction in the Revenue Stabilization Adjustment Mechanism account at TGI, as natural gas consumption volumes were lower than forecast during 2010.
Long-term debt and capital lease obligations (including current portion)	165	The increase was driven by the issuance of long-term debt, partially offset by regularly scheduled debt repayments, maturities and redemptions and the impact of foreign exchange on the translation of foreign currency-denominated long-term debt. The debt maturities and redemptions included the repayment of maturing $15 million 12% first mortgage bonds at Maritime Electric with proceeds from short-term borrowings; the redemption of the $125 million 8.0% Capital Securities at Terasen with proceeds from borrowings under the Corporation's committed credit facility; the repayment of maturing $100 million 7.4% unsecured debentures at Fortis with proceeds from borrowings under the Corporation's committed credit facility; and the repayment of approximately $50 million of maturing debt at Fortis Properties with proceeds from borrowings under the Corporation's committed credit facility.

Significant Changes in the Consolidated Balance Sheets between December 31, 2010 and December 31, 2009 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion) (cont'd)		The issuance of long-term debt, primarily to repay committed credit facility borrowings, short-term borrowings and maturing debt, was comprised of a $125 million debenture offering by FortisAlberta, a $100 million debenture offering by each of TGVI and FortisBC and a US$200 million private note offering by Fortis.
Future income tax liabilities – current and long-term	35	The increase was driven by tax timing differences related to capital expenditures at FortisAlberta and FortisBC.
Shareholders' equity	357	The increase was driven by the issuance of $250 million First Preference Shares, Series H in January 2010. The net proceeds were used to repay borrowings under the Corporation's committed credit facility and fund an equity injection into TGI. The remainder of the increase was due to net earnings attributable to common equity shareholders during 2010, less common share dividends, and the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans.
Non-controlling interests	39	The increase was driven by the 49% non-controlling interest in the Waneta Partnership.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2010 compared to 2009, followed by a discussion of the nature of the variances in cash flows year over year.

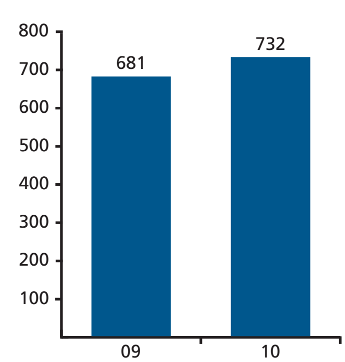
Summary of Consolidated Cash Flows

Years Ended December 31

($ millions)	**2010**	2009	Variance
Cash, Beginning of Year	**85**	66	19
Cash Provided by (Used in):			
Operating Activities	**732**	681	51
Investing Activities	**(991)**	(1,045)	54
Financing Activities	**283**	387	(104)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**–**	(4)	4
Cash, End of Year	**109**	85	24

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2010 was $51 million higher than in 2009. The increase was driven by: (i) higher earnings; (ii) the collection from customers of increased amortization costs, mainly at the Terasen Gas companies, as approved by the regulators; (iii) favourable changes in the AESO charges deferral account at FortisAlberta; and (iv) a decrease in the amount of corporate taxes paid at Newfoundland Power. The increase was partially offset by unfavourable working capital changes at the Terasen Gas companies reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers year over year.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2010 was $54 million lower than in the previous year. The decrease related to higher proceeds from the sale of utility capital assets, increased contributions in aid of construction and the acquisition of Algoma Power and the Holiday Inn Select Windsor in 2009. The decrease was partially offset by higher gross capital expenditures.

Gross capital expenditures in 2010 were $1,073 million, $49 million higher than in 2009. The increase related to the commencement of construction of the non-regulated Waneta Expansion late in 2010 and higher capital spending at FortisBC, partially offset by lower capital spending at FortisAlberta and at Caribbean Regulated Electric Utilities.

Financing Activities: Cash provided by financing activities in 2010 was $104 million lower than in the previous year. The decrease was due to higher common share dividends and a lower net increase in debt, partially offset by higher proceeds from the issuance of preference and common shares and higher advances from non-controlling interests.

Management Discussion and Analysis

Net repayment of short-term borrowings was $56 million in 2010 compared to net proceeds from short-term borrowings of $8 million for 2009. The decrease in cash associated with changes in short-term borrowings was driven by the Terasen Gas companies and FortisAlberta.

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 2010 compared to 2009 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2010**	2009	Variance
Terasen Gas Companies	**100** (1)	99 (2)	1
FortisAlberta	**124** (3)	222 (4) (5)	(98)
FortisBC	**99** (6)	104 (7)	(5)
Newfoundland Power	**–**	64 (8)	(64)
Caribbean Utilities	**–**	43 (9)	(43)
Corporate	**200** (10)	197 (11)	3
Total	**523**	729	(206)

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

(2) Issued February 2009, 30-year $100 million 6.55% unsecured debentures by TGI. The net proceeds were used to repay credit facility borrowings and repay $60 million 10.75% unsecured debentures that matured in June 2009.

(3) 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.

(4) Issued October 2009, 30-year $125 million 5.37% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(5) Issued February 2009, 30-year $100 million 7.06% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(6) 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.

(7) Issued June 2009, 30-year $105 million 6.10% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings, for general corporate purposes, including financing capital expenditures and working capital requirements, and to help repay $50 million 6.75% debentures that matured in July 2009.

(8) Issued May 2009, 30-year $65 million 6.606% first mortgage sinking fund bonds. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes, including financing capital expenditures.

(9) Issued May 2009 and July 2009, 15-year US$30 million 7.50% and US$10 million 7.50% unsecured notes, respectively. The net proceeds were used to repay short-term borrowings and finance capital expenditures.

(10) 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.

(11) Issued July 2009, 30-year $200 million 6.51% unsecured debentures. The net proceeds were used to repay, in full, the indebtedness outstanding under the Corporation's committed credit facility and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	**2010**	2009	Variance
Terasen Gas Companies	**–**	(62)	62
FortisBC	**(1)**	(55)	54
Newfoundland Power	**(5)**	(5)	–
Maritime Electric	**(15)**	–	(15)
Caribbean Utilities	**(15)**	(16)	1
Fortis Properties	**(59)**	(24)	(35)
Corporate	**(225)** (1)	–	(225)
Other	**(9)**	(10)	1
Total	**(329)**	(172)	(157)

(1) In April 2010 Terasen redeemed in full for cash its $125 million 8.0% 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)	**2010**	2009	Variance
Terasen Gas Companies	**–**	5	(5)
FortisAlberta	**1**	(99)	100
FortisBC	**(35)**	4	(39)
Newfoundland Power	**1**	(18)	19
Corporate	**41**	94	(53)
Total	**8**	(14)	22

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 issues are used to repay borrowings under the Corporation's committed credit facility.

Net proceeds associated with the issuance of common shares were $80 million in 2010 compared to $46 million in 2009, reflecting the impact of the Corporation's dividend reinvestment, stock option and share purchase plans. The dividend reinvestment plan currently provides participating common shareholders a 2% discount on the purchase of common shares, issued from treasury, with reinvested dividends.

In January 2010 Fortis completed a $250 million offering of 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 TGI.

Common share dividends paid in 2010 totalled $193 million, up $16 million from 2009. The increase 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 $1.12 in 2010 compared to $1.04 in 2009. The weighted average number of common shares outstanding was 172.9 million for 2010 compared to 170.2 million for 2009.

Preference share dividends increased $10 million year over year as a result of the dividends associated with the 10 million First Preference Shares, Series H that were issued in January 2010.

Contractual Obligations

Consolidated contractual obligations of Fortis with external third parties over the next five years and for periods thereafter, as of December 31, 2010, are outlined in the following table.

Contractual Obligations

As at December 31, 2010

($ 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)]	**5,669**	54	377	789	4,449
Brilliant Terminal Station [(2)]	**59**	3	5	5	46
Gas purchase contract obligations [(3)]	**555**	306	195	54	–
Power purchase obligations					
FortisBC [(4)]	**2,908**	44	89	81	2,694
FortisOntario [(5)]	**462**	47	97	101	217
Maritime Electric [(6)]	**245**	56	88	87	14
Belize Electricity [(7)]	**171**	18	37	42	74
Capital cost [(8)]	**446**	15	32	34	365
Operating lease obligations [(9)]	**134**	17	29	26	62
Joint-use asset and shared service agreements [(10)]	**65**	4	8	7	46
Defined benefit pension funding contributions [(11)]	**32**	14	13	2	3
Office lease – FortisBC [(12)]	**19**	2	3	3	11
Other [(13)]	**21**	5	9	6	1
Total	**10,786**	585	982	1,237	7,982

(1) In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments 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. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances, and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. 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 TGVI's approved capital structure, as will TGVI's rate base, which is used in determining

customer rates. The repayment criteria were met in 2009 and TGVI made a $4 million repayment on the loans during 2010 (2009 – $8 million). As at December 31, 2010, 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 TGVI 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. TGVI, however, estimates making payments under the loans of $24 million over 2012 and 2013, $20 million over 2014 and 2015 and $5 million in 2016.

(2) On July 15, 2003 FortisBC began operating the Brilliant Terminal Station ("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 will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

(3) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas 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, 2010.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and the Powerex Corp. ("Powerex") capacity agreement. 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 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 2010 FortisBC entered into a capacity agreement with Powerex, a wholly owned subsidiary of BC Hydro, for fixed-price winter capacity purchases through to February 2016 in an aggregate amount of approximately US$16 million. If FortisBC brings any new resources, such as capital or contractual projects, online prior to the expiry of this agreement, FortisBC may terminate this contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex.

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

(6) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. 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 the Point Lepreau and Dalhousie Generating Stations. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new international power line into the United States, and expires in November 2032.

(7) Power purchase obligations for Belize Electricity include a 15-year PPA, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity. In addition, two 15-year PPAs commenced in 2009 with Belize Cogeneration Energy Limited and Belize Aquaculture Limited to provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively.

(8) Maritime Electric has entitlement to approximately 6.7% and 4.7% of the output from the Dalhousie and Point Lepreau Generating Stations, respectively, for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units. The Company terminated the Dalhousie Generating Station agreement as of March 1, 2011.

(9) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro.

(10) 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 2015 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.

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

December 31, 2010 – Terasen (covering unionized employees) and FortisBC
December 31, 2011 – Newfoundland Power
December 31, 2012 – Terasen (covering non-unionized employees)

(12) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

(13) Other contractual obligations primarily include capital lease obligations, operating building leases and asset-retirement obligations ("AROs") at FortisBC.

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 customer requests and by large capital projects specifically approved by their respective regulatory authority. The consolidated capital program of the Corporation, including non-regulated segments, is forecast to be approximately $1.2 billion for 2011, which has not been included in the commitments 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 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, 2010, no such termination notice has been given by either party. As such, the contract is effectively renewed for 2011. The quantity of fuel to be purchased under the contract for 2011 is approximately 25 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 issues. 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, 2010 compared to December 31, 2009 is presented in the following table.

Capital Structure

As at December 31	**2010**		2009	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) (1)	**5,914**	**58.4**	5,830	60.2
Preference shares (2)	**912**	**9.0**	667	6.9
Common shareholders' equity	**3,305**	**32.6**	3,193	32.9
Total (3)	**10,131**	**100.0**	9,690	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 change in the capital structure was driven by the issuance of $250 million preference shares in January 2010, and increased common shares outstanding reflecting the impact of the Corporation's dividend reinvestment, share purchase and stock option plans. Proceeds from the issuance of long-term debt were partially offset by repayments of long-term debt, capital lease obligations and short-term borrowings during 2010.

Credit Ratings

The Corporation's credit ratings are as follows:

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

In December 2010 S&P confirmed the Corporation's long-term corporate and unsecured debt credit rating of A– (stable) and in October 2010 DBRS upgraded the Corporation's unsecured debt credit rating to A(low) from BBB(high). 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 and the significant reduction in external debt at Terasen, the Corporation's reasonable credit metrics, and its demonstrated ability and continued focus of acquiring and integrating stable regulated utility businesses financed on a conservative basis.

Capital 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. During 2010 approximately $96 million in maintenance and repairs was expensed compared to approximately $91 million during 2009.

Gross consolidated capital expenditures for the year ended December 31, 2010 were approximately $1.1 billion. A breakdown of gross capital expenditures by segment and asset category for 2010 is provided in the following table.

Gross Consolidated Capital Expenditures (1)

Year Ended December 31, 2010

($ millions)	Terasen Gas Companies	Fortis Alberta (2)	Fortis BC	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility (3)**	**Fortis Properties**	**Total**
Generation	–	–	18	6	2	**26**	**26**	**85**	**–**	**137**
Transmission	116	–	77	7	3	**203**	**6**	**–**	**–**	**209**
Distribution	86	267	31	56	40	**480**	**28**	**–**	**–**	**508**
Facilities, equipment, vehicles and other	39	99	9	5	1	**153**	**11**	**–**	**19**	**183**
Information technology	12	13	4	4	2	**35**	**1**	**–**	**–**	**36**
Total	253	379	139	78	48	**897**	**72**	**85**	**19**	**1,073**

(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 2010.

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

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

Gross consolidated capital expenditures of $1,073 million for 2010 were $25 million lower than $1,098 million forecast for 2010 as disclosed in the MD&A for the year ended December 31, 2009. A decrease in capital spending at the Terasen Gas companies largely due to: (i) a regulator-approved decrease in capitalized overhead costs; (ii) a shift in capital spending from 2010 to 2011 related to certain projects; and (iii) lower-than-forecast capital spending on alternative energy projects, combined with lower actual capital costs at FortisBC mainly due to prevailing market conditions coupled with a shift in capital spending from 2010 to 2011 for certain projects, was partially offset by increased capital spending at the Non-Regulated – Fortis Generation segment associated with the commencement of construction of the non-regulated Waneta Expansion late in 2010.

Gross consolidated capital expenditures for 2011 are expected to be approximately $1.2 billion. Planned capital expenditures are based on detailed forecasts of energy demand, weather and cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2011 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [(1)]

Year Ending December 31, 2011

($ millions)	Terasen Gas Companies	Fortis Alberta [(2)]	Fortis BC	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility** [(3)]	**Fortis Properties**	**Total**
Generation	–	–	19	9	2	**30**	**20**	**183**	**–**	**233**
Transmission	92	–	31	6	3	**132**	**10**	**–**	**–**	**142**
Distribution	105	286	31	50	35	**507**	**36**	**–**	**–**	**543**
Facilities, equipment, vehicles and other	67	119	14	4	2	**206**	**16**	**–**	**27**	**249**
Information technology	17	15	4	4	4	**44**	**1**	**–**	**–**	**45**
Total	281	420	99	73	46	**919**	**83**	**183**	**27**	**1,212**

(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 2011.

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

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

The percentage breakdown of 2010 actual and 2011 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows:

Gross Consolidated Capital Expenditures

Year Ended December 31

(%)	**Actual 2010**	Forecast 2011
Growth	**51**	47
Sustaining [(1)]	**29**	28
Other [(2)]	**20**	25
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 AMI and AESO transmission capital expenditures at FortisAlberta and the in-house Customer Care Enhancement Project at TGI

Significant capital projects for 2010 and 2011 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) **Company**	**Nature of project**	Pre-2010	**Actual 2010**	Forecast 2011	Forecast Post-2011	Expected Year of Completion
Terasen Gas Companies	LNG storage facility – Vancouver Island	118	**58**	34	–	2011
	Customer Care Enhancement Project	3	**30**	67	10	2012
	Fraser River South Bank South Arm Rehabilitation Project	9	**12**	14	–	2011
FortisAlberta	AMI technology	75	**37**	14	–	2011
	Pole Management Program	39	**21**	27	196	2019
FortisBC	Okanagan Transmission Reinforcement Project	29	**57**	20	–	2011
	Transmission Projects	83	**11**	–	15	2010/2015
	Generation Asset Upgrade and Life-Extension Program	30	**15**	15	4	2012
Fortis Turks and Caicos	Three new 9-MW diesel-powered generating units	–	**15**	8	13	2011/2016
Waneta Partnership	Waneta Expansion	–	**75**	182	643	2015

(1) Relates to utility capital asset and intangible asset expenditures combined with both capitalized interest and equity components of the allowance for funds used during construction

TGVI continues construction of the BCUC-approved LNG storage facility. Construction commenced during 2008 and is expected to be finished during the second quarter of 2011 and the facility is expected to be filled later in the year. The total capital cost of this project is estimated at approximately $210 million.

In February 2010 the BCUC approved TGI's application for the in-sourcing of core elements of its customer care services and implementation of a new customer information system, upon the Company accepting a cost risk-sharing condition, whereby TGI would share equally with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost. The Customer Care Enhancement Project is expected to be in place effective January 2012, for a total forecast project cost of approximately $110 million.

The Fraser River South Bank South Arm Rehabilitation Project was approved by the BCUC in March 2009 and involves the installation and replacement of underwater transmission pipeline crossings that are 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 is now expected to come into service in 2011, rather than in 2010 as originally expected, at an estimated total cost of approximately $35 million.

During 2010 FortisAlberta has continued with the replacement of conventional customer meters with AMI technology. The capital cost of the AMI Project is expected to be approximately $126 million (excluding the pilot program) and the project will be substantially completed by the end of March 2011. For further information related to this project, refer to the "Material Regulatory Decisions and Applications – FortisAlberta" section of this MD&A.

FortisAlberta has undertaken a pole management program to replace 80,000 vintage poles to prevent risk of failure due to age. Approximately $283 million is expected to be spent on this pole management initiative, which is slated to extend to 2019.

The FortisBC Okanagan Transmission Reinforcement Project, approved by the BCUC, commenced in 2009. The project relates 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. The total cost of the project is estimated at $106 million with expected completion by mid-2011.

Work continues on transmission and distribution systems at FortisBC. A new substation in the Central Kelowna area is currently forecast to be constructed between 2013 and 2015 to meet load growth and reliability. This project is estimated to cost approximately $15 million and is subject to regulatory approval.

Since 1998 hydroelectric generating facilities at FortisBC have been subject to a Generation Asset Upgrade and Life-Extension Program. Newly installed equipment is projected to enhance reliability and efficiency, while the use of standardized components is expected to reduce future maintenance and capital expenditures. Approximately $19 million, as approved by the BCUC, is expected to be spent during 2011 and 2012.

Fortis Turks and Caicos has an agreement with a supplier to purchase two diesel-powered generating units each with a capacity of 9 MW. The first unit was delivered in May 2010 and came into service in January 2011 and the second unit was delivered in February 2011. An additional 9-MW unit is forecast for delivery in 2016. The total cost of the three units is estimated at approximately $36 million.

In October 2010 the Corporation, in partnership with CPC/CBT, concluded definitive agreements to construct the 335-MW Waneta Expansion at an estimated cost of approximately $900 million. The facility is sited adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. CPC/CBT are both 100% owned entities of the Government of British Columbia. Fortis owns a controlling 51% interest in the Waneta Partnership and will operate and maintain the Waneta Expansion when it comes into service, which is expected in spring 2015. SNC-Lavalin was awarded a contract for approximately $590 million to design and build the Waneta Expansion. Construction began in November 2010 and approximately $75 million was incurred on this capital project in 2010. The Waneta Expansion will be included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, (and associated capacity required to deliver such energy) for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement which has been executed. The surplus capacity, equal to 234 MW on an average annual basis, will be sold to FortisBC under a long-term capacity purchase agreement, which was accepted by the BCUC in September 2010.

