Q. Please provide a copy of the annual reports of Fortis Inc. from 2009 to present.

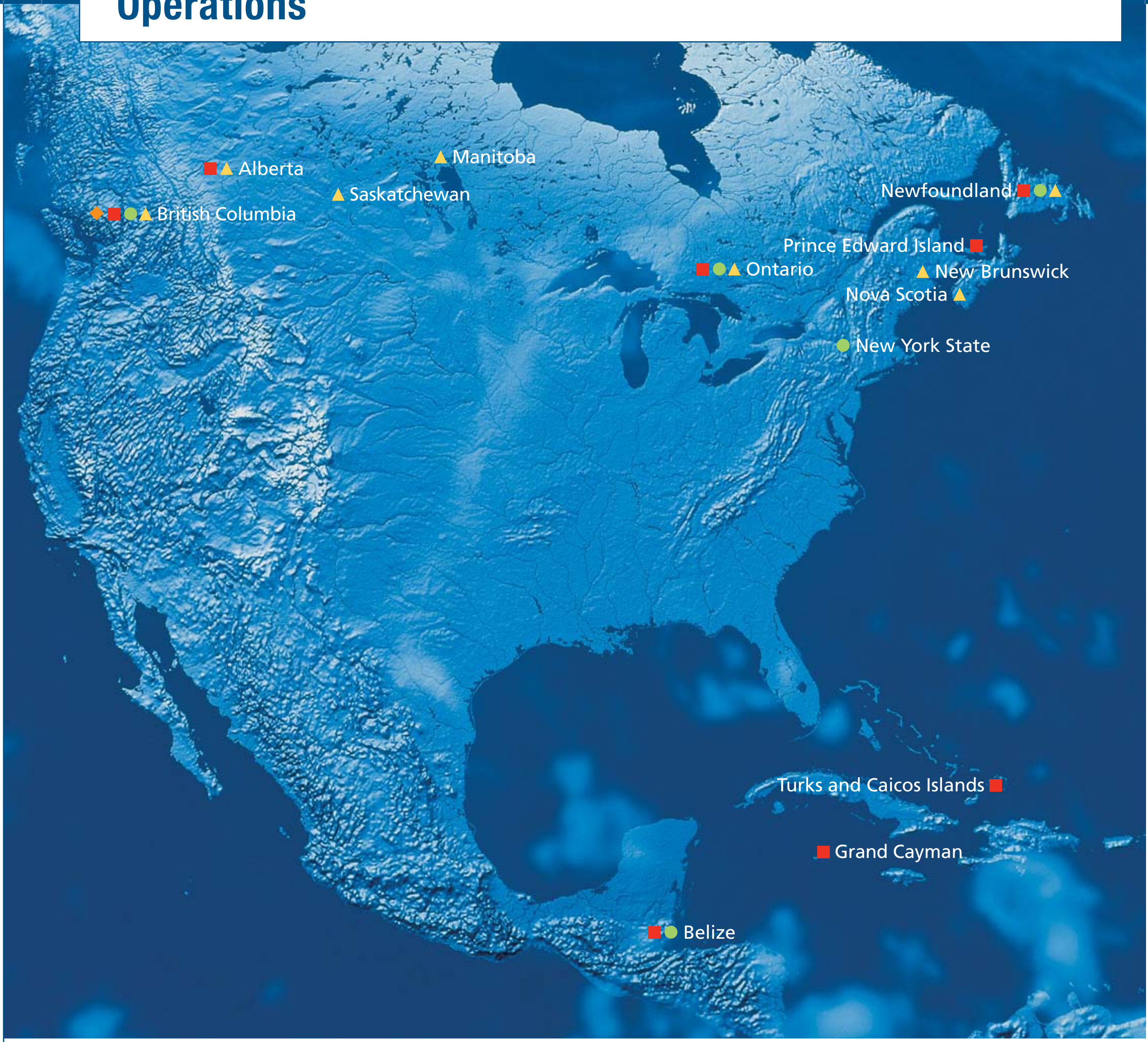
A. Attachment A provides a copy of the annual reports of Fortis Inc. from 2009 to present.

Annual Reports of Fortis Inc.
2009 to Present

FORTIS INC.

2009 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

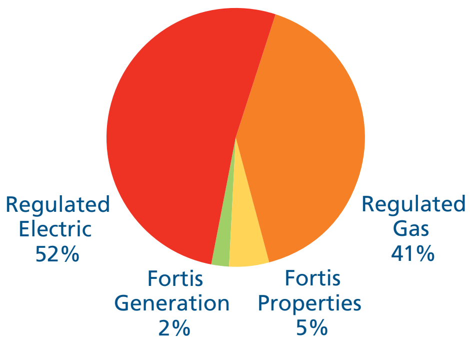
Production Areas
Belize, Ontario, Central Newfoundland, British Columbia, New York State

Fortis Properties

Real Estate and Hotels
Across Canada

Total Assets Exceed $12 Billion

(as at December 31, 2009)



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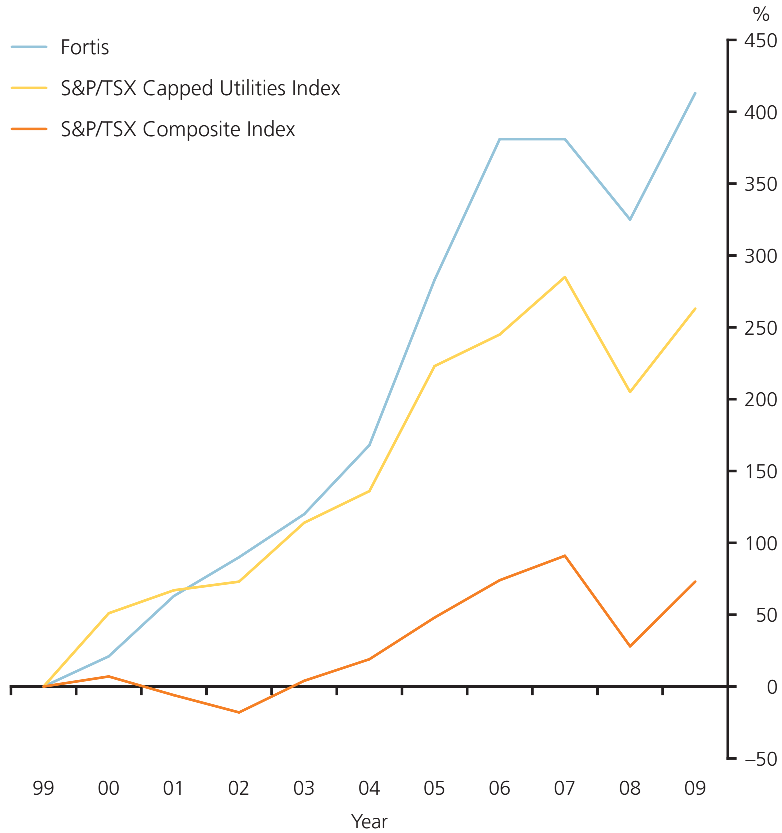
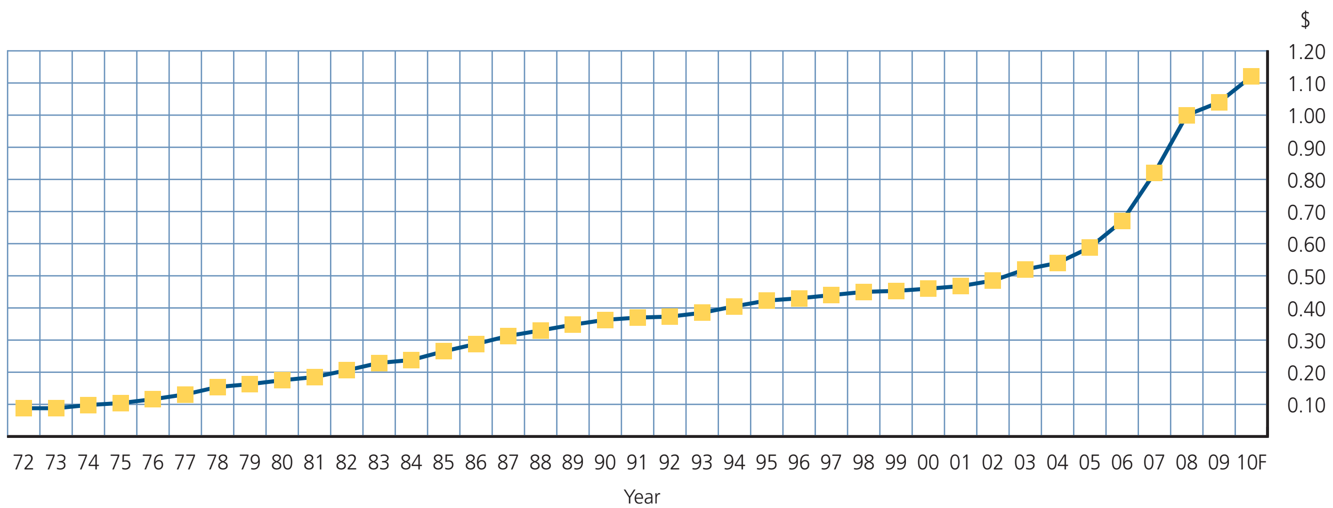
10-Year Cumulative Total Return



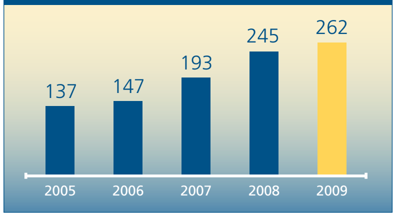
Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 37 consecutive years, the longest record of any public corporation in Canada.