Over the next five years, consolidated gross capital expenditures are expected to approach $5.5 billion. Approximately 63% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC. Approximately 20% and 17% of the capital spending is expected to be incurred at the regulated gas utilities and at non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval.

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 issues.

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 its 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 2011 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be near $60 million in 2011 and to average approximately $250 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 a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $5 million (BZ$9 million) as at December 31, 2010.

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 $58 million as at December 31, 2010 (December 31, 2009 – $59 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 "Critical Accounting Estimates – Contingencies" section of this MD&A.

Except for the debt at Belize Electricity and the Exploits Partnership, as described above, Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2010 and are expected to remain compliant in 2011.

Credit Facilities

As at December 31, 2010, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which approximately $1.4 billion was unused, including $435 million unused under the Corporation's $600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25% of these facilities.

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' consolidated financial results in 2011. Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities in 2012 and 2013.

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, 2010**	Total as at December 31, 2009
Total credit facilities	645	1,451	13	**2,109**	2,153
Credit facilities utilized:					
Short-term borrowings	–	(351)	(7)	**(358)**	(415)
Long-term debt (including current portion)	(165)	(53)	–	**(218)**	(208)
Letters of credit outstanding	(1)	(122)	(1)	**(124)**	(100)
Credit facilities unused	479	925	5	**1,409**	1,430

As at December 31, 2010 and 2009, 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, 2009 to December 31, 2010 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2010 are detailed in Note 28 to the 2010 Consolidated Financial Statements.

In February 2010 Maritime Electric renewed its $50 million unsecured committed revolving credit facility, which matures annually in March. During the second quarter of 2010, Maritime Electric increased its unsecured committed revolving credit facility by $10 million.

In April 2010 FortisBC amended its credit facility agreement obtaining an extension to the maturity of its $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2013 and $50 million now maturing in May 2011.

In May 2010 TGVI entered into a two-year $300 million unsecured committed revolving credit facility to replace its $350 million credit facility that was due to mature in January 2011. The terms of the new $300 million credit facility are substantially similar to the terms of the former $350 million credit facility, but there is an increase in pricing reflecting current general market conditions.

In August 2010 Newfoundland Power renegotiated and amended its $100 million unsecured committed credit facility obtaining an extension to the maturity of the facility to August 2013 from August 2011. The amended credit facility agreement reflects an increase in pricing due to current general market conditions but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2010, the Corporation had no off-balance sheet arrangements, with the exception of letters of credit outstanding of $124 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 2010 (2009 – 93%), while approximately 87% of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2010 (2009 – 88%). The Corporation's regulated utilities are subject to the normal uncertainties faced by regulated entities, including approvals 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 depends on 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 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 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.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected or fair rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, 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.

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 PUC's June 2008 Final Decision, regulatory challenges continued at Belize Electricity that impeded the utility's ability to earn a fair and reasonable return in 2010. Belize Electricity contributed $1.5 million to the consolidated earnings of Fortis for 2010 compared to an expected $10 million in the course of normal operations. For a further discussion of regulatory matters at Belize Electricity, refer to the "Regulatory Highlights – Material Regulatory Decisions and Applications – Belize Electricity" section of this MD&A.

All of the Corporation's regulated utilities operate under COS methodologies. FortisBC is also subject to a PBR mechanism extending into 2011, which provides the utility an opportunity to earn in excess of the allowed ROE determined by the BCUC. Upon expiry of the PBR mechanism, there is no certainty as to whether a new PBR mechanism will be entered into or what the particular terms of any renewed PBR mechanism will be. The PBR mechanism at TGI expired at the end of 2009, with a two-year phase-out, and the BCUC-approved rate settlement agreement reached at TGI pertaining to 2010 and 2011 revenue requirements did not provide for the continuation of a new PBR mechanism for 2010 and 2011. Under the 2010 and 2011 rate settlement agreement, certain COS variances are subject to deferral account treatment and the balances are at the respective company's risk.

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.

Operating and Maintenance Risks: The Terasen Gas 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 Terasen Gas companies maintain facility risk assessment, pipeline integrity management and damage prevention programs and pipeline security systems as preventive measures to mitigate the risk of a pipeline failure or other loss of system integrity. 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 difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Terasen Gas companies, FortisBC 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 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. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace 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 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 financial condition and results of operations of the utilities.

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 for 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; performance of employees, contractors, subcontractors or equipment suppliers; price; 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.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the level of new multi-family housing starts is continuing to 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.

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 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. 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 8% per annum over the next five years. Approximately 55% of Fortis Properties' operating income was derived from hotel investments in 2010 (2009 – 55%). Same-hotel revenue increased at Fortis Properties' Hospitality Division in 2010. Revenue growth will be challenged in 2011 due to the impact of the continuing economic downturn in certain operating regions and increased supply in various markets. It is estimated that a 10% decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or any 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 results of operations and the financial position of the Corporation and its 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) will 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 repay existing debt and to fund capital expenditures.

The Corporation and its currently rated-regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Also, a significant downgrade in the credit ratings of TGI or Terasen could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. As discussed in the "Liquidity and Capital Resources – Capital Structure" section of this MD&A, S&P confirmed the Corporation's long-term corporate and unsecured debt credit rating in December 2010 and DBRS upgraded the Corporation's unsecured debt credit rating to A(low) from BBB(high) in October 2010. During 2010 the only changes in credit ratings for the Corporation's currently rated utilities were for FortisBC and Maritime Electric. Moody's upgraded FortisBC's senior unsecured debt credit rating to Baa1 from Baa2 and DBRS upgraded FortisBC's secured and unsecured debenture credit rating to A(low) from BBB(high). S&P, however, lowered Maritime Electric's senior secured debt credit rating to A– from A and revised the recovery rating on the debt to '1' from '1+'. 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 placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

Despite the volatility that 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 capital markets can increase the cost, and affect the timing, of the issuance of long-term capital by the Corporation and its utilities. While the cost of borrowing may increase, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. The cost of recently renewed and extended credit facilities has increased and may also increase going forward; however, the increase in interest expense and/or fees has not significantly impacted the Corporation's consolidated financial results for 2010. During 2010 TGVI and Newfoundland Power renegotiated their respective credit facility agreements in advance of the scheduled maturity dates, resulting in substantially similar terms as the former credit facilities, but with 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 committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes. Most of the committed credit facilities have maturities in 2012 and 2013.

Further information on the Corporation's 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 28 to the 2010 Consolidated Financial Statements.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are 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 TGI a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

At the Terasen Gas 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 Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Earnings of the Terasen Gas 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 climatic conditions that prevail 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 operations, 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'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 the Company's generating plants or at generating plants operated by parties contracted to supply energy to FortisBC.

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 affecting the Corporation's service territories.

The assets and earnings of Belize Electricity, 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. In Belize additional costs in the event of a hurricane would be deferred and Belize Electricity may apply for future recovery in customer rates. 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 mitigates 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 hydrologic risk associated with the project.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies, which include a combination of both physical and financial transactions, to reduce price volatility and ensure, to the extent possible, that natural gas costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are approved by the BCUC and gains or losses effectively accrue entirely to customers. 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.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects 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 gas commodity costs could materially affect the Terasen Gas companies despite regulatory measures available for compensating 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 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 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 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 Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a designated 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.

On an annual basis, TGI and TGVI each file a PRMP that seeks approval for the Companies' natural gas commodity hedging plan for the next three years for TGI and the next five years for TGVI. During the third quarter of 2010, the BCUC denied the most recent PRMP application filed by the Terasen Gas companies earlier in 2010 and directed the Companies to undertake a review of the primary objectives of the PRMP. As a result, the Terasen Gas companies have completed their hedging program for the current winter period related to previously approved PRMPs, but have not entered into any additional derivatives for any subsequent periods. The Terasen Gas companies have subsequently had discussions with the BCUC regarding objectives and hedging strategy and hired a consultant to help with the development of an enhanced hedging strategy. In January 2011 TGI filed its review of the PRMP with the BCUC related to its gas commodity hedging plan and also submitted a 2011-2014 PRMP. TGVI plans to file an updated PRMP by April 2011.

The Corporation's earnings from, and net investment in, its 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 or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00. As at December 31, 2010, the Corporation's corporately held US$590 million (December 31, 2009 – US$390 million) long-term debt had been designated as a hedge of a significant portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on foreign net investments, which are also recognized in other comprehensive income. As at December 31, 2010, 99% of the Corporation's foreign net investments were hedged (December 31, 2009 – 69%).

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 0.99, as at December 31, 2010, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2011.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean 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.

Interest Rate Risk: Generally, allowed rates of return for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed rates of return 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 considering long-term interest rate trends. The formulaic ROE automatic adjustment mechanisms tied to long-term Canada bond yields, used in recent years at the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, have resulted in lower allowed ROEs. In response to the decrease in long-term interest rates, many regulators in Canada reviewed the cost of capital of many utilities. In December 2009 the BCUC issued a decision increasing the allowed ROEs at TGI and FortisBC to 9.50% and 9.90%, respectively. The BCUC also determined that the previous ROE automatic adjustment mechanism will no longer apply and that the allowed ROE as determined in the BCUC decision will apply until reviewed further by the BCUC. In November 2009 the AUC issued its 2009 GCOC Decision. The 2009 GCOC Decision increased the allowed ROE of utilities in Alberta that the AUC regulates, including FortisAlberta, to 9.00% and suspended the use of the ROE automatic adjustment mechanism. FortisAlberta's allowed ROE of 9.00% for 2011 is deemed interim pending the outcome of a proceeding that has been initiated by the AUC to review the determination of the allowed ROE for 2011 and whether a formula-based approach for setting ROEs beginning in 2012 is warranted. In December 2009 the OEB issued a report reviewing cost of capital for utilities in Ontario and made changes to the ROE automatic adjustment mechanism to reduce sensitivity to changes in Canada bond yields and included an additional factor for utility bond spreads. The ROE automatic adjustment mechanism continues at Newfoundland Power for at least 2011 and 2012. The mechanism, however, has resulted in a decrease in the allowed ROE for Newfoundland Power for 2011 to 8.38% down from 9.00% for 2010.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under credit facilities and floating-rate long-term debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates.

As at December 31, 2010, approximately 81% of the Corporation's consolidated long-term debt and capital lease obligations 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, 2010.

Total Debt

As at December 31, 2010	*($ millions)*	*(%)*
Short-term borrowings	**358**	**6.0**
Utilized variable-rate credit facilities classified as long term	**218**	**3.6**
Variable-rate long-term debt and capital lease obligations (including current portion)	**11**	**0.2**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**5,436**	**90.2**
Total	**6,023**	**100.0**

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, 2010, 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 2010 financial results, is disclosed in Note 28 to the 2010 Consolidated Financial Statements.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. The Terasen Gas companies did not experience any counterparty defaults in 2010 and are not expecting 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: There is no assurance that natural gas will continue to maintain a competitive price advantage in the future when compared with alternative energy sources. If natural gas pricing becomes uncompetitive with pricing for electricity and other alternative energy sources, the ability of the Terasen Gas 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 Terasen Gas companies in rates charged to customers. Refer also to the "Business Risk Management – Risks Related to TGVI" and "Environmental Risks" sections of this MD&A.

Natural Gas and Fuel Supply: The Terasen Gas companies are dependent on a limited number 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 Terasen Gas 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 Terasen Gas 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 Terasen Gas companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers.

Caribbean Utilities and Fortis Turks and Caicos are dependent on third parties for the supply of all their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of fuel could have a material impact on the operations of the utilities.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees. Approximately 62% 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. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 3 to the 2010 Consolidated Financial Statements. 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, accrued benefit asset, accrued benefit liability and benefit obligation.

The above 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 Terasen Gas companies and FortisBC, and at Newfoundland Power beginning in 2010, 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. 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 TGVI: TGVI operates in the price-competitive service area of Vancouver Island, with a customer base and revenue that is currently sufficient to meet the Company's current COS. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement provides royalty revenue from the Government of British Columbia that currently covers approximately 20% of the COS. This revenue is due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of accumulated revenue deficiencies, if any. The remaining amount outstanding under non-interest bearing government loans, which is currently treated as a reduction of rate base, is expected to be repaid by the end of 2016. As at December 31, 2010, the balance outstanding under these loans was $49 million. As the debt is repaid, the higher rate base will increase COS and customer rates. With the cessation of royalty revenues 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.

Management Discussion and Analysis

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 relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are located. 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 established a long-term vision for the province as a leader in clean energy development, 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. The Energy Plan directly influenced the development of FortisBC's Resource Plan and Rate Design Applications, both filed with the BCUC in 2009. FortisBC and the Terasen Gas 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. The reporting regulation, already in effect under the *Greenhouse Gas Reduction (Cap and Trade) Act*, will require the Terasen Gas companies to report and have external verification on GHG emissions generated by its facilities. As well, regulations are being developed under the *Greenhouse Gas Reduction (Cap and Trade) Act* that are expected to lead to an emission trading environment, which may increase the cost and competitiveness of natural gas versus alternative energy sources.

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended in 2007 and 2003 to the Cayman Islands and Belize, respectively. 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 governments of these countries and, accordingly, Caribbean Utilities and Belize Electricity are currently unable to assess the financial impact of compliance with the framework of the protocol.

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.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on their facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

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 on insurance, 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 regulatory 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, 2010, there were no material environmental liabilities recognized in the Corporation's 2010 Consolidated Financial Statements and there were no material unrecorded environmental liabilities known to management. 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 is expected to implement an EMS by 2012. 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 2010 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 costs related to carrying out the EMSs, 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, 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. 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 flow 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 flow and financial position.

It is anticipated that such 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 and government agencies. 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'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 as of July 1, 2005 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 utility 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 growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

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 flow and financial position of FortisAlberta.

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

Transition to New Accounting Standards: Fortis has initiated a plan to adopt US GAAP, as opposed to IFRS, effective January 1, 2012. The project plan is described further in the "Future Accounting Changes" section of this MD&A.

Fortis expects to become a U.S. Securities and Exchange Commission ("SEC") Issuer by December 31, 2011 and, thereby, qualify to apply US GAAP for the purpose of meeting financial and regulatory reporting requirements in Canada effective January 1, 2012. Fortis has commenced an intensive analysis of the significant differences in accounting policies between Canadian GAAP and US GAAP and the possible effect these differences may have on its future financial reporting.

Operating earnings from the Corporation's rate-regulated activities comprised approximately 87% of total operating earnings for 2010. Fortis expects earnings recognized under US GAAP to be closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued ability to recognize regulatory assets and liabilities. Further analysis is required to confirm and quantify the possible financial reporting impacts of adopting US GAAP, including any differences in accounting policies that will affect earnings to be recognized by the Corporation's non-regulated operations.

Should the Corporation not be successful in becoming an SEC Issuer by December 31, 2011, Fortis will be required to adopt IFRS effective January 1, 2012. In the absence of an accounting standard for rate-regulated activities being established by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities, and could result in significant volatility in the Corporation's consolidated earnings, as recognized under IFRS, from those otherwise recognized under US GAAP or previous Canadian GAAP.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes require governments of these tax-free jurisdictions to 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 will continue to be able to be repatriated to Canada tax-free.

The Government of Canada announced that it had entered into TIEA negotiations with Belize in June 2010. TIEA negotiations with the Cayman Islands and the Turks and Caicos Islands were successfully completed in June 2010 and are awaiting ratification. 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.

Once the TIEAs are in force with the Cayman Islands and the Turks and Caicos Islands, the earnings of the Corporation's Canadian-owned subsidiaries operating in these jurisdictions will continue to be able to be repatriated to Canada tax-free after 2014. Conversely, if Belize is unable to establish a TIEA with Canada, earnings of Belize Electricity and BECOL will be taxed on an accrual basis after 2014 as if they were earnings in Canada which, for Fortis, will result in reduced earnings' contribution from these subsidiaries.

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

Information Technology Infrastructure: 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 distribution, transmission and generation facilities; provide customers with billing 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.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' reserves and maintain gas and electric 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 Terasen Gas companies and FortisBC 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 Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC.

Furthermore, a recent decision by the Supreme Court of Canada established 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. If the BCUC decides that Crown consultation and accommodation have not been adequate, the BCUC will not issue its approval or will place conditions on its approval.

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 Indian and Northern Affairs 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: Approximately 60% 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 provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by 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 flow and financial position of the utilities.

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

The collective agreement between FortisBC and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired January 31, 2011. The Company and COPE have agreed in principle to explore amalgamating FortisBC and TGI's collective agreements with COPE. The current collective agreement between COPE and FortisBC will remain in full effect until an amalgamation is agreed to or discussions cease. Should the parties be unable to reach an amalgamated agreement, FortisBC plans to commence negotiation for a revised collective agreement.

The two collective agreements between Newfoundland Power and the International Brotherhood of Electrical Workers, Local 1620, will expire in September 2011.

Human Resources: 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 an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

CHANGES IN ACCOUNTING POLICIES AND STANDARDS

Effective January 1, 2010, as approved by the regulator, FortisAlberta began capitalizing 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 2010 amortization costs of approximately $5 million were capitalized.

Effective January 1, 2010, as a result of the BCUC-approved NSAs related to 2010 and 2011 revenue requirements, the Terasen Gas companies adopted the following new accounting policies:

(i) Asset removal costs are now recognized in operating expenses on the consolidated statement of earnings. The annual amount of such costs approved for recovery in customer rates in 2010 was approximately $8 million. Actual costs incurred in excess of, or below, the approved amount are to be recognized in a regulatory deferral account for recovery from, or refund to, customers in future rates, beginning in 2012. Removal costs are direct costs incurred by the Terasen Gas companies in taking assets out of service, whether through actual removal of the assets or through the disconnection of the assets from the transmission or distribution system. During 2010 actual asset removal costs of approximately $10 million were incurred, with $8 million recognized in operating expenses and $2 million deferred as a regulatory asset. Prior to January 1, 2010, asset removal costs were recognized against accumulated amortization on the consolidated balance sheet.

(ii) Gains and losses on the retirement or disposal of utility capital assets are now recognized in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval. During 2010 losses of approximately $16 million were deferred and recognized as a regulatory asset on the consolidated balance sheet. Prior to January 1, 2010, gains and losses on the retirement or disposal of utility capital assets were recognized against accumulated amortization on the consolidated balance sheet.

(iii) Amortization of utility capital assets and intangible assets now commences the month after the assets are available for use. Prior to January 1, 2010, amortization commenced the year following when the assets became available for use. During 2010 additional amortization costs of approximately $2 million were incurred, due to the change in commencement of amortization of utility capital assets and intangible assets.