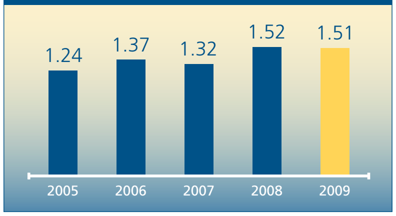
Investor Highlights

Earnings ($M)



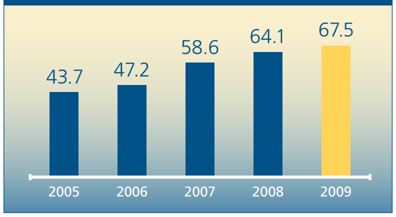
Basic Earnings per Common Share ($)

Diluted Earnings per Common Share ($)



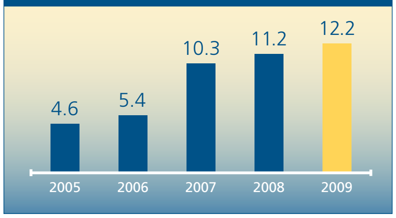
Dividends Paid per Common Share ($)

Dividend Payout Ratio (%)

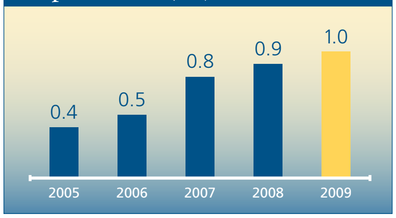


Return on Average Book Common Shareholders' Equity (%)

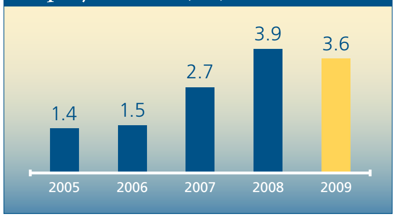
Assets ($B)



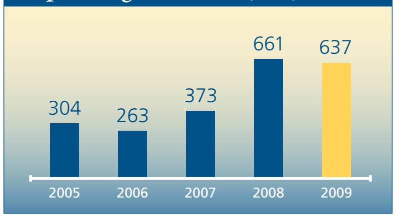
Capital Expenditures ($B)



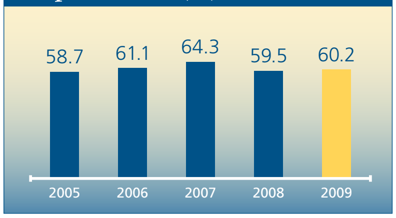
Revenue and Equity Income ($B)



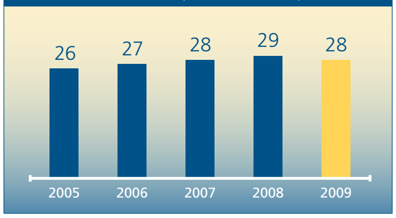
Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



Electricity Sales and Deliveries (000s GWh)



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2009 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] 2009	2010
Total	**940,000**	**1,295**	**1,234**	**207**	**246**	**5.0**	**3.1**	**117**	**9.50[4]**	**9.50**

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)[2]	Earnings ($M)	Allowed ROE (%)[3] 2009	2010
FortisAlberta	480,000	996	3,365	15,865	407	2.1	1.6	60	9.00	9.00
FortisBC	159,000	540	714	3,157	115	1.4	1.0	37	8.87	9.90
Newfoundland Power	239,000	568	1,219	5,299	74	1.2	0.9	32	8.95	9.00
Maritime Electric	74,000	179	219	1,032	30	0.4	0.3	11	9.75	9.75[5]
FortisOntario	64,000	184	265	1,163	16	0.2	0.2	9	8.01/8.57[6]	9.75[7]
Belize Electricity[8]	76,000	292	76	417	24	0.2	0.2	4	10.00[9]	[9][10]
Caribbean Utilities[11]	25,000	196	98	558	45	0.5	0.4	12	9.00–11.00[9]	7.75–9.75[9]
Fortis Turks and Caicos	9,000	105	30	165	23	0.2	0.1	11	17.50[9][12]	17.50[9]
Total	**1,126,000**	**3,060**	**5,986**	**27,656**	**734**	**6.2**	**4.7**	**176**		

(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 2010

(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. Effective July 1, 2009, ROE for Terasen Gas (Vancouver Island) Inc. is 50 basis points higher; prior to July 1, 2009, ROE was 70 basis points higher.

(4) Effective July 1, 2009; 8.47% prior to July 1, 2009

(5) Subject to regulatory approval

(6) Canadian Niagara Power 8.01%; Algoma Power 8.57%

(7) Subject to Canadian Niagara Power filing a full cost of service application in 2010

(8) 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 70.1% ownership interest.

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

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

(11) 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.

(12) 2009 achieved ROA 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**	**583**	**0.4**	**16**	**18**

Fortis Properties[2]

	Employees (#)	Assets ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	**2,300**	**0.6**	**24**	**26**

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, including the 19-MW Vaca hydroelectric generating facility in Belize, which will be commissioned in March 2010

(2) Includes approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada and 21 hotels across Canada

(3) Includes $130 million in "Other" non-regulated assets

(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2009

Information is for the fiscal year ended December 31, 2009 unless otherwise indicated.

Report to Shareholders

2009 was another successful year and marks a successful decade for your company.

For the 10th consecutive year, Fortis has delivered record earnings. Net earnings applicable to common shares were $262 million, $17 million higher than earnings of $245 million in 2008. Earnings per common share were $1.54 in 2009 compared to $1.56 in 2008. In 2000, your company earned $37 million and earnings per common share were $0.68.

Dividends paid per common share grew to $1.04 in 2009, up 4 per cent from $1.00 paid per common share in 2008. In 2000, dividends paid per common share were 46 cents, after giving effect to the 4-for-1 common share stock split that occurred in 2005. Fortis increased its quarterly common share dividend to 28 cents, commencing with the first quarter dividend paid in 2010. The 7.7 per cent increase in the quarterly common share dividend translates into an annualized dividend of $1.12 and extends the Corporation's record of annual common share dividend increases to 37 consecutive years, the longest record of any public corporation in Canada.

Stan Marshall, President and CEO, Fortis Inc. (left) and Geoffrey F. Hyland, Chair of the Board, Fortis Inc. (right).

Over the past 10 years, Fortis delivered an average annualized total return to shareholders of approximately 18 per cent, 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 approximately 14 per cent and 6 per cent, respectively, over the same period.

In the past two decades, Fortis has diversified beyond Newfoundland Power to become the largest investor-owned distribution utility in Canada, with regulated electric utility operations in five provinces across Canada and three Caribbean countries and regulated natural gas utility operations in British Columbia. Over the past decade, our customer base has grown from approximately 350,000 to 2,100,000; our common share market capitalization has increased from approximately $412 million to almost $5 billion; and our total assets have increased from approximately $1.2 billion to surpass $12 billion.

FortisAlberta's Automated Meter Infrastructure Project enables customers to better monitor and manage their energy consumption.

Fortis utilities continue to make the investments necessary to provide customers with safe, reliable energy at the lowest reasonable cost. Our capital program surpassed $1 billion in 2009, the largest annual capital program ever undertaken by Fortis. Approximately 75 per cent of this capital investment occurred at our regulated utilities in western Canada. Terasen Gas (Vancouver Island) made significant progress with the construction of its approximate $200 million liquefied natural gas storage facility, which is scheduled to come into service in 2011. FortisBC started construction of its $110 million Okanagan Transmission Reinforcement Project, the largest capital initiative ever undertaken by the utility. It is scheduled for completion by mid-2011. FortisAlberta continues work under its multi-year $155 million Automated Meter Infrastructure Project, with approximately 260,000 electronic meters installed at customer sites to date.

The US$53 million 19-megawatt ("MW") hydroelectric generating facility at Vaca in Belize will be commissioned in March 2010. No further investment in Belize is planned.

The global economic downturn and the busiest regulatory calendar in the history of Fortis made 2009 a challenging year. Strong performance from our regulated utilities in western Canada was tempered by the expiry in April of the 100-year water rights of the Rankine hydroelectric generating facility in Ontario and ongoing regulatory challenges in Belize.

A number of significant regulatory decisions received in the fourth quarter of 2009 should provide regulatory stability for 2010, enabling our utilities to focus on operations and meeting the energy needs of our customers.

Effective January 1, 2009, the allowed rate of return on common shareholder's equity ("ROE") at FortisAlberta increased to 9.00 per cent from an interim allowed ROE for 2009 of 8.51 per cent and the utility's equity component of total capital structure ("equity component") increased to 41 per cent from 37 per cent. Effective July 1, 2009, the allowed ROE at Terasen Gas Inc. increased to 9.50 per cent from 8.47 per cent. Effective January 1, 2010, the equity component of Terasen Gas increased to 40 per cent from 35 per cent. The Company also received regulatory approval of a negotiated settlement agreement for its 2010–2011 revenue requirements. A previous agreement had provided for the sharing of earnings above or below the allowed ROE with customers. The recently approved negotiated settlement agreement does not include an earnings sharing mechanism. At FortisBC, the allowed ROE increased to 9.90 per cent from 8.87 per cent, effective January 1, 2010. FortisBC also received regulatory approval of a negotiated settlement agreement for its 2010 revenue requirements. Newfoundland Power received regulatory approval for its 2010 revenue requirements and the Company's allowed ROE has been set at 9.00 per cent for 2010, up from 8.95 per cent for 2009.

The Terasen Gas (Vancouver Island) liquefied natural gas storage facility is scheduled to come into service in 2011.

The Terasen Gas companies delivered earnings of $117 million for 2009 compared to $118 million for 2008. Results for 2009 were constrained by increased costs of approximately $5 million after tax associated with the conversion of Whistler customer appliances from propane to natural gas. Regulatory approval is being sought to include the additional conversion costs in rate base. Results for 2008 were favourably impacted by an approximate $5.5 million tax reduction related to the settlement of historical corporate tax matters. Excluding these two items, earnings were $9.5 million higher year over year, mainly due to the impact of the higher allowed ROE, effective July 1, 2009, and lower effective corporate taxes.