Business Combinations

Effective January 1, 2010, the Corporation early adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests*. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of an acquiree in a business combination results in a different calculation of goodwill with respect to acquisitions on or after January 1, 2010. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have a material impact in the Corporation's consolidated financial statements for the year ended December 31, 2010.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for non-controlling interests in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 resulted in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent company and to non-controlling interests are now separately disclosed on the consolidated statements of earnings and comprehensive income.

FUTURE ACCOUNTING CHANGES

Adoption of New Accounting Standards: In February 2008 the Canadian Accounting Standards Board ("AcSB") confirmed that Canadian GAAP for publicly accountable enterprises would be replaced by IFRS for fiscal years beginning on or after January 1, 2011.

The Corporation commenced its IFRS Conversion Project in 2007 when it established a formal project governance structure, which included the Fortis Audit Committee, senior management and project teams from each of the Fortis subsidiaries. Overall project governance, management and support have been coordinated by Fortis, with an independent external advisor engaged to assist in the IFRS conversion.

IFRS does not currently provide guidance with respect to accounting for rate-regulated activities. Over the past two to three years, the IASB discussed and deliberated on the subject of accounting for rate-regulated activities, but failed to reach a conclusion on any of the associated technical issues. In September 2010 the IASB reconfirmed its earlier view that matters associated with rate-regulated accounting could not be resolved quickly. The IASB, therefore, decided to defer any further discussion on accounting for rate-regulated activities until public consultation on its future agenda is held, and views as to what form, if any, a future project might take to address accounting for the effects of rate-regulated activities are obtained. Without specific guidance on accounting for rate-regulated activities by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities, and net earnings may, as a result, be subject to significant volatility under current application of IFRS.

The pace and outcome of the IASB's activities have put Canadian rate-regulated entities at a significant disadvantage in terms of their ability to adopt IFRS as of January 1, 2011. Accordingly, the AcSB has provided qualifying entities with an option to defer their changeover to IFRS by one year. The necessary amendments to the CICA Handbook were published by the AcSB in October 2010.

While the Corporation's IFRS Conversion Project has proceeded as planned in preparation for the adoption of IFRS on January 1, 2011, Fortis and its rate-regulated subsidiaries qualify for the optional one-year deferral and, therefore, will continue to prepare their financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis has evaluated the option of adopting US GAAP effective January 1, 2012. Canadian rules allow a reporting issuer to prepare and file its financial statements 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 has developed and initiated a plan to become an SEC Issuer by December 31, 2011. As an SEC Issuer, Fortis will then be permitted to prepare and file its consolidated financial statements in accordance with US GAAP. Barring a change that will provide certainty as to the Corporation's ability to recognize regulatory assets and liabilities under IFRS, Fortis expects to prepare its consolidated financial statements in accordance with US GAAP for all interim and annual periods beginning on or after January 1, 2012. Several other Canadian investor-owned rate-regulated utilities are also expected to take a similar approach to possible adoption of US GAAP in 2012.

The adoption of US GAAP in 2012 is expected to result in fewer significant changes to the Corporation's accounting policies as compared to those that may have resulted with the adoption of IFRS. The Corporation's application of Canadian GAAP currently relies on US GAAP for guidance on accounting for rate-regulated activities, which 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, more accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

The Corporation's plan to adopt US GAAP effective January 1, 2012 consists of the following three phases:

Phase I – Scoping and Diagnostics: This phase consists of project initiation and awareness; identification of high-level differences between US GAAP and Canadian GAAP; and project planning and resourcing. Work on Phase I commenced in the fourth quarter of 2010 and is scheduled for completion by mid-2011.

Phase II – Analysis and Development: This phase consists of detailed diagnostics and evaluation of the financial impacts of adopting US GAAP; identification and design of operational and financial business processes; and development of required solutions to address identified issues. Phase II of the plan commenced in January 2011 and is scheduled for completion by the third quarter of 2011.

Phase III – Implementation and Review: This phase involves implementation of the changes required by the Corporation to prepare and file its consolidated financial statements based on US GAAP beginning in 2012 and communication of the associated impacts. Phase III will commence in the second quarter of 2011 and will conclude when the Corporation issues its first annual audited US GAAP consolidated financial statements for the year ending December 31, 2012. Commencing with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP.

The Corporation's IFRS project advisors will also advise the Corporation on accounting related matters with respect to the adoption of US GAAP. Legal counsel has also been engaged to assist with securities' filings and other legal matters associated with the adoption of US GAAP.

FINANCIAL INSTRUMENTS

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, 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 market 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.

The carrying and fair values of the Corporation's consolidated long-term debt and preference shares as at December 31 were as follows.

Financial Instruments

As at December 31	**2010**		2009	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion [(1)]	**5,669**	**6,431**	5,502	5,906
Preference shares, classified as debt [(2)]	**320**	**344**	320	348

[(1)] Carrying value as at December 31, 2010 excludes unamortized deferred financing costs of $42 million (December 31, 2009 – $39 million) and capital lease obligations of $38 million (December 31, 2009 – $37 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 $615 million as at December 31, 2010 (December 31, 2009 – carrying value $347 million; fair value $356 million).

From time to time the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates 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.

Derivative Financial Instruments

As at December 31	**2010**				2009	
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 contracts	**< 1.5**	**2**	**–**	**–**	–	–
Natural gas derivatives:						
Swaps and options	**Up to 4**	**163**	**(162)**	**(162)**	(119)	(119)
Gas purchase contract premiums	**Up to 3**	**74**	**(5)**	**(5)**	(3)	(3)

The foreign exchange forward contracts are held by the Terasen Gas companies. During 2010 TGI entered into a foreign exchange forward contract to hedge the cash flow risk related to approximately US$8 million remaining to be paid under a contract for the implementation of a customer information system. TGVI also has a foreign exchange forward contract to hedge the cash flow risk related to approximately US$1 million remaining to be paid under a contract for the construction of an LNG storage facility.

The natural gas derivatives are held by the Terasen Gas 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 Terasen Gas 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. For further information refer to the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A.

The changes in the fair values of the foreign exchange forward 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 foreign exchange forward contracts were recognized in accounts payable as at December 31, 2010 and accounts receivable as at December 31, 2009. The fair values of the natural gas derivatives were recognized in accounts payable as at December 31, 2010 and 2009.

The foreign exchange forward contracts are valued using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. 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 contracts and the natural gas derivatives are estimates of the amounts the Terasen Gas companies would have to receive or pay to terminate the outstanding contracts as at the balance sheet dates.

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

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with 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.

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 using Canadian GAAP 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, 2010, Fortis recognized $1,072 million in current and long-term regulatory assets (December 31, 2009 – $947 million) and $527 million in current and long-term regulatory liabilities (December 31, 2009 – $474 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, 2010, the Corporation's consolidated utility capital assets, income producing properties and intangible assets were approximately $9.1 billion, or approximately 70% of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangible assets of approximately $8.5 billion, or approximately 70% of total consolidated assets, as at December 31, 2009. The increase in capital assets was primarily associated with capital expenditures, which totalled more than $1 billion in 2010. Amortization costs for 2010 were $410 million compared to $364 million for 2009. 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 the respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual asset removal and site restoration costs, net of salvage proceeds, are recognized against the provision when incurred. The accrual of the estimated costs is included with amortization costs and the provision balance is recognized as a long-term regulatory liability. 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, 2010 was $339 million (December 31, 2009 – $326 million). The amount of asset removal and site restoration costs provided for and recognized in amortization costs during 2010 was $50 million (2009 – $29 million).

Management Discussion and Analysis

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. Changes in regulator-approved amortization rates at the Terasen Gas companies and FortisAlberta during 2010 materially impacted consolidated amortization costs. The composite amortization rate at the Terasen Gas companies and FortisAlberta increased to 2.79% for 2010 from 2.63% for 2009 and increased to 4.27% for 2010 from 3.94% for 2009, respectively. The increase in amortization costs at the Terasen Gas companies and FortisAlberta is approved for collection in customer rates. As part of its 2010 GRA, Newfoundland Power was ordered by its regulator to complete an amortization study to be based on utility capital assets and intangible assets in service as at December 31, 2009. This study is ongoing and is expected to be completed in the first half of 2011.

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 write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs, or if circumstances change, that would indicate that the fair value of a reporting unit was below its carrying value. As at October 1 of each year, the Corporation reviews for impairment of goodwill. 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. Fair market value is determined using net present value financial models and management's assumption of the future profitability of the reporting units. 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, 2010.

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 assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2011, is 7% for the larger defined benefit pension plans, which is unchanged from the assumed long-term rate of return used in 2010. The defined benefit pension plan assets experienced total positive returns of approximately $67 million compared to expected positive returns of $46 million in 2010. 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 discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2010 and to determine net pension cost for 2011 range from 5.00% to 5.75% for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2009 and determine net pension cost for 2010, which ranged from 5.75% to 6.50%. The discount rates decreased, driven mainly by 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 an $11 million increase in consolidated defined benefit net pension cost for 2010 compared to 2009 as a result of the impact of lower assumed discount rates for calculating net pension cost in 2010 compared to 2009 and the amortization of net actuarial losses that arose in prior years.

Consolidated defined benefit net pension cost for 2011 is expected to be higher than for 2010, driven mainly by decreases in discount rates assumed in the measurement of the pension obligations, for the reason described above, and the amortization of net actuarial losses that arose in prior years.

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 2010 defined benefit net pension cost, and the related accrued defined benefit pension asset and liability recognized in the Corporation's 2010 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, 2010

Increase (decrease)	**Net pension benefit cost**		**Accrued benefit asset**		**Accrued benefit liability**		**Accrued benefit obligation**	
($ millions)	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**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	–	(4)	(1)	4	–	–	31	1
Impact of decreasing the rate of return assumption by 100 basis points	–	4	–	(4)	–	–	(26)	(4)
Impact of increasing the discount rate assumption by 100 basis points	(3)	(5)	2	5	(1)	–	(50)	(60)
Impact of decreasing the discount rate assumption by 100 basis points	5	5	(4)	(5)	1	–	61	76

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. The assumptions 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, FortisAlberta and Newfoundland Power recognize the cost of defined benefit pension and/or OPEB plan benefits on a cash basis, whereby differences between the cash payments made during the year and the cost incurred during the year are deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions cause changes in regulatory assets and liabilities for these companies and do not affect earnings. 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 OPEB plans as discussed in the "Material Regulatory Decisions and Applications – Newfoundland Power" section of this MD&A. As discussed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the Terasen Gas companies and FortisBC, and Newfoundland Power beginning in 2010, 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.

As at December 31, 2010, the Corporation had a consolidated accrued benefit asset of $146 million (December 31, 2009 – $146 million) and a consolidated accrued benefit liability of $201 million (December 31, 2009 – $186 million). During 2010 the Corporation recognized a consolidated net benefit cost of $36 million (2009 – $26 million) for all defined benefit and OPEB plans.

Asset-Retirement Obligations: The measurement of the fair value of an ARO requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. 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, 2010 and 2009, with the exception of AROs recognized by FortisBC.

During the second quarter of 2010, FortisBC obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from its electrical equipment. All factors used in estimating the Company's AROs 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. As at December 31, 2010, FortisBC has recognized approximately $3 million in AROs, which have been classified on the consolidated balance sheet as long-term other liabilities with the offset to utility capital assets.

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, 2010, 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: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Recognizing revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. 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, 2010, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $313 million (December 31, 2009 – $294 million) on annual consolidated revenue of approximately $3,664 million for 2010 (2009 – $3,643 million).

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Fortis Turks and Caicos and Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated to constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulator. In 2010 GEC totalled $57 million (2009 – $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. Effective January 1, 2010, as provided in the BCUC-approved NSAs for 2010 and 2011, the percentage for calculating and capitalizing general overhead costs to utility capital assets at the Terasen Gas companies decreased from 16% to 14%. As a result of this change, operating expenses increased approximately $5 million in 2010 compared to 2009, with a corresponding decrease in utility capital assets. The resulting increase in operating expenses has been approved for recovery in customer delivery rates.

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.

Terasen

During 2007 and 2008, a non-regulated subsidiary of Terasen 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. Terasen has begun the appeal process associated with the assessments.

In 2009 Terasen 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. Terasen has filed a statement of defence but the claim is in its early stages. During the second quarter of 2010, Terasen 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

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. FortisBC is communicating with its insurers and has filed a statement of defence in relation to both actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Exploits Partnership

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating plants 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.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2010, 2009 and 2008. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2010**	2009	2008
Revenue	**3,664**	3,643	3,907
Net earnings	**323**	292	272
Net earnings attributable to common equity shareholders	**285**	262	245
Total assets	**12,903**	12,139	11,166
Long-term debt and capital lease obligations (excluding current portion)	**5,609**	5,276	4,884
Preference shares (1)	**912**	667	667
Common shareholders' equity	**3,305**	3,193	3,046
Basic earnings per common share	**1.65**	1.54	1.56
Diluted earnings per common share	**1.62**	1.51	1.52
Dividends declared per common share (2)	**1.41**	0.78	1.01
Dividends declared per First Preference Share, Series C (2)	**1.7031**	1.0219	1.3625
Dividends declared per First Preference Share, Series E (2)	**1.5313**	0.9188	1.2250
Dividends declared per First Preference Share, Series F (2)	**1.5313**	0.9188	1.2250
Dividends declared per First Preference Share, Series G (2) (3)	**1.6406**	0.9844	1.0184
Dividends declared per First Preference Share, Series H (2) (4)	**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 9.2 million Five-Year Fixed Rate Reset First Preference Shares, Series G were issued on May 23, 2008 and June 4, 2008 at $25.00 per share for net after-tax proceeds of $225 million, which are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum for the first five years.

(4) 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.

2010/2009: Revenue increased $21 million, or 0.6%, 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 increase was 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 due to warmer average temperatures. 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 Terasen Gas companies from July 1, 2009 and for FortisBC from January 1, 2010, as well as an increase in the equity component at TGI 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 systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the impact of foreign exchange. 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 shares for 2010 increased over 2009 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.

2009/2008: Revenue decreased $264 million, or 6.8%, over 2008. The decrease was driven by the flow through to customers of lower natural gas commodity and energy supply costs, combined with the loss of revenue subsequent to the expiration of the Rankine water rights in Ontario in April 2009. The decrease was partially offset by the impact of base customer rate increases and customer growth, mainly in Canada, in addition to the favourable impact of foreign currency translation. Net earnings attributable to common equity shareholders increased $17 million, or 6.9%, over 2008. Earnings in 2008 were enhanced by a one-time $7.5 million tax reduction at Terasen and were reduced by one-time charges of approximately $15 million pertaining to Belize Electricity and FortisOntario. Earnings in 2009 were favourably impacted by a one-time $3 million adjustment to future income taxes related to prior periods at FortisOntario and were reduced by a one-time $5 million after-tax provision for the project cost overrun related to the conversion of Whistler customer appliances from propane to natural gas. Excluding the above items, earnings were higher year over year mainly due to the impact of an increase in the allowed ROEs for 2009 at FortisAlberta and TGI and an increase in the equity component at FortisAlberta, combined with rate base growth, mainly at the electric utilities in western Canada. Growth in earnings was partially offset by lower contribution from non-regulated generation operations in Ontario, due to the expiration of the Rankine water rights on April 30, 2009, and ongoing regulatory challenges at Belize Electricity. The growth in total assets was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, and an increase in regulatory assets driven by the adoption of the amended accounting standard pertaining to income taxes. The increase was partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the impact of foreign exchange. Basic earnings per common share decreased 2 cents, or 1.3%, from 2008 due to dilution associated with the issuance of $300 million common shares in December 2008. Dividends declared per common and preference shares for 2009 were lower than for 2008 due to the timing of the declaration of dividends for the same reason as discussed above.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the quarters ended December 31, 2010 and 2009. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. A discussion of the financial results for the fourth quarter of 2010 is also contained in the Corporation's fourth quarter 2010 media release, dated and filed on SEDAR at www.sedar.com on February 10, 2011, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31 *(Unaudited)*	**Gas Volumes** *(TJ)* **Energy and Electricity Sales** *(GWh)*			**Revenue** *($ millions)*		
	2010	2009	Variance	**2010**	2009	Variance
Regulated Gas Utilities – Canadian						
Terasen Gas Companies	**60,398**	65,000	(4,602)	**480**	497	(17)
Regulated Electric Utilities – Canadian						
FortisAlberta	**4,255**	4,129	126	**99**	86	13
FortisBC	**847**	859	(12)	**73**	69	4
Newfoundland Power	**1,488**	1,474	14	**152**	146	6
Other Canadian Electric Utilities	**578**	582	(4)	**87**	79	8
	7,168	7,044	124	**411**	380	31
Regulated Electric Utilities – Caribbean	**270**	291	(21)	**84**	85	(1)
Non-Regulated – Fortis Generation	**137**	87	50	**9**	5	4
Non-Regulated – Fortis Properties				**57**	54	3
Corporate and Other				**7**	6	1
Inter-Segment Eliminations				**(12)**	(7)	(5)
Total				**1,036**	1,020	16

Factors Contributing to Gas Volumes Variance

Unfavourable

- Lower average gas consumption by residential and commercial customers, as a result of warmer temperatures

Favourable

- Higher transportation volumes, as a result of the favourable impact of continued improving economic conditions in the forestry sector, including a pulp and paper mill customer returning to service

Factors Contributing to Energy and Electricity Sales Variance

Favourable

- Increased energy deliveries at FortisAlberta, associated with an increase in the number of customers and higher average consumption by commercial and oil and gas customers, due to increased oil and gas activities, partially offset by lower average consumption by farm and irrigation, and residential customers, mainly due to relatively milder temperatures and increased rainfall
- Increased electricity sales at Newfoundland Power associated with customer growth, partially offset by lower average consumption mainly due to milder temperatures and lower activity in the commercial sector
- Increased energy sales at Non-Regulated – Fortis Generation, due to higher rainfall and the commissioning of the Vaca hydroelectric generating facility in Belize in March 2010, combined with higher production in Upper New York State, Ontario and British Columbia, due to higher rainfall

Unfavourable

- Lower electricity sales at FortisBC associated with lower average consumption, primarily due to unfavourable weather conditions, partially offset by customer growth
- Lower electricity sales at Other Canadian Electric Utilities, due to lower average consumption in Ontario, mainly due to reduced space heating load as a result of warmer temperatures, partially offset by higher consumption on PEI due to residential customer growth, warmer temperatures favourably impacting crop storage cooling for the farming sector and increased processing activity in the commercial sector
- Lower electricity sales at Caribbean Regulated Electric Utilities, due to decreased air conditioning load, as a result of lower average temperatures experienced on Grand Cayman and in the Turks and Caicos Islands and Belize

Factors Contributing to Revenue Variance

Favourable

- Base customer rate increases at the regulated utilities in Canada, including the accrual of electricity rate revenue at FortisAlberta related to its regulator-approved revenue requirements for 2010
- Customer growth at FortisAlberta
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities and Other Canadian Regulated Electric Utilities
- Increased energy sales, and higher average energy sales rates per MWh in Upper New York State and Ontario at Non-Regulated – Fortis Generation
- Higher electricity sales at Newfoundland Power
- Higher revenue contribution from hotel properties in Atlantic Canada and central Canada and growth in all regions of the Real Estate Division