The annual capital program of Fortis surpassed a record $1 billion in 2009.

Earnings at Canadian Regulated Electric Utilities were $149 million, up $23 million from $126 million for 2008. Excluding a one-time favourable $3 million corporate tax adjustment at FortisOntario in 2009 and a one-time $2 million charge at FortisOntario associated with the repayment of an interconnection agreement-related refund during 2008, earnings were $18 million higher year over year. Results were driven by the higher allowed ROE and increased equity component at FortisAlberta combined with rate base growth at FortisAlberta and FortisBC.

FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power Inc., in October for an aggregate purchase price of approximately $75 million. The utility serves approximately 12,000 customers in the District of Algoma in northern Ontario. The acquisition makes Fortis the only investor-owned electric distribution utility in Ontario.

Earnings at Caribbean Regulated Electric Utilities were $27 million compared to $17 million for 2008. Results for 2008 reflected a $13 million reduction in earnings related to a June 2008 regulatory decision at Belize Electricity but included $1.5 million of additional earnings from Caribbean Utilities related to a change in the utility's fiscal year end in 2008. Excluding these two items, earnings were $1.5 million lower year over year. The decrease was mainly due to the impact of a lower allowed rate of return on rate base assets at Belize Electricity for the entire year in 2009 compared to half a year in 2008 and higher operating costs. The decrease was partially offset by the favourable impact of a change in the methodology for calculating the cost of fuel recoverable from customers and a change in depreciation estimates at Fortis Turks and Caicos as well as the favourable impact of foreign currency translation. Results reflected slower electricity sales growth as a result of the negative impact of the global economic downturn. Annualized electricity sales growth was approximately 2 per cent for 2009 compared to 6 per cent for 2008.

Regulatory challenges are ongoing in Belize where Belize Electricity is legally contesting several decisions of its regulator. The Company's appeal of the June 2008 decision commenced in court in October 2009.

Earnings at Non-Regulated Fortis Generation were $16 million compared to $30 million for 2008. The decrease was mainly due to the lower contribution from the Rankine hydroelectric generating facility combined with lower average wholesale market energy prices and lower production in Upper New York State.

Earnings at Fortis Properties were $24 million compared to $23 million for 2008. Contributions from recently acquired hotels and the Real Estate Division and lower finance charges were partially offset by generally lower occupancies at the remainder of the Company's hotels as a result of the economic downturn.

Fortis and its four largest utilities have strong investment-grade credit ratings. In September, Standard & Poor's confirmed its credit rating for Fortis at A– (stable outlook), reflecting the diversity of the Corporation's regulated utility operations, the stability and predictability of the utilities' cash flows, and the Corporation's focused, well-executed growth strategy. Fortis is rated BBB (high) by DBRS.

Notwithstanding the severe global economic downturn and capital market volatility, Fortis and its utilities have raised approximately $1.3 billion in the capital markets since late 2008, demonstrating the financial strength of our core utility business. In December 2008, we completed a $300 million common share issue. In 2009, we issued more than $700 million of long-term debt, including 30-year $200 million 6.51% unsecured debentures at Fortis, 30-year $495 million long-term debt at rates ranging from 5.37% to 7.06% at our Canadian Regulated Utilities and 15-year US$40 million 7.50% long-term debt at Caribbean Utilities. In January 2010, Fortis issued $250 million five-year fixed rate reset preference shares with an initial annualized dividend of 4.25%.

Fortis, through its regulated and non-regulated businesses, owns and/or operates 1,840 MW of generation, mainly hydroelectric.

The Corporation's long-term debt maturities and repayments, as at December 31, 2009, are expected to average approximately $270 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to the debt and equity capital markets.

At December 31, 2009, Fortis had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.4 billion was unused, including $476 million unused under the Corporation's $600 million committed revolving credit facility. Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.


Over the next five years, capital expenditures are expected to approach $5 billion.

The commitment of Fortis employees, now almost 6,700 people strong, to deliver quality service to our customers continues to power our performance. Congratulations to each and every one of you on achieving another successful year. We welcome Messrs. Douglas Haughey and Ronald Munkley and Ms. Ida Goodreau who joined our Board this year. We extend our gratitude to each of our Board members for their guidance and support.

We continue to build boldly. Our 2010 capital program of more than $1 billion is well underway. Over the next five years, capital expenditures are expected to approach $5 billion, driven by ongoing investment in infrastructure at our regulated utilities in western Canada.

As a new decade begins to unfold, we are excited about the future growth prospects for your company. We will continue to build our business profitably through investment in our existing operations and the acquisition of regulated electric and natural gas utilities in the United States, Canada and the Caribbean.

On behalf of the Board of Directors,

Geoffrey F. Hyland
Chair of the Board
Fortis Inc.

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

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.

Terasen

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving approximately 940,000 customers or 96 per cent of gas users in the province. The Company delivers more than 20 per cent of the total energy consumed in British Columbia, comparable to the amount of electricity used in the province, making it a significant contributor to the province's energy mix.

Terasen's regulated natural gas and piped-propane transmission and distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the Terasen Gas companies. Its operations also include Terasen Energy Services, which finances, designs, owns and operates geoexchange systems, community piping and energy-transfer systems to harness renewable energy sources.

Officers of Terasen (l-r): Jan Marston, VP, HR and Operations Governance; Dwain Bell, VP, Distribution; Cynthia Des Brisay, VP, Gas Supply and Transmission; Bob Samels, VP, Business Services and Technology; Randy Jespersen, President and CEO; Roger Dall'Antonia, VP, Corporate Development and Treasurer; David Bennett, VP and General Counsel; Scott Thomson, VP, Regulatory Affairs and CFO; Doug Stout, VP, Marketing and Business Development

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 839,000 customers. Its service territory 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. The Company serves approximately 98,000 customers. TGWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), providing service to approximately 2,600 customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines. In 2009, gas volumes were 207,230 terajoules ("TJ") and a peak day demand of 1,234 TJ was met.

Terasen achieved a record Customer Satisfaction Rating of 80 per cent in 2009. Residential customers gave improved ratings for emergency and non-emergency services, as well as marketing and communication initiatives.

The approximate $27 million Fraser River South Bank South Arm Rehabilitation Project is expected to be in service by the end of August 2010.

The Terasen Gas companies invested approximately $246 million, before customer contributions, in capital programs in 2009 to ensure the safe, reliable delivery of piped energy to customers.

Construction continued on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island. When it comes into service, expected in 2011, the facility will allow for more efficient use of existing pipeline systems and improve reliability and security of supply during periods of system interruptions or increased energy demand. Construction of the 50-kilometre natural gas pipeline from Squamish to Whistler and conversion of Whistler to natural gas from propane was completed in 2009 at a total project cost of $56 million. More than 14,000 appliances were converted to natural gas, which will result in a 15 per cent reduction in annual greenhouse gas ("GHG") emissions by natural gas customers and a 5 per cent reduction in annual GHG emissions by the region. An approximate $27 million pipeline upgrade below the south arm of the Fraser River to maintain the integrity of these infrastructure assets is expected to be completed by the end of August 2010.

Terasen continued work on the Village of Fraser Mills district energy system in Coquitlam, the Beedie Group's largest sustainable development project. The district energy system could potentially displace up to 8,200 tonnes of GHG emissions annually–the equivalent of removing 2,500 cars from the road.

FortisAlberta

FortisAlberta is an electric utility that distributes electricity generated by other market participants to end-use customers in southern and central Alberta. Its electricity system includes approximately 110,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 480,000 customers and met a record peak demand of 3,365 MW in 2009.

Officers of FortisAlberta (l-r): Alan Skiffington, VP, Business Services and CIO; Nipa Chakravarti, VP, Customer Service; Ian Lorimer, VP, Finance and CFO; Karl Smith, President and CEO; Phonse Delaney, VP, Operations and Engineering; Annette Butt, VP, Human Resources and Corporate Communications

A Customer Satisfaction Rating of 83 per cent was achieved in 2009 compared to an average annual rating of 80 per cent for the previous three years. Customer Contact Centre staff handled approximately 194,000 calls in 2009. Employees resolved 87 per cent of customer concerns during the initial contact.

A record $407 million, before customer contributions, was invested in capital projects in 2009 to maintain the system, install automated meters and meet customer growth. More than 10,000 new customers were connected to the utility's distribution system, including several large and complex business operations such as the CrossIron Mills shopping mall near Balzac and TransCanada's Keystone Pipeline in Hardisty. Approximately 3,000 kilometres of power lines were added to the distribution system. Construction of new farm irrigation services and business activity in Alberta continued to drive the need for additional distribution lines. FortisAlberta worked closely with the transmission service provider and the Alberta Electric System Operator to increase substation capacity, improve reliability and meet customer load growth in Devon, Fort Saskatchewan, Manyberries, Hayter, Fort Assiniboine and Hardisty.

The Company's multi-year Automated Meter Infrastructure ("AMI") Project, estimated at a total capital cost of $155 million, involves the scheduled replacement of 466,000 conventional meters at customer sites with AMI technology by the end of 2011. Approximately 260,000 electronic meters have been installed to date. AMI technology, which replaces the manual and estimated meter reading system, will help reduce operating costs and enable customers to better monitor and manage their energy consumption. By eliminating the need for manual meter readings, carbon dioxide emissions from utility vehicles will be reduced by more than 1,000 metric tonnes annually.