Unfavourable

- The flow through to customers of lower commodity cost of natural gas and lower consumption of natural gas at the Terasen Gas companies
- The unfavourable impact of foreign currency translation of $4 million
- Electricity rate revenue in the fourth quarter of 2009 reflected the favourable $3 million retroactive impact, relating to the first three quarters of 2009, of the increase in the allowed ROE and equity component, effective January 1, 2009, at FortisAlberta
- The decrease in electricity sales at FortisBC, Caribbean Regulated Electric Utilities and Other Canadian Regulated Electric Utilities

Summary of Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions, except for per share amounts)	**2010**	2009	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**45**	48	(3)
Regulated Electric Utilities – Canadian			
FortisAlberta	**17**	15	2
FortisBC	**10**	8	2
Newfoundland Power	**9**	8	1
Other Canadian Electric Utilities	**5**	7	(2)
	41	38	3
Regulated Electric Utilities – Caribbean	**5**	7	(2)
Non-Regulated – Fortis Generation	**5**	2	3
Non-Regulated – Fortis Properties	**7**	5	2
Corporate and Other	**(18)**	(19)	1
Net Earnings Attributable to Common Equity Shareholders	**85**	81	4
Basic Earnings per Common Share	**0.49**	0.48	0.01

Earnings: Earnings for the fourth quarter were $85 million, or $0.49 per common share, up from $81 million, or $0.48 per common share, for the same quarter in 2009. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, non-regulated hydroelectric operations in Belize and lower effective corporate income taxes at Fortis Properties, partially offset by lower earnings from the Terasen Gas companies and Caribbean Regulated Electric Utilities. Improved performance at Canadian Regulated Electric Utilities was driven by overall growth in electrical infrastructure investment, combined with customer growth at FortisAlberta and the higher allowed ROE at FortisBC. Earnings were lower quarter over quarter at the Terasen Gas companies, as a result of higher regulator-approved operating expenses and the timing of the spending of these increased expenses, and at Caribbean Regulated Electric Utilities, mainly due to lower electricity sales associated with cooler-than-normal temperatures experienced in the region and the inability of Belize Electricity to earn a fair and reasonable return due to regulatory challenges. Earnings for the fourth quarter of 2009 were reduced by $5 million related to the expensing of the Whistler Conversion Project cost overrun but were favourably impacted by a one-time $3 million tax adjustment at FortisOntario.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)* *($ millions)*	2010	2009	Variance
Cash, Beginning of Period	**64**	106	(42)
Cash Provided by (Used in):			
Operating Activities	**199**	115	84
Investing Activities	**(333)**	(312)	(21)
Financing Activities	**179**	177	2
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**–**	(1)	1
Cash, End of Period	**109**	85	24

Cash flow provided by operating activities, after working capital adjustments, increased $84 million quarter over quarter. The increase was mainly due to: (i) higher earnings; (ii) the collection from customers of increased amortization costs, mainly at the Terasen Gas companies, as approved by the regulators; (iii) favourable working capital changes at the Terasen Gas companies, reflecting differences in the commodity cost of natural gas and the cost of natural gas charged to customers quarter over quarter; and (iv) favourable changes in the AESO charges deferral account at FortisAlberta.

Cash used in investing activities was $21 million higher quarter over quarter, driven by higher gross capital expenditures due to the commencement of construction of the non-regulated Waneta Expansion late in 2010 and increased capital spending at FortisAlberta, partially offset by the acquisition of Algoma Power during the fourth quarter of 2009, higher proceeds from the sale of utility capital assets and higher contributions in aid of construction.

Cash provided by financing activities was $2 million higher quarter over quarter. Higher advances from non-controlling interests and higher proceeds from the issuance of common shares were largely offset by a lower net increase in debt.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2009 through December 31, 2010. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share Basic *($)*	Diluted *($)*
December 31, 2010	1,036	85	0.49	0.47
September 30, 2010	720	45	0.26	0.26
June 30, 2010	836	55	0.32	0.32
March 31, 2010	1,072	100	0.58	0.56
December 31, 2009	1,020	81	0.48	0.46
September 30, 2009	665	36	0.21	0.21
June 30, 2009	756	53	0.31	0.31
March 31, 2009	1,202	92	0.54	0.52

A summary of the past eight quarters reflects the Corporation's continued organic growth and growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis companies, seasonality may vary. Most of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results from May 1, 2009 reflect, as expected, the loss of revenue and earnings subsequent to the expiration, in April 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. Financial results for the fourth quarter ended December 31, 2009 reflected the favourable cumulative retroactive impact, from January 1, 2009, associated with an increase in the allowed ROE and equity component for FortisAlberta.

The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since then. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with a 2010-2011 regulatory rate decision for FortisAlberta. To a lesser degree, financial results from April 2009 were impacted by the acquisition of the Holiday Inn Select Windsor and from October 2009 by the acquisition of Algoma Power.

December 2010/December 2009: Net earnings applicable to common shares were $85 million, or $0.49 per common share, for the fourth quarter of 2010 compared to earnings of $81 million, or $0.48 per common share, for the fourth quarter of 2009. A discussion of the variances between the financial results for the fourth quarter of 2010 and the fourth quarter of 2009 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2010/September 2009: Net earnings attributable to common equity shareholders were $45 million, or $0.26 per common share, for the third quarter of 2010 compared to earnings of $36 million, or $0.21 per common share, for the third quarter of 2009. The increase in earnings was mainly due to improved performance at the regulated electric utilities in western Canada and non-regulated hydroelectric generation operations, partially offset by a higher loss incurred at the Terasen Gas companies and higher corporate expenses. Improved performance at the regulated electric utilities in western Canada was due to higher allowed ROEs and/or equity component and growth in electrical infrastructure investment combined with an increase in the number of customers at FortisAlberta, partially offset by a weather-related decrease in electricity sales at FortisBC and lower net transmission revenue at FortisAlberta. The increase in earnings' contribution from non-regulated hydroelectric generation operations was the result of increased production in Belize, driven by higher rainfall and the commissioning of the Vaca hydroelectric generating facility in March 2010, and lower finance charges. The higher loss quarter over quarter at the Terasen Gas companies largely related to increased operating and maintenance expenses at TGI that were approved by the BCUC as part of the recent NSA. The loss in the third quarter of 2010 at the Terasen Gas companies, however, was reduced by $4 million (after tax) related to the BCUC-approved reversal of most of the project cost overrun previously expensed in the fourth quarter of 2009 associated with the conversion of Whistler customer appliances from propane to natural gas. The increase in corporate expenses was associated with higher preference share dividends, partially offset by lower finance charges.

June 2010/June 2009: Net earnings attributable to common equity shareholders were $55 million, or $0.32 per common share, for the second quarter of 2010 compared to earnings of $53 million, or $0.31 per common share, for the second quarter of 2009. The increase in earnings was driven by the Terasen Gas companies and FortisBC, partially offset by higher corporate expenses. The increase in earnings at the Terasen Gas companies related to higher allowed ROEs and equity component. The improvement in earnings at FortisBC was the result of a higher allowed ROE and growth in electrical infrastructure investment, partially offset by lower electricity sales due to cooler weather experienced in June 2010. The increase in corporate expenses was mainly due to business development costs incurred in 2010 and preference share dividends, partially offset by higher interest income related to increased inter-company lending. Earnings at FortisAlberta were comparable quarter over quarter. The impact of a higher allowed ROE and equity component, compared to those reflected in FortisAlberta's earnings for the second quarter of 2009, combined with growth in electrical infrastructure investment and an increase in customers, was mainly offset by lower corporate income tax recoveries and lower net transmission revenue.

March 2010/March 2009: Net earnings attributable to common equity shareholders were $100 million, or $0.58 per common share, for the first quarter of 2010 compared to earnings of $92 million, or $0.54 per common share, for the first quarter of 2009. The increase in earnings was led by the Terasen Gas companies associated with an increase in the allowed ROEs and equity component. Results also reflected: (i) improved performance at FortisAlberta associated with an increase in the allowed ROE and equity component combined with growth in electrical infrastructure investment and an increase in customers; and (ii) increased earnings at Newfoundland Power, mainly due to growth in electrical infrastructure investment, increased electricity sales and timing differences favourably impacting operating expenses during the quarter. Earnings' growth was tempered by: (i) lower earnings' contribution from non-regulated hydroelectric generation operations due to loss of earnings subsequent to the expiration of the Rankine water rights in April 2009; (ii) lower contribution from Caribbean Regulated Electric Utilities associated with the unfavourable impact of foreign exchange translation, and earnings in the first quarter of 2009 including an approximate $1 million one-time gain; and (iii) higher preference share dividends.

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, 2010 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, 2010 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2010, 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 March 1, 2011 the Terasen Gas companies were renamed to commence operating under a common brand identity with FortisBC in British Columbia, Canada. As a result, the following name changes were made:

Names – Prior to March 1, 2011	Names – Effective March 1, 2011
Terasen Inc.	FortisBC Holdings Inc.
Terasen Gas Inc.	FortisBC Energy Inc.
Terasen Gas (Vancouver Island) Inc.	FortisBC Energy (Vancouver Island) Inc.
Terasen Gas (Whistler) Inc.	FortisBC Energy (Whistler) Inc.
Terasen Energy Services Inc.	FortisBC Alternative Energy Services Inc.

OUTLOOK

The Corporation's significant capital program, which is expected to approach $5.5 billion over the next five years, should drive 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 1, 2011, the Corporation had issued and outstanding 175.3 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, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E as at March 1, 2011 is as follows:

Conversion of Securities into Common Shares

As at March 1, 2011 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	4.3
Convertible Debt	1.4
First Preference Shares, Series C	4.0
First Preference Shares, Series E	6.3
Total	16.0

Additional information, including the Fortis 2010 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

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Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2010 Annual Report have been prepared by management, who is 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 2010 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 2010 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2010 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 2010 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, 2010 and 2009 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, 2010 and 2009 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 2, 2011

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	2010	2009
Current assets		*(Notes 3 & 32)*
Cash and cash equivalents	$ 109	$ 85
Accounts receivable *(Note 28)*	655	595
Prepaid expenses	17	16
Regulatory assets *(Note 5)*	241	221
Inventories *(Note 6)*	168	178
Future income taxes *(Note 21)*	14	29
	1,204	1,124
Assets held for sale *(Note 7)*	45	–
Other assets *(Note 8)*	168	174
Regulatory assets *(Note 5)*	831	726
Future income taxes *(Note 21)*	16	17
Utility capital assets *(Note 9)*	8,202	7,693
Income producing properties *(Note 10)*	560	559
Intangible assets *(Note 11)*	324	286
Goodwill *(Note 12)*	1,553	1,560
	$ 12,903	$ 12,139
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 28)*	$ 358	$ 415
Accounts payable and accrued charges	953	852
Dividends payable	54	3
Income taxes payable	30	23
Regulatory liabilities *(Note 5)*	60	51
Current installments of long-term debt and capital lease obligations *(Note 13)*	56	224
Future income taxes *(Note 21)*	6	24
	1,517	1,592
Other liabilities *(Note 14)*	308	295
Regulatory liabilities *(Note 5)*	467	423
Future income taxes *(Note 21)*	623	570
Long-term debt and capital lease obligations *(Note 13)*	5,609	5,276
Preference shares *(Note 15)*	320	320
	8,844	8,476
Shareholders' equity		
Common shares *(Note 16)*	2,578	2,497
Preference shares *(Note 15)*	592	347
Contributed surplus	12	11
Equity portion of convertible debentures *(Note 13)*	5	5
Accumulated other comprehensive loss *(Note 18)*	(94)	(83)
Retained earnings	804	763
	3,897	3,540
Non-controlling interests *(Note 19)*	162	123
	4,059	3,663
	$ 12,903	$ 12,139

Commitments *(Note 29)*
Contingent liabilities *(Note 30)*

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)	2010	2009
		(Note 3)
Revenue	**$ 3,664**	$ 3,643
Expenses		
Energy supply costs	**1,686**	1,799
Operating	**828**	779
Amortization	**410**	364
	2,924	2,942
Operating income	**740**	701
Finance charges *(Note 20)*	**350**	360
Earnings before corporate taxes	**390**	341
Corporate taxes *(Note 21)*	**67**	49
Net earnings	**$ 323**	$ 292
Net earnings attributable to:		
Non-controlling interests	**$ 10**	$ 12
Preference equity shareholders	**28**	18
Common equity shareholders	**285**	262
	$ 323	$ 292
Earnings per common share *(Note 16)*		
Basic	**$ 1.65**	$ 1.54
Diluted	**$ 1.62**	$ 1.51

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)	2010	2009
		(Note 3)
Balance at beginning of year	**$ 763**	$ 634
Net earnings attributable to common and preference equity shareholders	**313**	280
	1,076	914
Dividends on common shares	**(244)**	(133)
Dividends on preference shares classified as equity	**(28)**	(18)
Balance at end of year	**$ 804**	$ 763

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)	2010	2009
		(Note 3)
Net earnings	**$ 323**	$ 292
Other comprehensive (loss) income		
Unrealized foreign currency translation losses on net investments in self-sustaining foreign operations	**(33)**	(90)
Gains on hedges of net investments in self-sustaining foreign operations	**25**	67
Corporate taxes	**(4)**	(9)
Unrealized foreign currency translation losses, net of hedging activities and tax *(Note 18)*	**(12)**	(32)
Gain on derivative instruments designated as cash flow hedges, net of tax *(Note 18)*	**–**	1
Reclassification to earnings of net losses on derivative instruments previously discontinued as cash flow hedges, net of tax *(Note 18)*	**1**	–
Comprehensive income	**$ 312**	$ 261
Comprehensive income attributable to:		
Non-controlling interests	**$ 10**	$ 12
Preference equity shareholders	**28**	18
Common equity shareholders	**274**	231
	$ 312	$ 261

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)	**2010**	2009
Operating activities		*(Notes 3 & 32)*
Net earnings	**$ 323**	$ 292
Items not affecting cash:		
Amortization – utility capital assets and income producing properties	**368**	317
Amortization – intangible assets	**40**	43
Amortization – other	**2**	4
Future income taxes *(Note 21)*	**(3)**	5
Other	**(5)**	(8)
Change in long-term regulatory assets and liabilities	**9**	25
	734	678
Change in non-cash operating working capital	**(2)**	3
	732	681
Investing activities		
Change in other assets and other liabilities	**–**	(1)
Capital expenditures – utility capital assets	**(1,008)**	(966)
Capital expenditures – income producing properties	**(19)**	(26)
Capital expenditures – intangible assets	**(46)**	(32)
Contributions in aid of construction	**67**	56
Proceeds on sale of utility capital assets	**15**	1
Business acquisitions, net of cash acquired *(Note 23)*	**–**	(77)
	(991)	(1,045)
Financing activities		
Change in short-term borrowings	**(56)**	8
Proceeds from long-term debt, net of issue costs	**523**	729
Repayments of long-term debt and capital lease obligations	**(329)**	(172)
Net borrowings (repayments) under committed credit facilities	**8**	(14)
Advances from (to) non-controlling interests	**45**	(5)
Issue of common shares, net of costs	**80**	46
Issue of preference shares, net of costs	**242**	–
Dividends		
Common shares	**(193)**	(177)
Preference shares	**(28)**	(18)
Subsidiary dividends paid to non-controlling interests	**(9)**	(10)
	283	387
Effect of exchange rate changes on cash and cash equivalents	**–**	(4)
Change in cash and cash equivalents	**24**	19
Cash and cash equivalents, beginning of year	**85**	66
Cash and cash equivalents, end of year	**$ 109**	$ 85

Supplementary Information to Consolidated Statements of Cash Flows *(Note 25)*

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

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

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI").

TGI is the largest distributor of natural gas in British Columbia operating in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

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

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

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

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:* 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 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, as of October 2009, Algoma Power Inc. ("Algoma Power") (Note 23). 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.

Notes to Consolidated Financial Statements

1. Description of the Business (cont'd)

Regulated Utilities (cont'd)

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70% controlling ownership interest in Belize Electricity.

b. *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 generating capacity of 151 MW. Fortis holds an approximate 59% controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

c. *Fortis Turks and Caicos:* Includes P.P.C. Limited ("PPC") 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 57 MW.

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 indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario:* Includes six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls expired on April 30, 2009, at the end of a 100-year term.

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 plants 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 under a 30-year power purchase agreement ("PPA") expiring in 2033. Effective February 12, 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership (Note 30).

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia and the 335-MW Waneta hydroelectric generating facility ("Waneta Expansion"), which is being constructed. The Walden hydroelectric power plant 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 direct 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 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 stations, 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 indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 21 hotels, comprised of more than 4,100 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 Terasen Inc. ("Terasen") and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen 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 Terasen holds a 30% interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. The financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

2. Nature of Regulation

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

Terasen Gas Companies and FortisBC
The Terasen Gas companies and FortisBC 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. TGI, TGVI, TGWI and FortisBC 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 TGI expired on December 31, 2009 with a two-year phase-out as a BCUC-approved Negotiated Settlement Agreement did not include a new PBR mechanism, effective January 1, 2010.

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").

TGI, TGVI, TGWI and FortisBC 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 for deferral account treatment and/or through the operation of PBR mechanisms.

Under the previous PBR mechanism, TGI customers equally shared in achieved earnings above or below the allowed ROE. During 2008 the BCUC extended the PBR mechanism for FortisBC for the years 2009 through 2011. Under the PBR mechanism, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral account treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 9.50% for 2010 (8.47% for January through June 2009 and 9.50% effective July 1, 2009) on a deemed capital structure of 40% common equity (2009 – 35%). TGVI's allowed ROE was 10.00% for 2010 (9.17% for January through June 2009 and 10.00% effective July 1, 2009) on a deemed capital structure of 40% common equity. TGWI's allowed ROE was 10.00% for 2010 (8.97% for January through June 2009 and 10.00% effective July 1, 2009) on a deemed capital structure of 40% common equity. FortisBC's allowed ROE was 9.90% for 2010 (2009 – 8.87%) on a deemed capital structure of 40% common equity.

Previously the allowed ROE at each of TGI, TGVI, TGWI and FortisBC was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond yields. Effective July 1, 2009 for TGI, TGVI and TGWI and effective January 1, 2010 for FortisBC, 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.

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 9.00% for 2010 (2009 – 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 yields. 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.

2. Nature of Regulation (cont'd)

Newfoundland Power

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

Newfoundland Power operates under COS regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the 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 yields. For 2009 the Company's allowed ROE was 8.95%, as calculated under the automatic adjustment formula, on a deemed capital structure of 45% common equity. However, for 2010 the PUB set Newfoundland Power's allowed ROE at 9.00% on a deemed capital structure of 45% common equity. In April 2010 the PUB approved a change in the automatic adjustment formula. Forecast long-term Canada bond yields are now being used to determine the risk-free rate for calculating the forecast cost of equity used in the formula for 2011 and 2012. The previous approach used a 10-day observation of long-term Canada bond yields as the forecast risk-free rate.