The Government of Alberta implemented regulation in 2009 to assist Albertans in generating electricity from renewable sources to power their homes, farms and businesses. During the year, FortisAlberta connected 60 wind and solar power customers to its distribution system, enabling them to obtain electricity when needed and receive credit from their respective retailers for renewable-source energy supplied to the province's electricity grid. FortisAlberta ensures these interconnections are safe and do not affect power quality or reliability for other customers.

A record $407 million, before customer contributions, was invested in capital projects in 2009 to maintain the system, install automated meters and meet customer growth.

For the second consecutive year, employees received the Government of Alberta's *Best Safety Performer Award*, ranking FortisAlberta in the 99.5th percentile of employers in the province. Safety initiatives helped achieve a record low Lost-Time Injury Severity Rate in 2009. Safe-work practices resulted in seven offices celebrating a minimum of nine years without a lost-time injury.

Electrical contacts with FortisAlberta distribution lines continue to be a concern. The Company participates in the *Where's the Line?* campaign, an industry and government partnership focused on public education regarding electrical safety. Employees delivered more than 100 electrical safety presentations to high-risk external companies, emergency personnel and relevant industry associations, focusing on safe-work planning, effective response to electrical incidents and the dangers of high-voltage work.

Through its Environmental Management System, which is consistent with the international ISO 14001 standard, programs have been established to improve environmental performance. More than 600 employees received job-specific environmental training in 2009.

FortisBC

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving approximately 159,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution power lines and four regulated hydroelectric generating plants on the Kootenay River with a combined capacity of 223 MW. The annual gross energy entitlement from the plants is approximately 1,591 gigawatt hours ("GWh"). The Company also manages 947 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements with the balance met through power purchase agreements. The utility met a peak demand of 714 MW in 2009. A record summer peak demand of 406 MW was met in 2009, exceeding the previous record of 387 MW reached in 2007.

Officers of FortisBC (l-r): David Bennett, VP, Regulatory Affairs, General Counsel and Corporate Secretary; Doyle Sam, VP, Engineering and Operations; John Walker, President and CEO; Michele Leeners, VP, Finance and CFO; Michael Mulcahy, VP, Customer and Corporate Services; Don Debienne, VP, Power Supply and Strategic Planning

A Customer Satisfaction Rating of 86 per cent was achieved in 2009, consistent with the rating in 2008. Results in all customer service areas were strong, despite the impact of a significant winter storm which affected more than 18,000 customers in the Kootenay area. Overcoming the challenges of severe weather conditions and road closures, employees restored service to all affected customers within 24 hours.

FortisBC invested approximately $115 million, before customer contributions, in capital projects in 2009 to meet growing energy demand and replace aging infrastructure. Construction of the $15 million Black Mountain substation and associated distribution line was completed, servicing growth to areas in northeast Kelowna. A new substation in north Kelowna, the final phase of the $17 million Ellison project, and the $7 million Naramata substation project were commissioned. Work also began on the $18 million Benvoulin substation project to meet growing customer demand in central Kelowna.

The $110 million Okanagan Transmission Reinforcement Project is the largest capital project ever undertaken by FortisBC.

Construction started on the $110 million Okanagan Transmission Reinforcement Project, the largest capital project ever undertaken by FortisBC. Upgrades to existing transmission lines and substations and the building of a new 230-kilovolt ("kV") distribution line and substation are scheduled for completion by mid-2011.

Approximately $13 million was invested in the ongoing hydroelectric generation Upgrade and Life Extension Program in 2009, which involves rebuilding 11 of the 15 hydroelectric generating units in the utility's four generating plants. Eight units have been rebuilt to date and the program is scheduled for completion in 2012. The upgrades will improve efficiency, safety and environmental stewardship and will maintain the overall reliability of the plants.

In September, FortisBC received regulatory approval for its Net Metering Program, which enables customers to offset part or all of their electricity requirements by generating electricity from renewable sources, such as wind, hydro or solar. Customers receive a billing credit for any renewable-source energy they provide to the Company's electricity grid.

A proactive consultation program continues with the public, stakeholders and First Nations in regard to capital programs, focusing on creating meaningful opportunities for open dialogue, information sharing and long-term cooperative relationships. FortisBC received the *2009 Industry Partner Award* at the British Columbia Aboriginal Tourism Awards ceremony.

Celebrating its 20th anniversary in 2009, the Company's *PowerSense Program* offers customers financial incentives and advice on energy-efficient technologies and practices. Since 1989, customers have achieved total energy savings of 360 GWh–the equivalent of the energy used by almost 28,000 homes for a full year.

Newfoundland Power

Officers of Newfoundland Power (l-r): Jocelyn Perry, VP, Finance and CFO; Peter Alteen, VP, Regulation and Planning; Gary Smith, VP, Customer Operations and Engineering; Earl Ludlow, President and CEO

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves more than 239,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 30 small generating stations with an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,219 MW in 2009. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro ("Newfoundland Hydro").

A Customer Satisfaction Rating of 90 per cent was achieved in 2009, slightly higher than the rating for the previous year. Newfoundland Power launched four new energy rebate programs for residential and commercial customers under its *takeCHARGE–Saving Energy Starts Here!* partnership with Newfoundland Hydro. Almost 2,000 customers availed of the new rebate programs, which were promoted through media, trade shows, municipal seminars and point-of-purchase information at building supply stores. The *takeCHARGE* Energy Savers Rebate Programs and similar initiatives will help customers conserve 15 GWh of energy annually by 2013–equivalent to the energy needs of 1,400 homes heated with electricity.

Almost $74 million, before customer contributions, was invested in capital projects in 2009 to upgrade and modernize the utility's electricity system. More than 30 per cent of this investment was allocated to connect a record annual addition of 5,000 new customers. A $4.5 million upgrade of transmission lines, including two transmission lines on the Bonavista Peninsula, was completed. The penstock at the Rocky Pond hydroelectric plant was replaced at a total cost of approximately $5.2 million and a $4.5 million refurbishment and upgrade of several substations across the province was completed. 2009 was a record year for the lowest number and shortest duration of power outages.

As part of its Five-Year Capital Plan, the Company is increasing the efficiency of its hydroelectric plants, which will reduce its need for energy from Newfoundland Hydro's Holyrood Generating Plant. More than $0.5 million was invested to raise the spillway and increase the amount of energy output at the Rose Blanche hydroelectric plant. Almost 1,400 streetlights across the province were replaced with energy-efficient high-pressure sodium lights, which consume 35 per cent less energy and maintain the same quality of light as traditional streetlights.

2009 was the best year on record for safety performance, with the Company reporting its lowest number of safety injuries in more than 40 years. Safety performance was driven by refocused employee commitment to safety supported by several initiatives, including the launch of a new internal safety program. A new television advertisement promoted public awareness of electrical hazards. A direct mail campaign to contractors was completed as a reminder about safety requirements when working around electrical equipment. Newfoundland Power continued to partner with Newfoundland and Labrador Crime Stoppers to prevent incidents of vandalism and convey the safety risks associated with damaged electrical equipment.


Almost $74 million, before customer contributions, was invested in capital projects in 2009 to upgrade and modernize the utility's electricity system.

An external audit of the Environmental Management System verified continued compliance with the international ISO 14001 standard and confirmed the Company's commitment to carrying out its operations in an environmentally responsible manner. 2009 marked the 12th anniversary of Newfoundland Power's *EnviroFest Program* which, to date, has entailed the planting of almost 2,000 trees to improve the environment and beautify green spaces throughout the province.

Maritime Electric

Maritime Electric, the principal electric utility on Prince Edward Island (the "Island"), serves approximately 74,000 customers or 90 per cent of electricity consumers in the province. The Company owns and operates a fully integrated system, comprised of approximately 5,300 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity throughout the Island. Maritime Electric maintains on-Island generating facilities with a combined total capacity of 150 MW at Charlottetown and Borden-Carleton. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait. The utility met a peak demand of 219 MW in 2009.

Officers of Maritime Electric (l-r): Steve Loggie, VP, Customer Service; John Gaudet, VP, Corporate Planning and Energy Supply; Bill Geldert, VP, Finance & Administration, CFO and Corporate Secretary; Fred O'Brien, President and CEO

Maritime Electric purchases approximately 86 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). Purchases are made through a short-term energy purchase agreement with NB Power and entitlements from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and Dalhousie Generating Station through agreements that extend for the life of these stations. A refurbishment of Point Lepreau began in April 2008, which will extend its life by 25 years and provide additional stability with respect to long-term energy supply. The station is scheduled to return to service in early 2011.

The balance of the Company's energy requirements is obtained from on-Island wind-powered generation facilities and from the utility's own generating plants. Approximately 14 per cent of total energy supply was derived from wind-powered generation in 2009.

While challenged with increasing energy costs to meet the Island's energy demand, Maritime Electric achieved a Customer Satisfaction Rating of 75 per cent in 2009. To enhance customer service, the Company's website was redesigned with energy-efficient interactive and educational tools such as the *Virtual Home, Energy Calculator* and *100 Ways to Save on Your Electricity Bill*.

Approximately $30 million, before customer contributions, was invested in capital projects in 2009 to improve system reliability and customer service. Construction was completed on the 71-kilometre 138-kV transmission line and power corridor in western Prince Edward Island, which will deliver wind-powered energy to the North American grid. The $16 million project, jointly funded by the Government of Prince Edward Island and SUEZ Energy North America, will facilitate further expansion of wind-powered generation on the Island.

Maritime Electric's goal is that 30 per cent of its annual energy sales be sourced from renewable energy supply by 2013. Work continues with the Government of Prince Edward Island and PEI Energy Corporation on the development of additional generation from renewable sources. In October, Maritime Electric issued a request for proposal seeking 30 MW of energy from renewable resources. The Company is also supporting the development of an additional 100 MW from wind-powered sources that will help the province of Prince Edward Island in its efforts to capitalize on the Island's wind resource and meet its target of 500 MW of wind-powered generation on the Island by 2013.

Maritime Electric serves approximately 74,000 customers on Prince Edward Island.

In order to facilitate the export of merchant wind-generated electricity, Maritime Electric is working with the province of Prince Edward Island to secure the necessary funding for the installation of a 200-MW interconnection with the mainland via a cable in the Confederation Bridge.

Through its *Demand Side Management and Energy Conservation Program*, an energy audit was undertaken of 15 businesses with the results used to provide energy conservation information to interested parties through a series of town hall meetings. The *Winter Challenge Program* challenged residential customers to reduce their energy consumption by 10 per cent in December 2009 from December 2008. More than 4,600 customers met the challenge.

FortisOntario

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power, Cornwall Electric and Algoma Power, serving approximately 64,000 customers mainly located in Fort Erie, Port Colborne, Cornwall, Gananoque and the District of Algoma in Ontario. Its regulated assets include approximately 3,300 kilometres of distribution and transmission lines in the Niagara and Cornwall regions and the District of Algoma, including an international interconnection between New York State and Fort Erie. FortisOntario owns a 10 per cent strategic interest in Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec. A combined peak demand of 265 MW was met in 2009.

Officers of FortisOntario (l-r): William Daley, President and CEO; Glen King, VP, Finance and CFO; Angus Orford, VP, Operations; Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary

In October, FortisOntario acquired Algoma Power (formerly known as Great Lakes Power Distribution Inc.), which serves approximately 12,000 customers in the District of Algoma in northern Ontario. Its assets include more than 1,800 kilometres of distribution lines in an area that covers approximately 14,200 square kilometres, which is more than double the size of the Greater Toronto Area.

A record overall Customer Satisfaction Rating of 88 per cent was achieved in 2009 compared to 84 per cent in the previous year. Customers rated the utility's reliability/safe delivery of electricity and quality of service at 94 per cent and 91 per cent, respectively. The Company continues to exceed the performance standards set by the Ontario Energy Board with respect to response times, service connections and call response statistics.

Capital investments totalled approximately $16 million, before customer contributions, in 2009, including new service connections and system rebuild projects to enhance the safety and reliability of the distribution system. In Niagara, construction was completed on a new $2.1 million substation to support load growth and replace an existing substation near the end of its useful life. Feeder upgrades were completed to increase system capacity for normal supply and emergency support, and work continued on voltage conversions. In Gananoque, construction continued on the rebuilding of the 26.4-kV feeders and replacement of distribution equipment nearing the end of its useful life. In Cornwall, capital projects focused on new customer connections, rebuilding a 3.5-kilometre rural feeder to support industrial and residential load growth and constructing a 4-kilometre feeder to supply load-transfer customers formerly supplied by Hydro One.

A record overall Customer Satisfaction Rating of 88 per cent was achieved in 2009.

The Government of Ontario has mandated all regulated electric utilities in the province to install smart meters, which track time-of-use consumption data, at customer sites by the end of 2010. During 2009, FortisOntario completed 90 per cent of smart meter installations in Fort Erie and began installations in Port Colborne. Smart meter installations in the Gananoque and Algoma territories will begin spring 2010. Time-of-use rates are anticipated to be implemented by spring 2011.

FortisOntario is implementing an integrated health, safety and environmental management system. Its utilities received Merit Certificates from the Electrical and Utilities Safety Association of Ontario in recognition of achieving zero lost-time injuries. A follow-up waste audit in 2009 verified 93 per cent of office waste was being diverted from landfill.

Belize Electricity

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 76,000 customers, the utility met a peak demand of 76 MW in 2009 from multiple sources of energy, including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE") (the Mexican state-owned power company), Belize Cogeneration Energy Limited ("BELCOGEN"), Hydro Maya Limited and Belize Aquaculture Limited, and from its own diesel-powered and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 34 MW and owns more than 2,900 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Officers of Belize Electricity (l-r): Rene Blanco, VP, Finance & Administration and CFO; Lynn Young, President and CEO; Curtis Eck, VP, Customer Care and Operations; Joseph Sukhnandan, VP, Engineering and Energy Supply; Juliet Estell, Manager, Executive Services and Company Secretary

Despite the significant ongoing operational constraints imposed as a result of regulatory decisions received in 2008, which are being challenged in the Supreme Court of Belize, Belize Electricity earned a Customer Satisfaction Rating of approximately 82 per cent in 2009.

Approximately $24 million, before customer contributions, was invested in capital programs in 2009. Almost 68 kilometres of distribution lines were built to meet growth in customer demand and improve the quality of service delivery. Approximately 18 kilometres of distribution lines, including a 1.6-kilometre submarine cable, were constructed to enhance reliability of service to customers, including major tourism and real estate developments, on the island of San Pedro.

Belize Electricity proceeded with the US$2.3 million Banana Belt Electrification Project to connect seven rural communities in southern Belize to the national electricity grid. Funding for this project is being provided by the European Union and the Government of Belize. Approximately 80 kilometres of distribution lines are being constructed to deliver electricity service for the first time to almost 5,000 residents. Two of the seven communities have been connected to the national electricity grid with the remainder to be connected by mid-2010.

Approximately US$2 million was invested in 2009 to build new substations and associated transmission lines to connect Belize Aquaculture Limited, BELCOGEN and BECOL's Vaca hydroelectric generating facility. These new generation facilities will collectively supply up to 48 MW of capacity to the national electricity grid, bringing total in-country generation capacity to 117 MW.

CFE cancelled its Power Purchase Agreement ("PPA") with Belize Electricity in October, citing force majeure reasons. CFE advised that the cancellation of the PPA, which was to expire in December 2010, had become necessary as a result of limited generation capacity. CFE continues to supply Belize Electricity with power when available. With in-country generation capacity well above the country's peak demand, Belize Electricity is only purchasing power from Mexico when it is more economical than in-country generation.

Approximately $24 million, before customer contributions, was invested in capital projects in 2009.

Belize Electricity continues to strengthen its Environmental Management System by ensuring it meets and exceeds all related legal requirements. Key areas of focus in 2009 were spill prevention and response. The transportation of fuel over open waters to Caye Caulker for generation purposes was made safer by using a barge specifically designed to carry petroleum products and equipped with safety features to minimize the risk of spills. Environmental training was undertaken with employees and contractors.

Employee development continues to be a priority. Hotline techniques training was completed, enabling crews to carry out maintenance on energized power lines, which helps improve service reliability. Line crews were also trained to conduct line inspections and thermoscanning surveys to quickly identify and address trouble spots on the electricity system. Under a four-year Apprenticeship Training Program, modelled after FortisAlberta's program, 30 line staff are working to become certified journeymen.

Caribbean Utilities

Caribbean Utilities generates, transmits and distributes electricity to more than 25,000 customers on Grand Cayman, Cayman Islands. The utility owns and operates approximately 555 kilometres of transmission and distribution lines and 24 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 153 MW. The Company met a record peak demand of 97.5 MW in 2009.

Officers of Caribbean Utilities (l-r): David Watler, VP, Production; Richard Hew, President and CEO; Letitia Lawrence, VP, Finance and CFO; Douglas Murray, Corporate Secretary; Andrew Small, VP, Transmission and Distribution

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis has an approximate 59 per cent controlling ownership interest in the utility.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region. The Company achieved a Customer Satisfaction Rating of 84 per cent in 2009 compared to 87 per cent in 2008. The slightly lower rating was attributable to the customer impact of increased fuel prices. Caribbean Utilities posted an Average Service Availability Index of 99.95 per cent in 2009.

Capital investments totalled approximately $45 million in 2009. Projects undertaken included completion of the building expansion and installation of a 16-MW diesel-powered generating unit and associated equipment for a total project cost of approximately US$30 million, the US$8 million expansion and upgrade to the transmission and distribution system and the US$1 million upgrade to the North Sound substation. Under a strategic alliance relationship over the past ten years with MAN Diesel SE, Caribbean Utilities has acquired five diesel-powered generating units, bringing total installed MAN Diesel SE supplied generation to approximately 69 MW.

Caribbean Utilities completed the installation of more than 200 concrete poles, weighing almost 10,000 pounds each, associated with its 69-kV transmission loop along the Frank Sound Road. The poles, which are designed to better sustain the potential impact of a hurricane, will enhance reliability of electricity service and help meet growth in energy demand.

Caribbean Utilities continues to explore energy supply options from renewable sources such as solar (photovoltaic) or wind. The *Consumer Owned Renewable Energy Program*, a joint initiative between the Company and the ERA, provides a mechanism for customers on Grand Cayman who generate their own energy from renewable sources to remain connected to the utility's transmission and distribution system. Caribbean Utilities is reviewing two proposals received in response to its expressions of interest for up to 10 MW of wind-powered generation.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region.

Caribbean Utilities hosted the Caribbean Electric Utility Service Corporation ("CARILEC") CEOs conference in June. CARILEC is an association of 33 electric utilities, suppliers, manufacturers and other stakeholders operating in the electricity industry in the Caribbean. It plays a coordinating role in servicing its members' needs for training, research, information sharing and mutual aid in disaster recovery.

Caribbean Utilities continues to demonstrate its environmental commitment through its ISO 14001:2004 registered Environmental Management System associated with its generation operations. A *Scrap Metal Recycling Program* was implemented to centrally collect scrap metal and ship overseas for recycling. Under its *Energy Smart Program*, which promotes energy conservation, the Company has been conducting complimentary energy smart audits for customers for seven years.