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.

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). 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 deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75% for 2010 (2009 – 9.75%) on a deemed capital structure of 40% common equity. 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.

In November 2010 Maritime Electric signed the PEI Energy Accord (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 will assume responsibility for the cost of 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. 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.

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 2010 (2009 – 8.01%) on a deemed capital structure of 40% common equity effective May 1, 2010. Prior to May 1, 2010, the deemed capital structure was 43.3% common equity (46.7% for January through April 2009 and 43.3% effective May 1, 2009). Effective May 1, 2009, Canadian Niagara Power's electricity distribution rates were rebased using forecast 2009 costs. Prior to May 1, 2009, electricity distribution rates were based upon costs derived from a 2004 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, Algoma Power's allowed ROE was 8.57% on a deemed capital structure of 50% common equity and 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 exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, expiring in 2033. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

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 rate of return on rate base assets ("ROA"). As a result of the June 2008 Final Decision by the PUC, the allowed ROA for Belize Electricity was 10.00% for 2010 (2009 – 10.00%). The allowed ROA, however, has not been achieved due to ongoing regulatory challenges and is expected to be settled upon resolution of these challenges.

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, 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 2010 were set in accordance with the licences, translating into a targeted allowed ROA range of 7.75% to 9.75% (2009 – 9.00% to 11.00%). 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 PPC 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 Governor of the Turks and Caicos Islands, 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 Governor of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2010 calculated the Allowable Operating Profit for 2010 to be $25 million (US$25 million) and the Cumulative Shortfall at December 31, 2010 to be $50 million (US$50 million). Fortis Turks and Caicos exercised its legal right under the Agreements to request an increase in electricity rates, effective May 31, 2010, to begin to recover the Cumulative Shortfall. The requested rate increase was not accepted, but Fortis Turks and Caicos is continuing discussions with the Governor of the Turks and Caicos Islands on the matter. The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses.

3. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation, as described in Note 2. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP 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.

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

Regulatory Assets and Liabilities (cont'd)

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 Canadian Institute of Chartered Accountants ("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 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: (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 reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulator, amortization cost at FortisAlberta, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization cost is recorded 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, 2010, the long-term regulatory liability for asset removal and site restoration costs, net of salvage proceeds, was $339 million (December 31, 2009 – $326 million) (Note 5 *(xviii)*).

As permitted by the regulator, FortisBC and, prior to 2010, the Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. Prior to the fourth quarter of 2009, FortisBC had estimated an amount within amortization cost to represent a provision for asset removal and site restoration costs, net of salvage proceeds. Based on information that became available to the Company in late 2009, FortisBC believes the portion of amortization cost and the related accumulated amortization that had previously been estimated as relating to the provisioning for asset removal and site restoration costs, net of salvage proceeds, is more appropriately presented and disclosed as accumulated amortization rather than as a provision for asset removal and site restoration costs, net of salvage proceeds, in regulatory liabilities. This presentation provides more reliable and relevant information about the effects of regulation on FortisBC. Effective January 1, 2010, as approved by the regulator, the Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, as operating expenses to be recovered from customers in current rates. Actual costs incurred in excess of, or below, the approved amount are to be recorded in a regulatory deferred account for recovery from, or refund to, customers in future rates. During 2010 actual asset removal costs of approximately $10 million were incurred, with $8 million recorded in operating expenses and $2 million deferred as a regulatory asset.

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

FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos recognize asset removal and site restoration costs, net of salvage proceeds, in earnings in the period incurred. These net costs did not have a material impact on the Corporation's 2010 and 2009 consolidated earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and, prior to 2010, the Terasen Gas companies, 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 2010 was approximately $24 million (2009 – $37 million).

Effective January 1, 2010, as approved by the regulator, the Terasen Gas 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 *(x)*).

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

At FortisOntario and Fortis Turks and Caicos, any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets is recognized immediately in earnings.

As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but which 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 over constructed capital assets and amortized over their estimated service lives. In 2010 GEC totalled $57 million (2009 – $57 million).

As required by their respective regulator, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and Caribbean Utilities 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 an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges and AFUDC capitalized during 2010 was $28 million (2009 – $18 million) (Note 20), including an equity component of $15 million (2009 – $9 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

Effective January 1, 2010, as approved by the regulator, FortisAlberta began capitalizing 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 2010 amortization costs of approximately $5 million were capitalized.

Utility capital assets include inventories held for the development, construction and maintenance 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.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2010 amortization costs were reduced by $3 million (2009 – $4 million) for the amortization of the regulatory tax basis adjustment. In the absence of rate regulation, the regulatory tax basis adjustment account and related amortization would not be permitted.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization studies recently completed at the Terasen Gas companies, FortisAlberta and Fortis Turks and Caicos resulted in changes in the estimated service lives of certain utility capital assets during 2010. Amortization rates for 2010 ranged from 0.4% to 33.3% (2009 – 0.4% to 33.3%). The weighted average composite rate of amortization, before reduction for amortization of contributions in aid of construction, for 2010 was 3.5% (2009 – 3.2%).

Effective January 1, 2010, as approved by the regulator, the Terasen Gas companies commenced amortization of utility capital assets the month after the assets were available for use. Prior to 2010 amortization commenced the year following when the utility capital assets became available for use. During 2010 additional amortization costs of approximately $2 million were incurred due to the change in commencement of the amortization.

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

Utility Capital Assets (cont'd)

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:

	2010		2009	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Gas	**4–53**	**30**	10–50	34
Electricity	**5–75**	**27**	5–75	26
Transmission				
Gas	**4–75**	**29**	10–50	33
Electricity	**10–75**	**34**	10–75	34
Generation	**5–75**	**33**	5–75	31
Other	**3–70**	**11**	5–70	13

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. 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 two 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. An amortization study recently completed at the Terasen Gas companies resulted in changes in the estimated service lives of certain intangible assets during 2010.

Amortization rates for 2010 ranged from 1.0% to 25.0% (2009 – 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:

	2010		2009	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**5–10**	**5**	5–10	5
Land, transmission and water rights	**15–65**	**38**	15–61	37
Franchise fees, customer contracts and other	**4–100**	**10**	4–100	6

Notes to Consolidated Financial Statements

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, Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and, prior to 2010, the Terasen Gas companies, 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, Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and, prior to 2010, the Terasen Gas companies, would be recognized in earnings in the period incurred. The loss charged to accumulated amortization in 2010 was approximately $4 million (2009 – $1 million).

Effective January 1, 2010, as required by the regulator, the Terasen Gas 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, any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets is 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, 2010 and 2009.

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 inflow stream, such an asset is tested individually and an impairment is recorded if the future net cash inflows 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 inflows 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. During 2009 Fortis changed the date of the annual goodwill impairment test from July 31 to October 1 to better correspond with the timing of the preparation of the Corporation's and subsidiaries' annual financial budgets. Accordingly, this accounting change was preferable in the Corporation's circumstance. The change in timing of the test did not delay, accelerate or avoid any impairment charge. The Corporation performed the annual goodwill impairment test as at July 31, 2009 and again as at October 1, 2009. The change in the timing of the impairment test had no impact on the consolidated financial statements.

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, 2010. No goodwill impairment provision has been determined for the years ended December 31, 2010 and 2009.

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, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. 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 Terasen Gas companies and Newfoundland Power, pension plan assets are valued at fair value. At the Terasen Gas companies and Newfoundland Power, pension plan assets are valued using the market-related value, 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 Terasen Gas 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 and defined contribution pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 5 *(xv)*). In the absence of rate regulation, deferral account treatment would not be permitted.

Other Post-Employment Benefit and Supplementary Plans

The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, 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.

Additionally, the Corporation, the Terasen Gas companies, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of their executive employees. The accrued benefit obligation and the value of the cost associated with the supplementary and 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. The cost of supplemental pension plans at FortisAlberta is also 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 will be 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 and supplemental pension 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 foreign operations, all of which are self-sustaining and denominated in US dollars or in a currency pegged to the US dollar, are translated at the exchange rate in effect at the balance sheet date. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, BECOL and FortisUS Energy is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00. The exchange rate in effect as at December 31, 2010 was US$1.00=CDN$0.99 (December 31, 2009 – US$1.00=CDN$1.05). 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 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 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.

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 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 Terasen Gas 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 regulatory 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.

Hedging Relationships

As at December 31, 2010, the Corporation's hedging relationships consisted of foreign exchange forward contracts, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

The foreign exchange forward contracts are held by the Terasen Gas companies. During 2010 TGI entered into a foreign exchange forward contract to hedge the cash flow risk related to approximately US$8 million remaining to be paid under a contract for the implementation of a customer information system. TGVI also has a foreign exchange forward contract to hedge the cash flow risk related to approximately US$1 million remaining to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The fair values of the foreign exchange forward contracts are 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 values of the foreign exchange forward contracts at TGI and TGVI is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

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

Hedging Relationships (cont'd)

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 Terasen Gas 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 foreign exchange forward contracts and the natural gas derivatives are estimates of the amounts that the Terasen Gas companies would have to receive or pay to terminate the outstanding contracts as at the balance sheet date. As at December 31, 2010, 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 held US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. The unrealized foreign exchange gains and losses on the US dollar-denominated long-term debt and the partially offsetting unrealized foreign exchange losses and gains on the foreign net investments are 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 Terasen Gas companies, FortisAlberta, FortisBC, 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 deferral accounts specifically 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 income taxes that are expected to be collected or refunded in customer rates once they become payable or receivable (Note 5 *(i)*).

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 is being deferred by Belize Electricity for recovery from customers in future electricity 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 Government of Belize for the terms of its 50-year PPAs.

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.

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's respective regulatory authority. 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, transmission and distribution, 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.

Notes to Consolidated Financial Statements

As required by the respective regulatory authority, revenue from the sale of gas by the Terasen Gas companies and electricity by FortisAlberta, FortisBC, 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 is recognized as monthly billings are issued to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis has been recorded on the consolidated balance sheet as a regulatory liability (Note 5 *(xxiii)*).

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 and, prior to 2010 for certain elements of the transmission costs, FortisAlberta was subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences were subject to deferral account treatment and are either recovered from, or refunded to, customers in future rates. As approved by the regulator, effective January 1, 2010, FortisAlberta is no longer subject to any forecast risk with respect to transmission costs, as all differences between revenue and expenses related to transmission services are subject to deferral account treatment to be recovered from, or refunded to, customers in future rates (Note 5 *(viii)*). 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 costs and revenue associated with the recovery of these costs are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario, as required under OEB regulation. 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. Generally, production from the Corporation's generation facilities is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements.

The leases are primarily of a net nature, with tenants paying basic rental plus a pro-rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue. The escalation of lease rates included in long-term leases is 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.

During 2010 FortisBC obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of polychlorinated biphenyl-contaminated oil from its electrical equipment. As at December 31, 2010, FortisBC has recognized approximately $3 million in AROs, which have been classified as long-term other liabilities (Note 14) with the offset to utility capital assets.

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

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

Asset-Retirement Obligations (cont'd)

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.

Business Combinations

Effective January 1, 2010, the Corporation early adopted CICA Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests*. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree in a business combination results in a different calculation of goodwill with respect to acquisitions on or after January 1, 2010. Such changes include the expensing of acquisition-related costs incurred during a business acquisition, rather than recording them as a capital transaction, and the disallowance of recording restructuring accruals by the acquirer. The adoption of Section 1582 did not have a material impact on the Corporation's consolidated financial statements for the year ended December 31, 2010.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for non-controlling interests in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 resulted in non-controlling interests being presented as components of equity, rather than as liabilities, on the consolidated balance sheet. Also, net earnings and components of other comprehensive income attributable to the owners of the parent company and to non-controlling interests are now separately disclosed on the consolidated statements of earnings and comprehensive income.

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. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Income Producing Properties, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 5 and 30.

4. Future Accounting Changes

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. 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 has elected to opt for the one-year deferral and, therefore, will continue to prepare its consolidated financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis has evaluated the option of adopting United States generally accepted accounting principles ("US GAAP") effective January 1, 2012. Canadian rules allow a reporting issuer to prepare and file its financial statements 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 has developed and initiated a plan to become an SEC Issuer by December 31, 2011. As an SEC Issuer, Fortis will then be permitted to prepare and file its consolidated financial statements in accordance with US GAAP. Barring a change that will provide certainty as to the Corporation's ability to recognize regulatory assets and liabilities under IFRS, Fortis expects to prepare its consolidated financial statements in accordance with US GAAP for all interim and annual periods beginning on or after January 1, 2012.

The adoption of US GAAP in 2012 is expected to result in fewer significant changes in the Corporation's accounting policies as compared to those that may have resulted from the adoption of IFRS. The Corporation's application of Canadian GAAP currently relies on US GAAP for guidance on accounting for rate-regulated activities, which 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, more accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations. Should the Corporation not be successful in becoming an SEC Issuer by December 31, 2011, Fortis will be required to adopt IFRS effective January 1, 2012. In the absence of an accounting standard for rate-regulated activities being established by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities, and could result in significant volatility in the Corporation's consolidated earnings, as recognized under IFRS, from those otherwise recognized under US GAAP or previous Canadian GAAP.

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)*	**2010**	2009	**Remaining recovery period *(Years)***
Future income taxes *(i)*	**$ 568**	$ 514	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**146**	82	1
Rate stabilization accounts – electric utilities *(iii)*	**44**	70	Various
Regulatory OPEB plan assets *(iv)*	**66**	59	Various
Point Lepreau replacement energy deferral *(v)*	**44**	23	To be determined
2010 accrued distribution revenue adjustment rider *(vi)*	**36**	–	1
Deferred energy management costs *(vii)*	**23**	14	1–10
AESO charges deferral *(viii)*	**19**	80	1
Income taxes recoverable on OPEB plans *(ix)*	**18**	18	To be determined
Deferred losses on disposal of utility capital assets *(x)*	**16**	–	To be determined
Deferred development costs for capital *(xi)*	**11**	7	1–20
Deferred operating costs *(xii)*	**11**	–	Various
Deferred costs – smart meters *(xiii)*	**8**	4	To be determined
Deferred lease costs *(xiv)*	**6**	6	13–28
Deferred pension costs *(xv)*	**5**	6	5
Southern Crossing Pipeline tax reassessment *(xvi)*	**–**	7	–
Other regulatory assets *(xvii)*	**51**	57	To be determined
Total regulatory assets	**1,072**	947	
Less: current portion	**(241)**	(221)	1
Long-term regulatory assets	**$ 831**	$ 726	

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

5. Regulatory Assets and Liabilities (cont'd)

Regulatory Liabilities

(in millions)	**2010**	2009	**Remaining settlement period *(Years)***
Asset removal and site restoration provision *(xviii)*	**$ 339**	$ 326	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**60**	44	Various
Rate stabilization accounts – electric utilities *(iii)*	**45**	21	Various
AESO charges deferral *(viii)*	**9**	–	2
PBR incentive liabilities *(xix)*	**8**	15	1–2
Unrecognized net gains on disposal of utility capital assets *(xx)*	**8**	8	To be determined
Deferred interest *(xxi)*	**7**	7	1–3
2010 TGI revenue surplus *(xxii)*	**7**	–	1
Unbilled revenue liability *(xxiii)*	**5**	10	To be determined
Southern Crossing Pipeline deferral *(xxiv)*	**5**	9	1–3
Other regulatory liabilities *(xxv)*	**34**	34	To be determined
Total regulatory liabilities	**527**	474	
Less: current portion	**(60)**	(51)	1
Long-term regulatory liabilities	**$ 467**	$ 423	

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 assets and liabilities 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 – Terasen Gas Companies

The rate stabilization accounts at the Terasen Gas 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 TGI 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 TGI's natural gas commodity derivative instruments. At TGVI a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in fair value of TGVI's natural gas commodity derivative instruments.

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

Prior to 2009 TGVI maintained a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed the allowed ROE as set by the BCUC. During 2009 the RDDA balance was fully recovered as achieved earnings exceeded the allowed ROE. An excess recovery of the RDDA balance was recorded in the Revenue Surplus Account ("RSA"), which captured the revenue surplus that was created during 2009. The BCUC approved the balance in the RSA account as at December 31, 2009 at a forecast amount. The RSA is being returned to customers in rates equally in 2010 and 2011. The difference between the actual 2009 revenue surplus and the approved forecasted amount was transferred to the Rate Stabilization Deferral Account ("RSDA"). The RSDA was approved by the regulator to capture the 2009 revenue surplus in excess of the forecast amount and to accumulate excess costs recovered from customers for providing service or to draw down such costs where earnings differ from the allowed ROE for 2010 and 2011. The RSDA will be refunded to customers in rates in 2012 and beyond as to be determined in the next revenue requirements application of the Terasen Gas companies.

The rate stabilization accounts at the Terasen Gas companies are detailed as follows.

(in millions)	**2010**	2009
Current Regulatory Assets		
CCRA	**$ 91**	$ 40
MCRA	**5**	29
GCVA	**50**	13
	$ 146	$ 82
Current Regulatory Liabilities		
RSAM	**$ 4**	$ 12
RSA	**2**	2
	$ 6	$ 14
Long-Term Regulatory Liabilities		
RSAM	**$ 7**	$ 23
RSA	**–**	2
RSDA	**47**	5
	$ 54	$ 30
Total Regulatory Liabilities	**$ 60**	$ 44

(iii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, 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 four years and is subject to periodic review by the respective regulator.

The balance in Newfoundland Power's weather normalization account as at December 31, 2010 was a net regulatory liability of $3 million (December 31, 2009 – regulatory asset of $6 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, 2010, $8 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 four years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period.

As at December 31, 2010, the $29 million balance in Belize Electricity's rate stabilization account was in a payable position (December 31, 2009 – $20 million) and was not subject to a regulatory return.

As at December 31, 2010, $5 million (December 31, 2009 – $6 million) of the remaining balance of the rate stabilization accounts in a receivable position 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.

(iv) *Regulatory OPEB Plan Assets*

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, 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 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 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, 2010, regulatory OPEB assets at FortisAlberta and FortisBC totalling $13 million (December 31, 2009 – $12 million) were not subject to a regulatory return.

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

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

(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 subject to further review by a commission to be established by the Government of PEI. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(vi) *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 has been approved for collection from customers in 2011. In the absence of rate regulation, revenue would have been $36 million lower in 2010. This balance is not subject to a regulatory return.

(vii) *Deferred Energy Management Costs*

The Terasen Gas companies, FortisBC, Newfoundland Power and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power and Maritime Electric have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from four to ten 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) *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, 2010, the AESO charges deferral account consisted of the 2009 regulatory asset balance of $19 million, which will be collected in customer rates in 2011, and the 2010 regulatory liability balance of $9 million, which is expected to be refunded in customer rates in 2012, subject to regulatory approval. 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.

(ix) *Income Taxes Recoverable on OPEB Plans*

At TGI the regulator allows OPEB plan costs to be collected in customer gas 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 gas rates. In the absence of rate regulation, the income tax would not be deferred.