Fortis Turks and Caicos

Fortis Turks and Caicos is a fully integrated electric utility providing for the generation, transmission and distribution of electricity on Providenciales, North Caicos, Middle Caicos and South Caicos and the supply of electricity on Dellis Cay in the Turks and Caicos Islands. Fortis Turks and Caicos serves more than 9,000 customers or 85 per cent of electricity consumers in the Turks and Caicos Islands. Its regulated assets include 235 kilometres of transmission and distribution lines. The utility has a combined diesel-powered generating capacity of 54 MW and met a combined record peak demand of 29.6 MW in 2009.

An overall Customer Satisfaction Rating of 95 per cent was achieved in 2009 compared to 79 per cent in 2008. The improved rating was attributable to the Company's performance in restoring service following a tropical storm and Category 4 hurricane in September 2008, enhanced system reliability and the introduction of new customer services, such as the launch of the utility's website, electronic billing (eBills) and Internet bill payment options.

Officers of Fortis Turks and Caicos (l-r): Ruth Gardiner-Forbes, VP, Finance and CFO; Brian Walsh, VP, Operations; Eddinton Powell, President and CEO; Allan Robinson, VP, Customer and Corporate Services; Ernest Jackson, VP, Production and Engineering

Capital investments totalled approximately $23 million, before customer contributions, in 2009. Construction of the US$2 million central warehouse and US$0.9 million vehicle maintenance centre was completed which, together with the re-engineering of the utility's purchase order and inventory systems, have significantly improved material management procedures. Several information technology ("IT") infrastructure projects were completed to improve internal communications and reporting capabilities, including the new US$0.4 million IT Disaster Recovery Centre, the installation of an exchange server, completion of a network upgrade and the installation of fibre-optic links between corporate offices, the central warehouse, the IT Disaster Recovery Centre and the generation plant building.

Two Caterpillar 3612 series units were commissioned in May at a total cost of US$8.3 million, increasing the utility's installed generating capacity by 6.6 MW. A purchase agreement was signed with Wärtsilä Finland OY in June for two diesel-powered generating units with a combined capacity of approximately 18 MW. The units are scheduled for delivery mid-2010 and early 2011.

The US$0.5 million Bellamy Re-engineering Project was launched in January, an initiative to streamline internal operating procedures and upgrade the utility's financial reporting system to improve overall operational effectiveness, and enable the implementation of a fixed-asset management system.

Significant progress was made in the development of the Company's Environmental Management System in 2009. The US$0.6 million refurbishment and noise-attenuation work to the Engine Room South Building was completed, drastically reducing noise levels at the plant. All exhaust stacks were increased in height to achieve optimum plume dispersion as recommended in the Company's environmental audit. Construction began on the first phase of the ground water management systems, which will control heavy rainfall runoff from buildings.

Employee development is a major priority for Fortis Turks and Caicos. During the year, the Company offered IT, credit-control and line-staff apprenticeship training, and provided opportunities for employees to gain exposure to similar operations across the Fortis Group. With the introduction of its scholarship program, the Company granted three engineering scholarships and one accounting scholarship.

An overall Customer Satisfaction Rating of 95 per cent was achieved in 2009.

Fortis Generation

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State with a combined generating capacity of 139 MW, 134 MW of which is hydroelectric generation.

BECOL owns and operates the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 19-MW Vaca hydroelectric generating facilities located on the Macal River, the largest such facilities in Belize, Central America. Energy production was higher than the projected average at 180 GWh in 2009 compared to 192 GWh in 2008, when annual energy production hit a record high due to above-average rainfall. The Belize Meteorological Office confirmed that the flood-control features of the Chalillo facility significantly reduced the impact on downstream communities of widespread flooding related to heavy rainfall in July.

The US$53 million Vaca facility will be commissioned in March 2010. The run-of-river hydroelectric facility, which is situated approximately five kilometres downstream from Mollejon, is the final phase of the three-phase hydroelectric development plan for the Macal River. BECOL sells its entire output to Belize Electricity under 50-year power purchase agreements.

Fortis Generation has a combined generating capacity of 139 MW, 134 MW of which is hydroelectric generation.

In Ontario, non-regulated operations include 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 electricity produced from these facilities is sold in Ontario at market prices, with the exception of the cogeneration plant in Cornwall. The 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls expired in April at the end of a 100-year term.

The Exploits River Hydro Partnership ("Exploits Partnership") is owned 51 per cent by Fortis Generation and 49 per cent by AbitibiBowater Inc. ("Abitibi"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi's two hydroelectric generating plants in central Newfoundland. In December 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of Abitibi's assets in Newfoundland, including those assets associated with the generation of electricity, some of which included the capital assets of the Exploits Partnership. 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 US$53 million 19-MW Vaca hydroelectric generating facility on the Macal River in Belize will be commissioned in March 2010.

In British Columbia, the non-regulated generating asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC. The plant sells its entire output to BC Hydro under a long-term contract.

In Upper New York State, the non-regulated generating assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined capacity of approximately 23 MW. The average annual 85 GWh of energy output of these modern facilities is sold at the wholesale level through a number of renewable contracts.

Fortis Properties

Fortis Properties owns and operates 21 hotels, offering more than 4,100 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada.

The Hospitality Division was significantly challenged in 2009 by the global economic downturn. Revenue per available room ("RevPAR") decreased by 4.8 per cent to $76.55 from the previous year, primarily as a result of decreased occupancy. An aggressive cost-management strategy was implemented to mitigate revenue pressures resulting from the economic downturn. National RevPAR declined 12.3 per cent for 2009 compared to the previous year.

Fortis Properties acquired the 214-room Holiday Inn Select Windsor in Ontario for $7 million in April. The hotel offers standard, suite and executive rooms and has more than 14,000 square feet of meeting and banquet space. A four-year $4.1 million capital investment began in 2009 to complete interior renovations, including the installation of a fire-sprinkler system, and exterior upgrades.

Officers of Fortis Properties: Nora Duke, President and CEO; Jamie Roberts, VP, Finance and CFO; Terry Chaffey, VP, Real Estate

Approximately $3.2 million was invested in lobby and room renovations at the Sheraton Hotel Newfoundland. The hotel's extensive capital improvement plan will continue through to 2011 with upgrades to guest rooms, food and beverage outlets and meeting space.

The 70-room expansion of the Holiday Inn Express Kelowna opened in February 2010. The new tower includes executive rooms, business and family suites, two indoor waterslides and approximately 4,500 square feet of meeting space.

The Real Estate Division continued to exhibit stable performance, supported by a focus on quality customer service and long-term leases with quality tenants. The year-end occupancy rate was 96.2 per cent, outpacing the national rate of 90.2 per cent. Most of the Company's major real estate holdings have been operating at full occupancy. Approximately $2.9 million in capital investment focused on asset enhancement and maintenance and leasehold improvements.

Technology solutions were initiated to improve productivity and provide optimal customer service. Phase I of a new human resource/payroll system was completed, providing improved operational efficiencies and supporting future organizational growth.

Fortis Properties was bestowed three awards by the Building Owners and Managers Association, Newfoundland and Labrador Chapter: the *Pinnacle Award* for customer service, the *Team Excellence Award – Property Team of the Year* and the *Office Building of the Year* for Cabot Place.

All Fortis Properties hotels have been certified under the *Hotel Association of Canada*'s *GreenKey Eco-Rating Program*, which recognizes hotels, motels and resorts that are committed to improving their fiscal and environmental performance.

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

Fortis Properties and its employees recently received two hospitality awards. Delta Brunswick was recognized for its community involvement and leadership with the *Hotel Association of Canada*'s *Humanitarian Award*. The award is given to a property that has demonstrated dedication and responsiveness to community needs through volunteerism, donations and community leadership. The Company also received the *President's Award for North America* from Starwood Hotels and Resorts Worldwide, Inc., owners of the Sheraton and Four Points by Sheraton brands. The award is given to hotel owners that possess strong leadership and an ongoing commitment to a shared vision of community success in a manner consistent with the Starwood brand.

Our Community

Fortis employees are committed to helping improve the quality of life in the communities where we work and live.

We've got spirit! Team spirit. Community spirit. Employee spirit. Fortis employees show their caring spirit by opening up their hearts and rolling up their sleeves to help improve the quality of life in the communities where we work and live. The Fortis Group contributed more than $3 million in financial and in-kind donations in 2009 to community initiatives that are helping to make our world a better, brighter place.

Here are a few of the partnerships we were proud to be involved with during the year:

Terasen joined forces with the *Tynehead Hatchery*, operated by the non-profit volunteer Serpentine Enhancement Society, in Surrey, British Columbia to celebrate Earth Day. Volunteers released Chinook salmon fry and completed gardening and painting tasks.

FortisAlberta employees generated significant donations for eight local United Way chapters. The Company's *2009 United for a Cause* campaign raised $181,000 to improve the lives of individuals and families across Alberta.

FortisBC employees and families pitched in to help make the *Great Canadian Shoreline Cleanup* a success, collecting some 2,500 kilograms of garbage from the shoreline of the Columbia River in downtown Trail, British Columbia.

Heart and Stroke Foundation's Big Bike Ride.

Newfoundland Power contributed approximately $165,000 to *The Power of Life Project*. Five chemotherapy chairs were donated to the Cancer Centre Western Region and a blanket warmer was provided to the Burin Cancer Centre.

2009 Canada Games

Maritime Electric was one of the five *Friends of the 2009 Canada Games Sponsors*, which contributed a combined $250,000 to the national multi-sport and cultural event held on Prince Edward Island.

FortisOntario contributed $15,000 towards energy-efficient lighting for the Town of Fort Erie's new skate park and $10,000 towards the Town of Gananoque's *King Street Lighting Beautification Project*.

Belize Electricity was a major sponsor of the *4th Annual Belize Band Fest*, which provides an opportunity for young people to showcase their musical talent.

Caribbean Utilities hosted 36 high school and college students as part of the *2009 Summer Work Experience Program*.

Fortis Turks and Caicos was the main sponsor of the newly opened *Bright Community Park*, the principal public beach recreation and environmental park on Providenciales.

Fortis Properties helped raise $67,000 for the *Children's Wish Foundation of Canada* through a dinner and silent auction hosted by the Sheraton Hotel Newfoundland.

Management Discussion and Analysis

Dated March 2, 2010

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2009 Consolidated Financial Statements and Notes to the 2009 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2009 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 increase in average annual energy production from the Macal River in Belize by the Vaca hydroelectric generating facility; the expected timing of regulatory decisions; negligible electricity sales growth is expected at the Corporation's regulated utilities in the Caribbean for 2010; organic revenue growth at Fortis Properties' Hospitality Division is expected to continue to be challenged in 2010; consolidated forecasted gross capital expenditures for 2010 and in total over the five-year period from 2010 through 2014; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expected impacts on Fortis of the economic downturn; the expectation of no significant decrease in annual consolidated operating cash flows in 2010 as a result of any continuation of the economic downturn; the expectation that the subsidiaries will be able to source the cash required to fund their 2010 capital expenditure programs; the expectation that the Corporation and its utilities will continue to have reasonable access to capital in the near to medium terms; expected consolidated long-term debt maturities and repayments in 2010 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 2010; no material adverse credit rating actions are expected 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 2010; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of an increase in consolidated defined benefit net pension cost for 2010. 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 significant decline in capital spending in 2010; 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 continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; 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 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; no material decrease in market energy sales prices; 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; 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 supply; defined benefit pension *plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; market energy sales prices; changes in the current assumptions and expectations associated with the transition to International Financial Reporting Standards; 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, 2009.*

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

Corporate Overview and Strategy

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. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. In 2009, the Corporation's electricity distribution systems met a combined peak electricity demand of 5,986 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,234 terajoules ("TJ").

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. 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.

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 to customers at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The operating 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 earnings of the Corporation's regulated utilities are primarily determined under cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates, which factor into customer rate-setting mechanisms.

Fortis holds investments in non-regulated generation, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and 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.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. 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 following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

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 approximately 839,000 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 approximately 98,000 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 newly converted 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 480,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 159,000 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 Cominco Metals Ltd., the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant 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 the principal distributor of electricity in Newfoundland, serving more than 239,000 customers. Newfoundland Power 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 the principal distributor of electricity on Prince Edward Island, serving approximately 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 ten-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent 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 the principal distributor of electricity in Belize, Central America, serving approximately 76,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 25,000 customers. The Company has an installed generating capacity of 153 MW. Fortis holds an approximate 59 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Previously, Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results.

c. *Fortis Turks and Caicos:* Includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is the principal distributor of electricity in the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-powered generating capacity of 54 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, the 7-MW Chalillo and, as of March 2010, the 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 per cent interest in the Exploits Partnership and Abitibi holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro ("Newfoundland Hydro") under a 30-year power purchase agreement 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. The plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State:* Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, 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 2.8 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 per cent 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.

Financial Highlights

For the Years Ended December 31	2009	2008	Variance
Net Earnings Applicable to Common Shares *($ millions)*	**262**	245	17
Basic Earnings per Common Share *($)*	**1.54**	1.56	(0.02)
Diluted Earnings per Common Share *($)*	**1.51**	1.52	(0.01)
Weighted Average Number of Common Shares Outstanding *(millions)*	**170.2**	157.4	12.8
Revenue *($ millions)*	**3,637**	3,903	(266)
Dividends Paid per Common Share *($)*	**1.04**	1.00	0.04
Rate of Return on Average Book Common Shareholders' Equity *(%)*	**8.4**	8.7	(0.3)
Total Assets *($ millions)*	**12,160**	11,166	994
Cash Flow from Operating Activities *($ millions)*	**637**	661	(24)

Acquisitions: 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 northern Ontario.

In June 2009, FortisOntario acquired a 10 per cent 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.

In November 2008, Fortis Properties acquired the Sheraton Hotel Newfoundland for approximately $22 million, increasing hospitality operations by 301 rooms and 16,000 square feet of convention meeting space.

Key Trends and Risks: 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 in Canada and the United States. The primary focus will likely be investor-owned US-based utilities due to the limited number of opportunities to acquire investor-owned regulated gas and electric utility assets in Canada.

Persistently low long-term interest rates in Canada have negatively affected the formula-based allowed rate of return on common shareholders' equity ("ROE") at each of the Corporation's four largest regulated utilities. However, several regulators in Canada have reviewed the cost of capital of utilities they regulate and have set allowed ROEs for 2010 at levels higher than those that would have been determined under the previous ROE automatic adjustment formulas. The chart below highlights the trend in the allowed ROEs at each of the Corporation's four largest regulated utilities.

Approved Regulator-Allowed ROEs

(%)	2006	2007	2008	2009	2010
TGI	8.80	8.37	8.62	8.47/9.50 *(1)*	9.50
FortisAlberta	8.93	8.51	8.75	9.00 *(2)*	9.00 *(2)*
FortisBC	9.20	8.77	9.02	8.87	9.90
Newfoundland Power	9.24	8.60	8.95	8.95	9.00

(1) Set at 9.50 per cent, effective July 1, 2009

(2) Set for 2009, 2010 and, on an interim basis, 2011

The impact on the Corporation's consolidated earnings of lower allowed ROEs in recent years has been mitigated by earnings derived from increased rate bases and energy sales and the realization of operating cost efficiencies.

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, 2009, regulated utility assets comprised 93 per cent of total assets (December 31, 2008 – 92 per cent) and regulated utility assets in western Canada comprised 75 per cent of total regulatory assets (December 31, 2008 – 74 per cent). Organic earnings' growth from the Corporation's regulated utilities in Canada, therefore, is expected to be primarily driven by rate base growth at FortisAlberta, FortisBC and the Terasen Gas companies. The Corporation's other Canadian regulated electric utilities, Newfoundland Power, Maritime Electric and FortisOntario, are expected to generate slower earnings' growth.

Regulated assets in the Caribbean region, as a percentage of the Corporation's total regulated assets, were 8 per cent as at December 31, 2009 (December 31, 2008 – 10 per cent). Generally, the regulated rate of return on rate base assets ("ROA") in the Caribbean is higher than that 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 in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Economic growth had been strong in the Corporation's service territories in the Caribbean; however, the economic downturn unfavourably impacted sales growth in 2009 and is expected to have a similar impact in 2010. 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.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, which have the same regulator, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. However, the relationship of Belize Electricity with its regulator became tenuous in 2008 when the regulator issued a decision disallowing previously incurred fuel and purchased power costs and lowering the regulated ROA. The decision has and continues to negatively impacted Belize Electricity's financial health. Although the receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieving a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of its operations. The total assets of Belize Electricity comprise approximately 2 per cent of the Corporation's total assets.

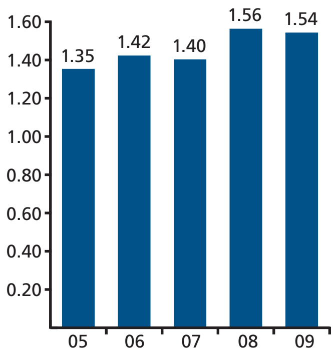
In Canada, regulator-approved negotiated settlement agreements were reached at the Terasen Gas companies for 2010 and 2011 customer gas rates and at FortisBC for 2010 customer electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of public hearing processes.

The Corporation's regulated gas and electric 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 subsidiary capital expenditure programs is mostly obtained at the regulated utility level. The subsidiaries issue debt mostly at terms ranging between 10 years and 30 years. As at December 31, 2009, approximately 81 per cent 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 $2.2 billion in credit facilities of which approximately $1.4 billion was unused as at December 31, 2009. With strong credit ratings and conservative capital structures, the Corporation and its utilities expect to continue to have reasonable access to long-term capital in 2010.

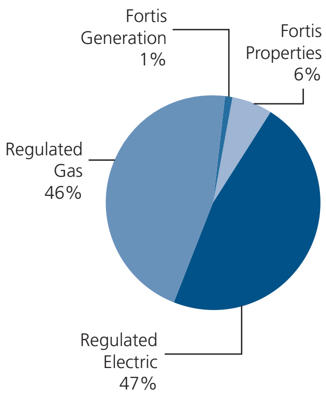
Common share dividend payments increased to $1.04 per share in 2009. Effective for the first quarter of 2010, a 7.7 per cent increase in the quarterly common share dividend to 28 cents from 26 cents translates into an annualized dividend of $1.12 and extends the Corporation's record of annual common share dividend increases to 37 consecutive years, the longest record of any public corporation in Canada.

For a complete discussion of the Corporation's business risks, including regulatory risk and the impact on the Corporation and its subsidiaries of recent economic conditions, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Basic Earnings per Common Share *($)*

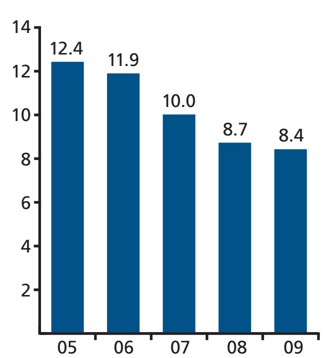


Revenue[(1)]
(year ended December 31, 2009)



(1) Excludes Corporate and Other

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



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $262 million in 2009, up $17 million from earnings of $245 million in 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 additional costs 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 deemed equity component of the total capital structure 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 in April 2009, and ongoing regulatory challenges at Belize Electricity.

Basic earnings per common share were $1.54 in 2009 compared to $1.56 in 2008. Basic earnings per common share in 2009 were diluted by the 11.7 million common share equity offering in December 2008, the net proceeds of which were primarily used to repay maturing long-term debt.