(x) *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 Terasen Gas companies are recorded in a regulatory deferral account to be recovered from customers in future rates. The recovery of these deferred losses will be determined in the next revenue requirements application of the Terasen Gas companies. Prior to 2010 losses on the retirement or disposal of utility capital assets were recorded against accumulated amortization on the consolidated balance sheet. In the absence of rate regulation, the deferral of losses on the retirement or disposal of utility capital assets would not be permitted.

(xi) *Deferred Development Costs for Capital*

Deferred development costs for capital projects include costs for projects under development at the Terasen Gas 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 TGWI customer appliances from propane to natural gas. A provision of approximately $6 million for costs incurred on the conversion in excess of the amounts previously approved by the regulator was charged to earnings in 2009. During 2010 there was a reversal of approximately $5 million of the provision previously recognized in 2009 due to TGWI receiving a decision from the BCUC allowing these additional costs to be included in a deferral account to be amortized and collected in TGWI customer rates in future years. In the absence of rate regulation, the deferred development costs for capital would be capitalized; however, the ultimate period of amortization would likely differ.

Notes to Consolidated Financial Statements

(xii) *Deferred Operating Costs*
As approved by the regulator, FortisAlberta is permitted to defer certain operating costs that 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 treatment would be permitted.

(xiii) *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 have arisen from 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 into net earnings would likely differ.

(xiv) *Deferred Lease Costs*
FortisBC defers lease costs associated with the Brilliant Terminal Station ("BTS") and Trail office building. The recovery of 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 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 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 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.

(xv) *Deferred Pension Costs*
Deferred pension costs are incremental pension costs arising from Newfoundland Power's 2005 Early Retirement Program that were deferred and are being amortized over a 10-year period that began on April 1, 2005, as ordered by the regulator. In the absence of rate regulation, these costs would have been expensed in 2005.

(xvi) *Southern Crossing Pipeline Tax Reassessment*
The Southern Crossing Pipeline tax reassessment deferral related to an assessment of additional British Columbia Social Services Tax for which TGI had filed an appeal. TGI was successful in its appeal in May 2010 and, accordingly, the Company received a refund of the balance of the assessment.

(xvii) *Other Regulatory Assets*
Other regulatory assets relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Maritime Electric and Caribbean Utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2010, $45 million (December 31, 2009 – $33 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, 2010, $7 million (December 31, 2009 – $9 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

(xviii) *Asset Removal and Site Restoration Provision*
As required by the respective regulator, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, Newfoundland Power and Maritime Electric attributable to asset removal and site restoration costs that are expected to be incurred in the future. 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 these asset removal and site restoration costs, net of salvage proceeds. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

The regulatory liability represents the amount of expected asset removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates, as approved by the respective regulator. Any differences between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in the regulatory liability, with the offset recorded as an adjustment to accumulated amortization.

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

5. Regulatory Assets and Liabilities (cont'd)

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

(xviii) Asset Removal and Site Restoration Provision (cont'd)

During 2010 the amount included in amortization cost associated with the provision for asset removal and site restoration costs was $50 million (2009 – $29 million). During 2010 actual asset removal and site restoration costs, net of salvage proceeds, were $24 million (2009 – $23 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.

(xix) PBR Incentive Liabilities

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow 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). TGI's regulatory PBR incentive liability of $5 million will be refunded to customers during 2011. The majority of FortisBC's regulatory PBR incentive liability has been approved by the BCUC for settlement in 2011, with the remainder expected to be approved for settlement in 2012. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

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

As approved by the regulator, this regulatory liability at the Terasen Gas companies represents the one-time transfer of cumulative unrecognized net gains on disposal of utility capital assets from utility capital asset accumulated amortization. The recovery of this regulatory liability will be determined as part of the Terasen Gas companies' next revenue requirements application. In the absence of rate regulation, the unrecognized net gains on disposal of utility capital assets would have been recognized in earnings as incurred.

(xxi) Deferred Interest

The Terasen Gas companies have interest deferral mechanisms, as approved by the regulator, which accumulate variances between the actual and approved interest rates associated with long-term and short-term borrowings and between 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.

(xxii) 2010 TGI Revenue Surplus

The 2010 revenue surplus deferral account captures amounts collected in customer rates at TGI in excess of certain costs incurred in 2010. The revenue surplus has been approved to be 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.

(xxiii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 3). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis has been recorded on the consolidated balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the regulator. As a result, the $24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on an accrual basis was recorded as a regulatory liability. As ordered by the regulator, Newfoundland Power amortized to earnings the remaining $5 million of this regulatory liability in 2010 (2009 – $5 million). 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. Belize Electricity's unbilled revenue liability of $5 million as at December 31, 2010 (December 31, 2009 – $5 million) was not subject to a regulatory return and the settlement period has not yet been determined.

(xxiv) 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 and, as at December 31, 2010, all of the balance was subject to a regulatory return (December 31, 2009 – $2 million was not subject to a regulatory return). In the absence of rate regulation, the revenue would be recognized in earnings when services are rendered.

(xxv) Other Regulatory Liabilities

Other regulatory liabilities relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2010, $21 million (December 31, 2009 – $11 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, 2010, $10 million (December 31, 2009 – $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)	**2010**	2009
Regulatory assets	**$ (1,046)**	$ (931)
Regulatory liabilities	**(527)**	(474)
Accumulated other comprehensive loss	**45**	30
Opening retained earnings	**(457)**	(377)
Revenue	**$ 341**	$ 462
Energy supply costs	**354**	505
Operating expense	**62**	51
Amortization	**(55)**	(35)
Finance charges	**2**	(3)
Corporate taxes	**40**	24
Net earnings	**$ (62)**	$ (80)

6. Inventories

(in millions)	**2010**	2009
Gas in storage	**$ 148**	$ 159
Materials and supplies	**20**	19
	$ 168	$ 178

During 2010 inventories of $863 million (2009 – $1,022 million) were expensed and reported in energy supply costs on the consolidated statement of earnings. Inventories expensed to operating expenses were $15 million for 2010 (2009 – $14 million), which included $10 million for food and beverage costs at Fortis Properties (2009 – $10 million).

7. Assets Held for Sale

A 10-year Joint-Use Facilities Partnership Agreement ("JUFPA") between Newfoundland Power and Bell Aliant (formerly Aliant Telecom Inc.) expired on December 31, 2010. In 2001 Newfoundland Power purchased Bell Aliant's joint-use poles and related infrastructure under the JUFPA. Bell Aliant has been renting 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. Newfoundland Power and Bell Aliant have signed a new Support Structure Agreement in which Bell Aliant will buy back 40% of all joint-use poles and related infrastructure for approximately $46 million, effective January 1, 2011.

As at December 31, 2010, the Corporation reclassified $45 million to assets held for sale, which represented the estimated sales price less costs to sell the joint-use poles. The Support Structure Agreement is subject to certain closing conditions, including PUB approval. The estimated sales price will be adjusted upon completion of a pole survey in 2011. The sale is expected to close in 2011.

8. Other Assets

(in millions)	**2010**	2009
Deferred pension costs *(Note 22)*	**$ 140**	$ 139
Long-term accounts receivable (due 2040)	**9**	9
Corporate income tax deposit at Maritime Electric	**–**	6
Other assets	**19**	20
	$ 168	$ 174

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

9. Utility Capital Assets

2010 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution					
Gas	**$ 2,467**	**$ (494)**	**$ (183)**	**$ –**	**$ 1,790**
Electricity	**4,588**	**(1,190)**	**(534)**	**(80)**	**2,784**
Transmission					
Gas	**1,328**	**(383)**	**(92)**	**–**	**853**
Electricity	**1,075**	**(278)**	**(18)**	**–**	**779**
Generation	**1,013**	**(284)**	**–**	**–**	**729**
Other	**993**	**(371)**	**–**	**–**	**622**
Assets under construction	**545**	**–**	**–**	**–**	**545**
Land	**100**	**–**	**–**	**–**	**100**
	$ 12,109	**$ (3,000)**	**$ (827)**	**$ (80)**	**$ 8,202**

2009 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,407	$ (442)	$ (182)	$ –	$ 1,783
Electricity	4,369	(1,163)	(503)	(83)	2,620
Transmission					
Gas	1,311	(353)	(84)	–	874
Electricity	994	(259)	(18)	–	717
Generation	982	(281)	–	–	701
Other	938	(343)	(4)	–	591
Assets under construction	320	–	–	–	320
Land	87	–	–	–	87
	$ 11,408	$ (2,841)	$ (791)	$ (83)	$ 7,693

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, 2010, assets under construction associated with larger projects included TGVI's LNG storage facility, FortisBC's Okanagan Transmission Reinforcement Project and the Waneta Expansion.

The cost of utility capital assets under capital lease as at December 31, 2010 was $59 million (December 31, 2009 – $57 million) and related accumulated amortization was $25 million (December 31, 2009 – $24 million).

10. Income Producing Properties

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**

2009

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 490	$ (60)	$ 430
Equipment	70	(29)	41
Tenant inducements	25	(17)	8
Land	64	–	64
Assets under construction	16	–	16
	$ 665	$ (106)	$ 559

11. Intangible Assets

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**

2009

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 314	$ (152)	$ 162
Land, transmission and water rights	121	(12)	109
Franchise fees, customer contracts and other	16	(8)	8
Assets under construction	7	–	7
	$ 458	$ (172)	$ 286

Additions to intangible assets during 2010 were $80 million (2009 – $33 million), approximately $9 million (2009 – $11 million) of which were developed internally. During 2010 fully amortized intangible assets of $35 million (2009 – $49 million) were retired, reducing cost and accumulated amortization.

Included in the cost of land, transmission and water rights as at December 31, 2010 was $62 million (December 31, 2009 – $66 million) not subject to amortization.

As at December 31, 2010, assets under construction primarily related to TGI's Customer Care Enhancement Project and the Waneta Expansion.

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

12. Goodwill

(in millions)	**2010**	2009
Balance, beginning of year	**$ 1,560**	$ 1,575
Foreign currency translation impacts	**(7)**	(22)
Terasen Gas companies	**–**	6
Step acquisition of Caribbean Utilities	**–**	1
Balance, end of year	**$ 1,553**	$ 1,560

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.

During 2009 the Terasen Gas companies recognized an adjustment to goodwill associated with the adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009.

13. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	**2010**	2009
Regulated Utilities			
Terasen Gas Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2009 – 10.71%)	2015 – 2016	**$ 275**	$ 275
Unsecured Debentures –			
6.06% weighted average fixed rate (2009 – 6.12%)	2029 – 2040	**1,520**	1,420
Government loan *(Note 29)*	2010	**–**	4
Obligations under capital leases	2015	**13**	11
FortisAlberta			
Unsecured Debentures –			
5.62% weighted average fixed rate (2009 – 5.74%)	2014 – 2050	**1,059**	934
FortisBC			
Secured Debentures –			
9.12% weighted average fixed rate (2009 – 9.12%)	2012 – 2023	**40**	40
Unsecured Debentures –			
5.84% weighted average fixed rate (2009 – 6.00%)	2014 – 2050	**600**	500
Obligation under capital lease	2032	**25**	26
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.67% weighted average fixed rate (2009 – 7.67%)	2014 – 2039	**464**	469
Maritime Electric			
Secured First Mortgage Bonds –			
7.67% weighted average fixed rate (2009 – 8.10%)	2016 – 2038	**137**	152
FortisOntario			
Unsecured Senior Notes – 7.09% fixed rate	2018	**52**	52
Belize Electricity (Note 26)			
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate (2009 – 10.35%)	2012 – 2027	**34**	36
Other loans –			
4.63% weighted average fixed rate (2009 – 5.23%)	2015	**6**	7
Other variable interest rate loans	2011 – 2015	**10**	15
Caribbean Utilities			
Unsecured US Senior Loan Notes –			
6.28% weighted average fixed rate (2009 – 6.31%)	2013 – 2024	**179**	203

Notes to Consolidated Financial Statements

(in millions)	Maturity Date	**2010**	2009
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. loan – 4.79% weighted average fixed and variable rate (2009 – 5.03%)	2013 – 2016	**$ 8**	$ 10
US First Caribbean International Bank loan – 5.65% fixed rate	2015	**2**	3
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**3**	4
Non-Regulated – Fortis Properties			
Secured:			
First mortgages – 7.21% weighted average fixed rate (2009 – 6.89%)	2012 – 2017	**139**	193
Senior Notes – 7.32% fixed rate	2019	**13**	15
Unsecured:			
Non-revolving variable interest rate credit facilities	2010	**–**	3
Corporate – Fortis and Terasen			
Unsecured:			
Debentures – 6.14% weighted average fixed rate (2009 – 6.44%)	2014 – 2039	**326**	426
US Senior Notes – 5.49% weighted average fixed rate (2009 – 6.23%)	2014 – 2040	**547**	368
US Subordinated Convertible Debentures – 5.50% weighted average fixed rate (2009 – 5.50%)	2016	**37**	39
Capital Securities – 8.00% fixed rate	2010	**–**	126
Long-term classification of credit facility borrowings *(Note 28)*		**218**	208
Total long-term debt and capital lease obligations		**5,707**	5,539
Less: Deferred financing costs		**(42)**	(39)
Less: Current installments of long-term debt and capital lease obligations		**(56)**	(224)
		$ 5,609	$ 5,276

As identified in the table above, certain long-term debt instruments held by FortisBC, 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.

The purchase money mortgages of the Terasen Gas companies are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $425 million.

Regulated Utilities

FortisBC 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 8.63%.

Belize Electricity's unsecured debentures can be called by the Company at any time after certain dates until maturity by giving holders not more than 60 days' nor less than 30 days' written notice and are repayable at the option of the holders at any time on or after certain dates by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

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.

Corporate – Fortis and Terasen

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 unsecured US subordinated convertible debentures, due 2016, are redeemable by Fortis at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's common shares at $28.95 per share (US$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

Notes to Consolidated Financial Statements

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

Corporate – Fortis and Terasen (cont'd)

The unsecured US subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the consolidated financial statements in their component parts. The liability and equity components are classified separately on the consolidated balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $5 million as at December 31, 2010 (December 31, 2009 – $5 million).

In April 2010 Terasen 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 right 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)*
2011	$ 56	$ –	$ 56
2012	104	165	269
2013	114	–	114
2014	415	277	692
2015	103	–	103
Thereafter	3,840	633	4,473

14. Other Liabilities

(in millions)	**2010**	2009
OPEB plan liabilities *(Note 22)*	**$ 159**	$ 145
Defined benefit liabilities *(Note 22)*	**37**	34
Waneta Partnership promissory note	**42**	–
Deferred gains on the sale of natural gas transmission and distribution assets	**38**	42
Defined contribution pension liabilities – unfunded	**11**	10
DSU and PSU liabilities *(Note 17)*	**8**	5
Customer deposits	**6**	6
Deferred payment	**–**	46
Other liabilities	**7**	7
	$ 308	$ 295

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million but was discounted at October 1, 2010 to its present value. As at December 31, 2010, its present value was $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 transmission and distribution 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 29.

The unfunded defined contribution pension liabilities relate to supplementary employee retirement plans at the Corporation and its Canadian operating subsidiaries for which benefits are based upon employee compensation.

The deferred payment resulted from Terasen's acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of $52 million but was discounted at May 17, 2007 to its present value. As at December 31, 2010, its present value was $49 million (December 31, 2009 – $46 million). The deferred payment has been classified as current as at December 31, 2010 and is included in accounts payable and accrued charges on the consolidated balance sheet. The payment is due on December 31, 2011, or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants that may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

Other liabilities primarily include AROs at FortisBC 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			**2010**		2009	
First Preference Shares	Annual Dividend Per Share *($)*	Classification	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Series C	1.3625	Debt	**5,000,000**	**$ 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**	–	–
Total classified as equity			**24,200,000**	**$ 592**	14,200,000	$ 347

[(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. 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. For each five-year period after this date, the holders of First Preference Shares, Series G and Series H 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	**2010**		2009	
	Number of Shares ***(in thousands)***	**Amount** ***(in millions)***	Number of Shares *(in thousands)*	Amount *(in millions)*
Common shares	**174,393**	**$ 2,578**	171,256	$ 2,497

Common shares issued during the year were as follows:

	2010		2009	
	Number of Shares ***(in thousands)***	**Amount** ***(in millions)***	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**171,256**	**$ 2,497**	169,191	$ 2,449
Consumer Share Purchase Plan	**51**	**1**	56	2
Dividend Reinvestment Plan	**2,100**	**59**	1,204	29
Employee Share Purchase Plan	**193**	**5**	321	8
Stock Option Plans	**793**	**16**	484	9
Balance, end of year	**174,393**	**$ 2,578**	171,256	$ 2,497

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.

The Corporation amended and restated its Dividend Reinvestment Plan ("DRIP") to provide a 2% discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2010, 4.0 million (December 31, 2009 – 7.2 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, DRIP and stock option plans.

As at December 31, 2010, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26.0 million, respectively (December 31, 2009 – 1.4 million and 26.0 million, respectively).

As at December 31, 2010, $3 million (December 31, 2009 – $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 172.9 million for 2010 and 170.2 million for 2009.

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

EPS were as follows:

	2010			2009		
	Earnings ***(in millions)***	**Weighted Average Shares** ***(in millions)***	**EPS**	Earnings *(in millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**$ 285**	**172.9**	**$ 1.65**	$ 262	170.2	$ 1.54
Effect of potential dilutive securities:						
Stock Options	**–**	**0.9**		–	0.7	
Preference Shares *(Notes 15 and 20)*	**17**	**11.9**		17	13.9	
Convertible Debentures	**2**	**1.4**		2	1.4	
	$ 304	**187.1**		$ 281	186.2	
Deduct anti-dilutive impacts:						
Convertible Debentures	**–**	**–**		(2)	(1.4)	
Diluted EPS	**$ 304**	**187.1**	**$ 1.62**	$ 279	184.8	$ 1.51

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, 2010, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan ("ESOP"). The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the ESOP and the former Directors' Stock Option Plan. The ESOP will cease to exist when all outstanding options issued under this plan are exercised or expire in or before 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 ESOP and 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	**2010**	2009
Options outstanding, beginning of year	**4,693,493**	4,140,462
Granted	**892,744**	1,037,156
Cancelled	**(93,864)**	–
Exercised	**(792,170)**	(484,125)
Options outstanding, end of year	**4,700,203**	4,693,493
Options vested, end of year	**2,541,374**	2,546,159
Weighted Average Exercise Prices		
Options outstanding, beginning of year	**$ 21.83**	$ 21.04
Granted	**27.36**	22.29
Cancelled	**25.68**	–
Exercised	**17.61**	16.08
Options outstanding, end of year	**23.52**	21.83

Details of stock options outstanding and vested as at December 31, 2010 were as follows:

Number of Options Outstanding	**Number of Options Vested**	**Exercise Price**	**Expiry Date**
34,212	34,212	$ 9.57	2011
65,038	65,038	$ 12.03	2012
179,678	179,678	$ 12.81	2013
355,269	355,269	$ 15.28	2014
10,000	10,000	$ 15.23	2014
1,031	1,031	$ 14.55	2014
378,138	378,138	$ 18.40	2015
28,000	28,000	$ 18.11	2015
14,708	14,708	$ 20.82	2015
410,292	410,292	$ 22.94	2016
521,726	384,885	$ 28.19	2014
122,769	92,127	$ 25.76	2014
761,844	384,348	$ 28.27	2015
945,662	203,648	$ 22.29	2016
871,836	–	$ 27.36	2017
4,700,203	2,541,374		

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December 31, 2010 and 2009

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

Stock Options (cont'd)

The weighted average exercise price of stock options vested as at December 31, 2010 was $21.57.

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

Dividend yield *(%)*	3.66
Expected volatility *(%)*	25.1
Risk-free interest rate *(%)*	2.54
Weighted average expected life *(years)*	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, 2010 (2009 – $3 million).

Directors' DSU Plan

The Corporation's Directors' DSU Plan is an optional vehicle 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	**2010**	2009
DSUs outstanding, beginning of year	**116,904**	100,617
Granted	**24,426**	30,336
Granted – notional dividends reinvested	**5,621**	5,375
DSUs paid out	**–**	(19,424)
DSUs outstanding, end of year	**146,951**	116,904

For the year ended December 31, 2010, expense of $2 million (2009 – $1 million) was recorded in relation to the DSU Plan.

During 2009 19,424 DSUs were paid out to retired members of the Board of Directors of Fortis at a weighted average price of $26.15 per DSU.

As at December 31, 2010, the total liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $33.98, for a total of approximately $5 million (December 31, 2009 – $3 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	**2010**	2009
PSUs outstanding, beginning of year	**98,133**	85,547
Granted	**60,000**	40,000
Granted – notional dividends reinvested	**5,017**	3,939
PSUs paid out	**(21,742)**	(31,353)
PSUs outstanding, end of year	**141,408**	98,133

In May 2010 21,742 PSUs were paid out to the President and CEO of the Corporation at $27.48 per PSU. The payout was made upon the three-year maturation period in respect of the PSU grant made in May 2007 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, 2010, expense of $2 million (2009 – $1 million) was recorded in relation to the PSU Plan.

As at December 31, 2010, the total liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $33.98, for a total of approximately $3 million (December 31, 2009 – $2 million), and is included in other liabilities (Note 14).

18. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 3.

	2010		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Unrealized foreign currency translation losses, net of hedging activities and tax	**$ (78)**	**$ (12)**	**$ (90)**
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(5)**	**1**	**(4)**
Accumulated other comprehensive loss	**$ (83)**	**$ (11)**	**$ (94)**

	2009		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	$ (46)	$ (32)	$ (78)
(Losses) gains on derivative instruments designated as cash flow hedges, net of tax	(1)	1	–
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	(5)	–	(5)
Accumulated other comprehensive loss	$ (52)	$ (31)	$ (83)

During 2010 unrealized foreign currency translation losses of $33 million (2009 – $90 million) were recorded in accumulated other comprehensive loss related to the Corporation's net investment in foreign currency-denominated self-sustaining foreign operations. These unrealized foreign currency translation losses were partially offset by the effective portion of unrealized after-tax gains of $21 million (2009 – $58 million) related to the translation of corporately held US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

19. Non-Controlling Interests

(in millions)	**2010**	2009
Caribbean Utilities	**$ 73**	$ 77
Waneta Partnership	**44**	–
Belize Electricity	**38**	39
Preference shares of Newfoundland Power	**7**	7
	$ 162	$ 123

20. Finance Charges

(in millions)	2010	2009
Interest – Long-term debt and capital lease obligations	**$ 352**	$ 351
– Short-term borrowings	**9**	10
AFUDC *(Note 3)*	**(28)**	(18)
Dividends on preference shares *(Notes 15 and 16)*	**17**	17
	$ 350	$ 360

21. Corporate Taxes

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

(in millions)	2010	2009
Future income tax liability (asset)		
Utility capital assets	**$ 551**	$ 493
Income producing properties	**26**	26
Intangible assets	**20**	28
Regulatory assets	**78**	84
Other assets and liabilities (net)	**2**	9
Regulatory liabilities	**(64)**	(64)
Loss carryforwards	**(23)**	(31)
Unrealized foreign currency translation gains on long-term debt	**9**	5
Share issue and debt financing costs	**–**	(2)
Net future income tax liability	**$ 599**	$ 548
Current future income tax asset	**$ (14)**	$ (29)
Current future income tax liability	**6**	24
Long-term future income tax asset	**(16)**	(17)
Long-term future income tax liability	**623**	570
Net future income tax liability	**$ 599**	$ 548

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

(in millions)	2010	2009
Canadian		
Current taxes	**$ 68**	$ 43
Future income taxes	**49**	42
Less regulatory adjustment	**(50)**	(38)
	(1)	4
Total Canadian	**$ 67**	$ 47
Foreign		
Current taxes	**$ 2**	$ 1
Future income taxes	**(2)**	1
Total Foreign	**–**	2
Corporate taxes	**$ 67**	$ 49

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory 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)	**2010**	2009
Combined Canadian federal and provincial statutory income tax rate	**32.0%**	33.0%
Statutory income tax rate applied to earnings before corporate taxes	**$ 125**	$ 113
Preference share dividends	**6**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(15)**	(16)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(11)**	(8)
Items capitalized for accounting purposes but expensed for income tax purposes	**(39)**	(38)
Difference between capital cost allowance and amounts claimed for accounting purposes	**(4)**	1
Non-deductible expenses	**8**	3
Other	**(3)**	(12)
Corporate taxes	**$ 67**	$ 49
Effective tax rate	**17.2%**	14.4%

As at December 31, 2010, the Corporation had approximately $101 million (December 31, 2009 – $126 million) in non-capital and capital loss carryforwards, of which $18 million (December 31, 2009 – $18 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2030.

22. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, 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 market-related value or fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, the Terasen Gas companies, Newfoundland Power and Caribbean Utilities, and as at September 30 of each year for FortisAlberta, FortisBC, FortisOntario and Algoma Power. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2008 for the Corporation, Newfoundland Power and Caribbean Utilities; as of July 1, 2009 for Algoma Power; as of December 31, 2009 for the Terasen Gas companies (covering non-unionized employees) and FortisOntario; and as of December 31, 2010 for the Terasen Gas companies (covering unionized employees), FortisAlberta and FortisBC, which will be completed during 2011. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation of each plan.

The Corporation's consolidated defined benefit pension plan asset allocation was as follows:

Plan assets as at December 31

(%)	**2010**	2009
Canadian equities	**45**	47
Fixed income	**41**	39
Foreign equities	**9**	9
Real estate	**5**	5
	100	100

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

22. 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:

	2010			2009		
(in millions)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	$ 337	$ 285	$ (52)	$ 282	$ 257	$ (25)
FortisAlberta	28	22	(6)	23	19	(4)
FortisBC	143	106	(37)	127	100	(27)
Newfoundland Power	252	269	17	222	243	21
FortisOntario (1)	23	21	(2)	21	20	(1)
Algoma Power	19	15	(4)	17	15	(2)
Caribbean Utilities	6	4	(2)	5	3	(2)
Fortis	5	5	–	4	4	–
Total	$ 813	$ 727	$ (86)	$ 701	$ 661	$ (40)

(1) Covers eligible employees of Canadian Niagara Power

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	2010	2009	2010	2009	2010	2009
Change in accrued benefit obligation						
Balance, beginning of year	$ 701	$ 613	$ 44	$ 41	$ 183	$ 169
Liability associated with acquisitions	–	17	–	–	–	4
Current service costs	14	11	1	1	4	4
Employee contributions	11	9	–	–	–	–
Interest costs	43	40	2	2	12	11
Benefits paid	(34)	(34)	(2)	(2)	(5)	(4)
Actuarial loss	83	45	5	2	27	16
Past service costs/plan amendments	(5)	–	–	–	(15)	(17)
Balance, end of year	$ 813	$ 701	$ 50	$ 44	$ 206	$ 183
Change in value of plan assets						
Balance, beginning of year	$ 661	$ 579	$ –	$ –	$ –	$ –
Assets associated with acquisitions	–	15	–	–	–	–
Actual return on plan assets	67	71	–	–	–	–
Benefits paid	(34)	(34)	(2)	(2)	(5)	(4)
Employee contributions	11	9	–	–	–	–
Employer contributions	22	21	2	2	5	4
Balance, end of year	$ 727	$ 661	$ –	$ –	$ –	$ –
Funded status						
Deficit, end of year	$ (86)	$ (40)	$ (50)	$ (44)	$ (206)	$ (183)
Unamortized net actuarial loss	225	172	6	1	66	40
Unamortized past service costs	(1)	6	–	1	(31)	(17)
Unamortized transitional obligation	7	7	1	1	12	15
Employer contributions after measurement date	1	1	–	–	–	–
Accrued benefit asset (liability), end of year	$ 146	$ 146	$ (43)	$ (41)	$ (159)	$ (145)
Deferred pension costs *(Note 8)*	$ 148	$ 147	$ (8)	$ (8)	$ –	$ –
Defined benefit liabilities *(Note 14)*	(2)	(1)	(35)	(33)	–	–
OPEB plan liabilities *(Note 14)*	–	–	–	–	(159)	(145)
	$ 146	$ 146	$ (43)	$ (41)	$ (159)	$ (145)

Notes to Consolidated Financial Statements

(in millions)	Defined Benefit Pension Plans Funded 2010	2009	Supplementary Defined Benefit Plans Unfunded 2010	2009	OPEB Plans Unfunded 2010	2009
Components of net benefit cost						
Current service costs	**$ 14**	$ 11	**$ 1**	$ 1	**$ 4**	$ 4
Interest costs	**43**	40	**2**	2	**12**	11
Actual return on plan assets	**(67)**	(71)	**–**	–	**–**	–
Actuarial loss	**83**	45	**5**	2	**27**	16
Past service costs/plan amendments	**(5)**	–	**–**	–	**(15)**	(17)
Costs arising in the year	**68**	25	**8**	5	**28**	14
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**21**	25	**–**	–	**–**	–
Actuarial loss	**(73)**	(42)	**(4)**	(2)	**(25)**	(14)
Past service costs	**6**	1	**–**	–	**13**	16
Transitional obligation and plan amendments	**–**	–	**–**	1	**2**	2
Regulatory adjustment	**(1)**	1	**–**	–	**(7)**	(6)
Net benefit cost	**$ 21**	$ 10	**$ 4**	$ 4	**$ 11**	$ 12
Significant assumptions						
Weighted average discount rate during the year *(%)*	**6.16**	6.62	**6.19**	6.65	**6.27**	6.72
Weighted average discount rate as at December 31 *(%)*	**5.37**	6.16	**5.41**	6.19	**5.38**	6.27
Weighted average expected long-term rate of return on plan assets *(%)*	**6.88**	7.05	**–**	–	**–**	–
Weighted average rate of compensation increase *(%)*	**3.70**	3.60	**3.64**	3.52	**3.72**	3.68
Weighted average health-care cost trend increase as at December 31 *(%)*	**–**	–	**–**	–	**6.53**	6.34
Expected average remaining service life of active employees *(years)*	**3–15**	4–15	**5–11**	3–11	**10–17**	9–17

For 2010 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	**$ 24**	**$ (20)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

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 2010 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.

(Decrease) Increase *(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	**$ (4)**	**$ 3**	**$ –**	**$ 32**
Impact of decreasing the rate of return assumption by 100 basis points	**4**	**(4)**	**–**	**(30)**
Impact of increasing the discount rate assumption by 100 basis points	**(8)**	**7**	**(1)**	**(110)**
Impact of decreasing the discount rate assumption by 100 basis points	**10**	**(9)**	**1**	**137**

[(1)] At the Terasen Gas companies and FortisBC, the methodology for determining the pension indexing assumption, which impacts the measurement of the accrued benefit pension obligation, is based on the excess 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 2010 the Corporation expensed $13 million (2009 – $12 million) related to defined contribution pension plans.

23. Business Acquisitions

2009

REGULATED ELECTRIC UTILITY

a. Algoma Power

In October 2009 FortisOntario acquired all of the issued and outstanding common shares of Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for aggregate cash consideration of approximately $75 million including acquisition costs, initially financed through drawings on the Corporation's committed credit facility.

Algoma Power owns and operates an electric distribution system in an area adjacent to Sault Ste. Marie, Ontario. The acquisition has been accounted for using the purchase method, whereby the financial results of Algoma Power have been included in the consolidated financial statements of Fortis commencing October 2009. The financial results of Algoma Power have been included in the Regulated Electric Utilities – Other Canadian segment.

Algoma Power is regulated by the OEB and, thus, its determination of revenue and earnings is based on regulated rates of return that are applied to historic values, which do not change with a change of ownership. Therefore, for all of the individual assets and liabilities associated with Algoma Power, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers. Accordingly, the book value of the assets and liabilities of Algoma Power has been assigned as fair value for the purchase price allocation.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition.

(in millions)	Total
Fair value assigned to net assets:	
Current assets	$ 9
Utility capital assets	49
Intangible assets	14
Regulatory assets	4
Other assets	2
Current liabilities	(4)
Regulatory liabilities	(1)
Other liabilities	(3)
	70
Cash	5
	$ 75

NON-REGULATED – FORTIS PROPERTIES

b. Holiday Inn Select Windsor

In April 2009 Fortis Properties purchased the Holiday Inn Select Windsor in Ontario for an aggregate cash purchase price of approximately $7 million, including acquisition costs. 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 April 2009.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)	Total
Fair value assigned to net assets:	
Income producing properties	$ 7

24. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2010 *($ millions)*	**Terasen Gas Companies – Canadian**	Fortis Alberta	Fortis BC	NF Power	Other Canadian [1]	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation [2]**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,547**	388	266	555	331	**1,540**	**335**	**36**	**226**	**30**	**(50)**	**3,664**
Energy supply costs	**863**	–	73	358	215	**646**	**201**	**1**	**–**	**–**	**(25)**	**1,686**
Operating expenses	**288**	141	73	62	45	**321**	**48**	**9**	**151**	**16**	**(5)**	**828**
Amortization	**108**	126	41	47	23	**237**	**36**	**4**	**18**	**7**	**–**	**410**
Operating income	**288**	121	79	88	48	**336**	**50**	**22**	**57**	**7**	**(20)**	**740**
Finance charges	**113**	54	32	36	21	**143**	**17**	**–**	**24**	**73**	**(20)**	**350**
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	1,191	646	**5,244**	**779**	**324**	**576**	**505**	**(397)**	**11,350**
Total assets	**5,227**	2,371	1,484	1,191	709	**5,755**	**913**	**324**	**576**	**505**	**(397)**	**12,903**
Gross capital expenditures [3]	**253**	379	139	78	48	**644**	**72**	**84**	**19**	**1**	**–**	**1,073**
Year ended December 31, 2009 *($ millions)*												
Revenue	1,663	331	253	527	285	1,396	339	39	219	27	(40)	3,643
Energy supply costs	1,022	–	72	346	183	601	192	2	–	–	(18)	1,799
Operating expenses	268	132	70	52	38	292	54	11	146	14	(6)	779
Amortization	102	94	37	45	19	195	37	5	17	8	–	364
Operating income	271	105	74	84	45	308	56	21	56	5	(16)	701
Finance charges	121	50	32	35	19	136	16	2	22	79	(16)	360
Corporate tax expense (recovery)	33	(5)	5	16	6	22	2	3	10	(21)	–	49
Net earnings (loss)	117	60	37	33	20	150	38	16	24	(53)	–	292
Non-controlling interests	–	–	–	1	–	1	11	–	–	–	–	12
Preference share dividends	–	–	–	–	–	–	–	–	–	18	–	18
Net earnings (loss) attributable to common equity shareholders	117	60	37	32	20	149	27	16	24	(71)	–	262
Goodwill	908	227	221	–	63	511	141	–	–	–	–	1,560
Identifiable assets	4,086	1,892	1,141	1,165	618	4,816	799	200	576	491	(389)	10,579
Total assets	4,994	2,119	1,362	1,165	681	5,327	940	200	576	491	(389)	12,139
Gross capital expenditures [3]	246	407	115	74	46	642	92	14	26	4	–	1,024

(1) Includes Algoma Power from October 2009, the date of acquisition by FortisOntario

(2) Results reflect the expiry, on April 30, 2009, at the end of a 100-year term, of the 75 MW of water-right entitlement associated with the Rankine hydroelectric generating facility at Niagara Falls. Results also reflect contribution from the Vaca hydroelectric generating facility in Belize, which was commissioned in March 2010, and the Waneta Partnership, which was established in October 2010.

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

24. Segmented Information (cont'd)

Inter-segment 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 inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31 were as follows:

(in millions)	2010	2009
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	$ 24	$ 17
Sales from Fortis Generation to Other Canadian Electric Utilities	1	1
Sales from Newfoundland Power to Fortis Properties	4	4
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	1	1
Corporate to Regulated Electric Utilities – Caribbean	3	3
Corporate to Fortis Generation	4	3
Corporate to Fortis Properties	12	8

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

(in millions)	2010	2009
Inter-segment borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	$ 50	$ 75
Corporate to Regulated Electric Utilities – Caribbean	60	47
Corporate to Fortis Generation	51	59
Corporate to Fortis Properties	219	172
Other inter-segment assets	17	36
Total inter-segment eliminations	$ 397	$ 389

25. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	2010	2009
Interest paid	$ 358	$ 357
Income taxes paid	51	85

26. 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 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 issues. 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, 2010 compared to December 31, 2009 is presented in the following table.

	2010		2009	
	(in millions)	(%)	(in millions)	(%)
Total debt and capital lease obligations (net of cash) [1]	$ 5,914	58.4	$ 5,830	60.2
Preference shares [2]	912	9.0	667	6.9
Common shareholders' equity	3,305	32.6	3,193	32.9
Total [3]	$ 10,131	100.0	$ 9,690	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, 2010, the Corporation and its subsidiaries, except for certain debt at Belize Electricity and the Exploits Partnership, as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application in June 2008, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $5 million (BZ$9 million) as at December 31, 2010.

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 $58 million as at December 31, 2010 (December 31, 2009 – $59 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 30 for further information on the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 28.

27. Financial Instruments

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

	2010		2009	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents [(1)]	**$ 109**	**$ 109**	$ 85	$ 85
Loans and receivables				
Trade and other accounts receivable [(1) (2) (3)]	**655**	**655**	595	595
Other long-term receivables [(1) (3) (4)]	**15**	**15**	16	16
Other financial liabilities				
Short-term borrowings [(1) (3)]	**358**	**358**	415	415
Trade and other accounts payable [(1) (3) (5)]	**786**	**786**	730	730
Dividends payable [(1) (3)]	**54**	**54**	3	3
Customer deposits [(1) (3) (6)]	**6**	**6**	6	6
Waneta Partnership promissory note [(6) (7)]	**42**	**40**	–	–
Long-term debt, including current portion [(8) (9)]	**5,669**	**6,431**	5,502	5,906
Preference shares, classified as debt [(8) (10)]	**320**	**344**	320	348

(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 other assets on the consolidated balance sheet
(5) Included in accounts payable and accrued charges on the consolidated balance sheet
(6) Included in other liabilities on the consolidated balance sheet
(7) Carrying value is a discounted present value.
(8) Carrying value is measured at amortized cost using the effective interest rate method.
(9) Carrying value as at December 31, 2010 excludes unamortized deferred financing costs of $42 million (December 31, 2009 – $39 million) and capital lease obligations of $38 million (December 31, 2009 – $37 million).
(10) 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 $615 million as at December 31, 2010 (December 31, 2009 – carrying value of $347 million; fair value of $356 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.

Notes to Consolidated Financial Statements

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27. Financial Instruments (cont'd)

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, 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 market 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 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.

	2010				2009	
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 contracts [(1)] [(2)]	**< 1.5**	**2**	**$ –**	**$ –**	$ –	$ –
Natural gas derivatives: [(1)] [(3)]						
Swaps and options	**Up to 4**	**163**	**(162)**	**(162)**	(119)	(119)
Gas purchase contract premiums	**Up to 3**	**74**	**(5)**	**(5)**	(3)	(3)

[(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.
[(2)] The fair values of the foreign exchange forward contracts were recorded in accounts payable as at December 31, 2010 and accounts receivable as at December 31, 2009.
[(3)] The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2010 and 2009.

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.

28. 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 third party 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, 2010, its gross credit risk exposure was approximately $115 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $2 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 Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the Terasen Gas companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the Terasen Gas 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.

Notes to Consolidated Financial Statements

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, 2010 (December 31, 2009 – $17 million), excluding derivative financial instruments recorded in accounts receivable as at December 31, was as follows:

(in millions)	**2010**	2009
Not past due	**$ 584**	$ 527
Past due 0–30 days	**56**	52
Past due 31–60 days	**9**	8
Past due 61 days and over	**6**	8
	$ 655	$ 595

As at December 31, 2010, other long-term receivables of $15 million (included in other assets) will be received over the next five years and thereafter, with $1 million expected to be received in 2011, $3 million over 2012 and 2013, $1 million over 2014 and 2015 and $10 million due after 2015.

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 $250 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, 2010, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.1 billion, of which approximately $1.4 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25% of these facilities.

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, 2010**	Total as at December 31, 2009
Total credit facilities	$ 645	$ 1,451	$ 13	**$ 2,109**	$ 2,153
Credit facilities utilized:					
Short-term borrowings	–	(351)	(7)	**(358)**	(415)
Long-term debt *(Note 13)* [(1)]	(165)	(53)	–	**(218)**	(208)
Letters of credit outstanding	(1)	(122)	(1)	**(124)**	(100)
Credit facilities unused	$ 479	$ 925	$ 5	**$ 1,409**	$ 1,430

(1) As at December 31, 2010, credit facility borrowings classified as long-term debt included $16 million (December 31, 2009 – $13 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at December 31, 2010 and December 31, 2009, 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.

28. Financial Risk Management (cont'd)

Liquidity Risk (cont'd)

Corporate and Other

Terasen has a $30 million unsecured committed revolving credit facility, maturing May 2011, that is available for general corporate purposes.

Fortis has a $600 million unsecured committed revolving credit facility, maturing May 2012, and a $15 million unsecured demand credit facility. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

Regulated Utilities

TGI has a $500 million unsecured committed revolving credit facility, maturing August 2013. TGVI has a $300 million unsecured committed revolving credit facility, maturing May 2012. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes. TGVI also has a $20 million subordinated 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 $200 million unsecured committed revolving credit facility, maturing May 2012, utilized to finance capital expenditures and for general corporate purposes. With the consent of the lenders, the amount of the facility can be increased to $250 million. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2011 and the remaining $100 million matures May 2013. 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 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 2013, and a $20 million demand credit facility.

Maritime Electric has a $60 million unsecured committed revolving credit facility, which matures annually in March, 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 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 an 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.

Belize Electricity has an unsecured BZ$1 million ($0.5 million) and a secured BZ$5.5 million ($3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank (Belize) Limited, respectively.

Fortis Properties

Fortis Properties has a $13 million secured revolving demand credit facility utilized for general corporate purposes.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2010, 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 and the significant reduction in external debt at Terasen, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2010.

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	$ 358	$ –	$ –	$ –	**$ 358**
Trade and other accounts payable	786	–	–	–	**786**
Natural gas derivatives [(1)]	104	49	8	–	**161**
Foreign exchange forward contracts [(2)]	5	4	–	–	**9**
Dividends payable	54	–	–	–	**54**
Customer deposits [(3)]	–	3	1	2	**6**
Waneta Partnership promissory note [(4)]	–	–	–	72	**72**
Long-term debt, including current portion [(5)]	54	377	789	4,449	**5,669**
Interest obligations on long-term debt	347	682	622	5,055	**6,706**
Preference shares, classified as debt	–	123	–	197	**320**
Dividend obligations on preference shares, classified as finance charges	17	32	19	7	**75**
Total	$ 1,725	$ 1,270	$ 1,439	$ 9,782	**$ 14,216**

[(1)] Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2010 at $167 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, 2010 at less than $1 million.
[(3)] Customer deposits were recorded in other liabilities as at December 31, 2010.
[(4)] Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in other liabilities at present value as at December 31, 2010 at $42 million.
[(5)] Excludes deferred financing costs of $42 million and capital lease obligations of $38 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 or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00=US$1.00.

As at December 31, 2010, the Corporation's corporately issued US$590 million (December 31, 2009 – US$390 million) long-term debt had been designated as a hedge of almost all of the Corporation's foreign net investments. As at December 31, 2010, the Corporation had approximately US$7 million (December 31, 2009 – US$174 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held 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 foreign net investments, which are also recorded in other comprehensive income.

A 5% appreciation or depreciation of the US dollar relative to the Canadian dollar would have increased or decreased earnings by approximately $2 million for the year ended December 31, 2010 (2009 – $1 million) and would have decreased or increased other comprehensive income by $25 million for the year ended December 31, 2010 (2009 – $20 million). This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense and earnings' streams from the Corporation's foreign subsidiaries 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 $30 million for the year ended December 31, 2010 (2009 – $31 million).

28. Financial Risk Management (cont'd)

Market Risk (cont'd)

Foreign Exchange Risk (cont'd)

US dollar payments under contracts for the implementation of a customer information system at TGI and the construction of an LNG storage facility at TGVI expose these utilities to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGI and TGVI have entered into foreign exchange forward contracts to hedge this exposure. As at December 31, 2010, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar, as it affects the measurement of the fair value of the foreign exchange forward contracts, 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, 2010 (2009 – $1 million). Furthermore, TGI and TGVI have regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contracts 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 and, during 2010, Fortis Properties was party to one interest rate swap agreement that effectively fixed the interest rate on a variable-rate borrowing. During the third quarter of 2010, Fortis Properties' interest rate swap agreement matured.

A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $4 million for the year ended December 31, 2010 (2009 – $3 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, 2010 (2009 – $1 million). Furthermore, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund 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, 2010 (2009 – $1 million).

Commodity Price Risk

The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is 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 Terasen Gas 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. On an annual basis, TGI and TGVI each file a Price Risk-Management Plan ("PRMP") that seeks approval for the Companies' natural gas commodity hedging plan for the next three years for TGI and the next five years for TGVI. During the third quarter of 2010, the BCUC denied the most recent PRMP application filed by the Terasen Gas companies earlier in 2010 and directed the Companies to undertake a review of the primary objectives of the PRMP. As a result, the Terasen Gas companies have completed their hedging program for the current winter period related to previously approved PRMPs, but have not entered into any additional natural gas derivatives for any subsequent periods. In January 2011 TGI filed its review of the PRMP objectives with the BCUC related to its gas commodity hedging plan and also submitted a 2011–2014 PRMP. TGVI plans to file an updated PRMP by April 2011.

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 $63 million for the year ended December 31, 2010 (2009 – $81 million). However, the Terasen Gas 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 $63 million (December 31, 2009 – $81 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 $62 million for the year ended December 31, 2010 (2009 – $82 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $62 million (December 31, 2009 – $82 million).

The Corporation's exposure to market risk related to the foreign exchange forward contracts 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.

29. Commitments

(in millions)	Total	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Gas purchase contract obligations [(1)]	**$ 555**	$ 306	$ 195	$ 54	$ –
Power purchase obligations					
FortisBC [(2)]	**2,908**	44	89	81	2,694
FortisOntario [(3)]	**462**	47	97	101	217
Maritime Electric [(4)]	**245**	56	88	87	14
Belize Electricity [(5)]	**171**	18	37	42	74
Capital cost [(6)]	**446**	15	32	34	365
Operating lease obligations [(7)]	**134**	17	29	26	62
Joint-use asset and shared service agreements [(8)]	**65**	4	8	7	46
Defined benefit pension funding contributions [(9)]	**32**	14	13	2	3
Office lease – FortisBC [(10)]	**19**	2	3	3	11
Other [(11)]	**21**	5	9	6	1
Total	**$ 5,058**	$ 528	$ 600	$ 443	$ 3,487

(1) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas 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, 2010.

(2) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and the Powerex Corp. ("Powerex") capacity agreement. 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 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 2010 FortisBC entered into a capacity agreement with Powerex, a wholly owned subsidiary of BC Hydro, for fixed-price winter capacity purchases through to February 2016 in an aggregate amount of approximately US$16 million. If FortisBC brings any new resources, such as capital or contractual projects, online prior to the expiry of this agreement, FortisBC may terminate this contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex.

(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 electricity 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 capacity or energy. 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 the Point Lepreau and Dalhousie Generating Stations. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new international power line into the United States, and expires in November 2032.

(5) Power purchase obligations for Belize Electricity include a 15-year PPA, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity. In addition, two 15-year PPAs commenced in 2009 with Belize Cogeneration Energy Limited and Belize Aquaculture Limited to provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively.

(6) Maritime Electric has entitlement to approximately 6.7% and 4.7% of the output from the Dalhousie and Point Lepreau Generating Stations, respectively, for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of these units. The Company terminated the Dalhousie Generating Station agreement as of March 1, 2011.

(7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro.

29. Commitments (cont'd)

(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 2015 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, 2010 – Terasen (covering unionized employees) and FortisBC
December 31, 2011 – Newfoundland Power
December 31, 2012 – Terasen (covering non-unionized employees)

(10) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

(11) Other contractual obligations include capital lease obligations, operating building leases and AROs at FortisBC.

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 customer requests and by large capital projects specifically approved by their respective regulatory authority. The consolidated capital program of the Corporation, including non-regulated segments, is forecast to be approximately $1.2 billion for 2011, which has not been included in the commitments table above.

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments 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. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. 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 TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2009 and TGVI made a $4 million repayment on the loans during 2010 (2009 – $8 million). As at December 31, 2010, 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 TGVI 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. TGVI, however, estimates making payments under the loans of $24 million over 2012 and 2013, $20 million over 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, 2010, no such termination notice has been given by either party. As such, the contract is effectively renewed for 2011. The quantity of fuel to be purchased under the contract for 2011 is approximately 25 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.

30. 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.

Terasen

During 2007 and 2008, a non-regulated subsidiary of Terasen 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. Terasen has begun the appeal process associated with the assessments.

In 2009 Terasen 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. Terasen has filed a statement of defence but the claim is in its early stages. During the second quarter of 2010, Terasen 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

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by private landowners in relation to the same matter. FortisBC is communicating with its insurers and has filed a statement of defence in relation to both actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Exploits Partnership

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating plants 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.

31. Subsequent Event

On March 1, 2011 the Terasen Gas companies were renamed to commence operating under a common brand identity with FortisBC in British Columbia, Canada. As a result, the following name changes were made:

Names – Prior to March 1, 2011	Names – Effective March 1, 2011
Terasen Inc.	FortisBC Holdings Inc.
Terasen Gas Inc.	FortisBC Energy Inc.
Terasen Gas (Vancouver Island) Inc.	FortisBC Energy (Vancouver Island) Inc.
Terasen Gas (Whistler) Inc.	FortisBC Energy (Whistler) Inc.
Terasen Energy Services Inc.	FortisBC Alternative Energy Services Inc.

32. Comparative Figures

Certain comparative figures have been reclassified to comply with current period classifications. The most significant changes related to: (i) the Terasen Gas companies and Newfoundland Power, including a $2 million decrease in current regulatory assets, a $32 million decrease in long-term regulatory assets, a $6 million increase in utility capital assets, a $7 million increase in intangible assets, a $2 million decrease in current regulatory liabilities, a $13 million decrease in long-term regulatory liabilities and a $6 million decrease in long-term future income tax liabilities; and (ii) a $44 million increase in cash from operating activities associated with changes in non-cash operating working capital and a corresponding decrease in cash provided by financing activities associated with dividends on common shares.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2010**	2009 [(1)]	2008
Revenue, including equity income	**3,664**	3,643	3,907
Energy supply costs and operating expenses	**2,514**	2,578	2,859
Amortization	**410**	364	348
Finance charges	**350**	360	363
Corporate taxes	**67**	49	65
Results of discontinued operations, gains on sales and other unusual items	**–**	–	–
Net earnings	**323**	292	272
Net earnings attributable to non-controlling interests	**10**	12	13
Net earnings attributable to preference equity shareholders	**28**	18	14
Net earnings attributable to common equity shareholders	**285**	262	245
Balance Sheets *(in $ millions)*			
Current assets	**1,204**	1,124	1,150
Goodwill	**1,553**	1,560	1,575
Other long-term assets	**1,060**	917	487
Utility capital assets, income producing properties and intangible assets	**9,086**	8,538	7,954
Total assets	**12,903**	12,139	11,166
Current liabilities	**1,517**	1,592	1,697
Other long-term liabilities	**1,398**	1,288	727
Long-term debt and capital lease obligations (excluding current portion)	**5,609**	5,276	4,884
Preference shares (classified as debt)	**320**	320	320
Total liabilities	**8,844**	8,476	7,628
Shareholders' equity [(3)]	**4,059**	3,663	3,538
Cash Flows *(in $ millions)*			
Operating activities	**732**	681	661
Investing activities	**991**	1,045	852
Financing activities	**513**	592	387
Dividends, excluding dividends on preference shares classified as debt	**230**	205	191
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.79**	8.41	8.70
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease obligations (net of cash)	**58.4**	60.2	59.5
Preference shares (classified as debt and equity)	**9.0**	6.9	7.3
Common shareholders' equity	**32.6**	32.9	33.2
Interest Coverage *(x)*			
Debt	**2.0**	1.9	1.9
All fixed charges	**1.9**	1.8	1.8
Total Gross Capital Expenditures *(in $ millions)*	**1,073**	1,024	935
Common Share Data			
Book value per share (year end) *($)*	**18.92**	18.61	17.97
Average common shares outstanding *(in millions)*	**172.9**	170.2	157.4
Basic earnings per common share *($)*	**1.65**	1.54	1.56
Dividends declared per common share *($)*	**1.410**	0.780	1.010
Dividends paid per common share *($)*	**1.120**	1.040	1.000
Dividend payout ratio *(%)*	**67.9**	67.5	64.1
Price earnings ratio *(x)*	**20.6**	18.6	15.8
Share Trading Summary			
High price *($)* (TSX)	**34.54**	29.24	29.94
Low price *($)* (TSX)	**21.60**	21.52	20.70
Closing price *($)* (TSX)	**33.98**	28.68	24.59
Volume *(in thousands)*	**120,855**	121,162	132,108

(1) Certain 2009 comparative figures have been reclassified to comply with current period classifications. Refer to Notes 3 and 32 of the 2010 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 due to a change in presentation adopted by FortisBC effective December 31, 2009.

(3) Restated to include non-controlling interests upon adoption of CICA Handbook Section 1602, *Non-Controlling Interests*, effective January 1, 2010 per Note 3 to the 2010 Annual Consolidated Financial Statements.

Historical Financial Summary

2007	2006 (2)	2005 (2)	2004	2003	2002	2001
2,718	1,472	1,441	1,146	843	715	628
1,904	939	926	766	579	477	418
273	178	158	114	62	65	62
299	168	154	122	86	74	65
36	32	70	47	38	32	29
8	2	10	–	–	–	4
214	157	143	97	78	67	58
15	8	6	6	4	4	4
6	2	–	–	–	–	–
193	147	137	91	74	63	54
1,038	405	299	293	191	180	135
1,544	661	512	514	65	60	33
424	331	471	418	345	241	172
7,276	4,049	3,315	2,713	1,563	1,459	1,246
10,282	5,446	4,597	3,938	2,164	1,940	1,586
1,804	558	412	538	296	334	272
697	482	477	138	62	39	32
4,623	2,558	2,136	1,905	1,031	941	746
320	320	320	320	123	–	50
7,444	3,918	3,345	2,901	1,512	1,314	1,100
2,838	1,528	1,252	1,037	652	626	486
373	263	304	272	157	134	94
2,033	634	467	1,026	308	349	240
1,826	456	224	777	232	261	171
146	77	64	51	38	35	30
10.00	11.87	12.40	11.28	12.30	12.23	12.44
64.3	61.1	58.7	61.4	60.0	65.2	63.9
5.2	10.0	8.6	9.4	6.7	–	3.6
30.5	28.9	32.7	29.2	33.3	34.8	32.5
1.9	2.2	2.5	2.3	2.2	2.3	2.3
1.7	2.0	2.1	2.0	2.1	2.2	2.2
803	500	446	279	208	229	149
16.69	12.19	11.74	10.45	8.82	8.50	7.50
137.6	103.6	101.8	84.7	69.3	65.1	59.5
1.40	1.42	1.35	1.07	1.06	0.97	0.90
0.880	0.700	0.605	0.548	0.525	0.498	0.470
0.820	0.670	0.588	0.540	0.520	0.485	0.468
58.6	47.2	43.7	50.3	48.9	49.9	51.9
20.7	21.0	18.0	16.2	13.9	13.5	13.0
30.00	30.00	25.64	17.75	15.24	13.28	11.89
24.50	20.36	17.00	14.23	11.63	10.76	8.56
28.99	29.77	24.27	17.38	14.73	13.13	11.74
100,920	60,094	37,706	29,254	31,180	21,676	21,460

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 13, 2011	August 12, 2011
November 14, 2011	February 10, 2012

Dividend Payment Dates

June 1, 2011	September 1, 2011
December 1, 2011	March 1, 2012

Earnings Release Dates

May 4, 2011	August 3, 2011
November 3, 2011	February 9, 2012

* *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 obtain 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 6, 2011
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) 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

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F: 709.737.5307
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Investor Information

Fortis Inc. Officers

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President and Chief Executive Officer

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

Ronald W. McCabe
Vice President, General Counsel and Corporate Secretary

Donna G. Hynes
Assistant Secretary and Manager, Investor and Public Relations

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Chairman and CEO, Island Corporate Holdings
Nassau, Bahamas

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Corporate Director
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President and CEO, Provident Energy Ltd.
Calgary, Alberta

H. Stanley Marshall
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

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Corporate Director
Halifax, Nova Scotia

✻ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies please visit www.fortisinc.com.

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