Revenue: Revenue was approximately $3.6 billion in 2009 compared to approximately $3.9 billion in 2008. The decrease was driven by the flow through to customers at the Terasen Gas companies and Caribbean Utilities of lower natural gas commodity and energy supply costs, respectively, combined with the loss of revenue from non-regulated generation operations in Ontario due to the expiration of the Rankine water rights in April 2009. The decrease was partially offset by the impact of basic customer rate increases, and customer growth mainly in Canada, in addition to the favourable impact of foreign exchange associated with translation of foreign currency-denominated revenue.

Rate of Return on Average Book Common Shareholders' Equity: The rate of return on average book common shareholders' equity was 8.4 per cent in 2009 compared to 8.7 per cent in 2008. The decline related to higher average book common shareholders' equity largely associated with the 11.7 million common share equity offering in December 2008.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $637 million in 2009 compared to $661 million in the previous year. The decrease was mainly due to the timing of the declaration of common share dividends, the timing and an increase in the amount of corporate income taxes paid at Newfoundland Power and 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. The decrease was partially offset by favourable changes in the Alberta Electric System Operator ("AESO") charges deferral account at FortisAlberta.

Dividends: Dividends paid per common share increased to $1.04 in 2009, up 4.0 per cent from $1.00 in 2008. Fortis increased its quarterly common share dividend 7.7 per cent, to 28 cents from 26 cents, commencing with the first quarter dividend paid on March 1, 2010. The Corporation's dividend payout ratio was 67.5 per cent in 2009 compared to 64.1 per cent in 2008.

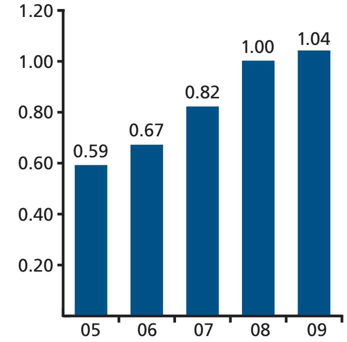
In December 2008, the Corporation's Amended and Restated Dividend Reinvestment and Share Purchase Plan (the "Dividend Reinvestment and Share Purchase Plan") provided a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009. The Corporation received $29 million from dividend reinvestments during 2009.

Asset Growth: Total assets increased almost 9 per cent to approximately $12.2 billion at the end of 2009 compared to approximately $11.2 billion at the end of 2008. The increase reflected 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. For a further discussion of the nature of the impact of the adoption of the amended accounting standard for income taxes, refer to the "Changes in Accounting Standards" section of this MD&A.

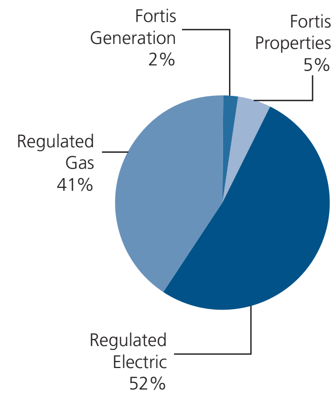
2009 Capital Expenditures: During 2009, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,024 million, up $89 million from $935 million in 2008. Total capital investment at the regulated utilities in western Canada in 2009 was approximately $768 million, representing approximately 75 per cent of total gross capital expenditures. Much of the capital investment was driven by customer growth and the need to enhance the reliability of energy systems. The larger capital projects during 2009 included the continued construction of the liquefied natural gas ("LNG") storage facility at TGVI, the installation of automated meter technology at FortisAlberta, the Okanagan Transmission Reinforcement Project at FortisBC and BECOL's 19-MW Vaca hydroelectric generating facility in Belize.

Financings: During 2009, Fortis and its regulated utilities raised more than $700 million in long-term debt. In July 2009, Fortis issued $200 million 30-year 6.51% unsecured debentures. The net proceeds from the debenture offering were used to repay in full the indebtedness outstanding under the Corporation's credit facility and for general corporate purposes. At the subsidiary level, TGI issued $100 million 30-year 6.55% unsecured debentures in February; FortisAlberta issued $100 million 30-year 7.06% unsecured debentures in February and $125 million 30-year 5.37% unsecured debentures in October; Newfoundland Power issued $65 million 30-year 6.606% first mortgage sinking fund bonds in May; FortisBC issued $105 million 30-year 6.10% unsecured debentures in June; and Caribbean Utilities issued US$30 million and US$10 million in May and July, respectively, 15-year 7.50% unsecured notes. 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, to repay $110 million of maturing debt at TGI and FortisBC and to finance capital expenditures.

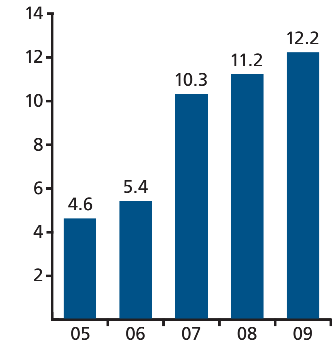
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2009)



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



Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31 *($ millions)*	2009	2008	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**117**	118	(1)
Regulated Electric Utilities – Canadian			
FortisAlberta	**60**	46	14
FortisBC	**37**	34	3
Newfoundland Power	**32**	32	–
Other Canadian[(1)]	**20**	14	6
	149	126	23
Regulated Electric Utilities – Caribbean[(2)]	**27**	17	10
Non-Regulated – Fortis Generation[(3)]	**16**	30	(14)
Non-Regulated – Fortis Properties[(4)]	**24**	23	1
Corporate and Other	**(71)**	(69)	(2)
Net Earnings Applicable to Common Shares	**262**	245	17

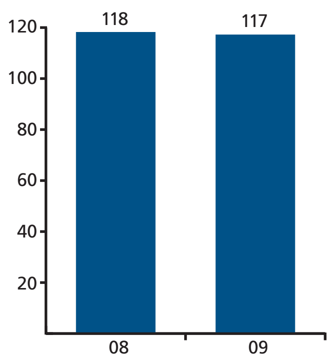
(1) Includes Algoma Power from October 2009

(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results and resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities for the year ended December 31, 2008. During 2009, the financial reporting periods of the Corporation coincided with the financial reporting periods of Caribbean Utilities.

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

(4) Includes the results of the Holiday Inn Select Windsor from April 2009 and the Sheraton Hotel Newfoundland from November 2008, the dates of acquisition

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



REGULATED UTILITIES

The Corporation's primary business is regulated utilities. In 2009, regulated earnings in Canada and the Caribbean represented approximately 88 per cent (2008 – 83 per cent) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 93 per cent of the Corporation's total assets as at December 31, 2009 (December 31, 2008 – 92 per cent).

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2009 were $117 million (2008 – $118 million), which represented approximately 40 per cent of the Corporation's total regulated earnings (2008 – 45 per cent). Regulated Gas Utilities – Canadian assets were approximately $5.0 billion as at December 31, 2009 (December 31, 2008 – $4.6 billion), which represented approximately 44 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 45 per cent).

Terasen Gas Companies

Financial Highlights

Years Ended December 31	2009	2008	Variance
Gas Volumes *(TJ)*	**207,230**	221,122	(13,892)
($ millions)			
Revenue	**1,663**	1,902	(239)
Energy Supply Costs	**1,022**	1,268	(246)
Operating Expenses	**268**	253	15
Amortization	**102**	97	5
Finance Charges	**121**	129	(8)
Corporate Taxes	**33**	37	(4)
Earnings	**117**	118	(1)

Gas Volumes: Gas volumes decreased 13,892 TJ, or 6.3 per cent, year over year. The following is a breakdown of gas volumes by major customer category.

Gas Volumes by Major Customer Category

Years Ended December 31

(TJ)	**2009**	2008	Variance
Core – residential and commercial	**125,238**	132,867	(7,629)
Industrial	**6,038**	6,337	(299)
Total sales volumes	**131,276**	139,204	(7,928)
Transportation volumes	**60,067**	63,572	(3,505)
Throughput under fixed revenue contracts	**15,887**	18,346	(2,459)
Total Gas Volumes	**207,230**	221,122	(13,892)

The decrease in gas volumes to core customers was mainly due to lower average consumption as a result of warmer temperatures experienced in the cooler months in 2009 compared to 2008. The decrease in gas volumes for all other customers was mainly due to the negative impact of the economic downturn.

The Terasen Gas companies earn approximately the same margin regardless of whether a customer contracts for the purchase of natural gas or contracts 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 forecasted to set customer gas rates do not materially affect earnings.

During 2009, net customer additions at the Terasen Gas companies totalled approximately 8,200, bringing the total customer count to approximately 939,600 as at December 31, 2009. During 2008, net customer additions at the Terasen Gas companies totalled approximately 12,800. Continuing weak housing and construction markets, due to slower economic growth, and growth in multi-family housing, where natural gas use is less prevalent compared to single-family housing, has resulted in lower customer growth year over year.

Revenue: Revenue was approximately $1.7 billion for 2009 compared to $1.9 billion for 2008. The decrease was largely due to the lower commodity cost of natural gas charged to customers and lower consumption, partially offset by higher basic customer delivery rates and the rate revenue accrual related to an increase, effective July 1, 2009, in the allowed ROEs for the Terasen Gas companies.

The allowed ROE was increased to 9.50 per cent from 8.47 per cent for TGI and increased to 10.00 per cent from 9.17 per cent for TGVI and TGWI.

Effective January 1, 2009, basic customer delivery rates at TGI increased approximately 6 per cent while basic customer delivery rates at TGVI increased up to 5 per cent based on customer rate class. The basic customer delivery rates, however, reflected the impact of a decrease in the allowed ROE, effective for the first half of 2009, to 8.47 per cent from 8.62 per cent for TGI and to 9.17 per cent from 9.32 per cent for TGVI and TGWI.

Earnings: Earnings were $117 million for 2009 compared to $118 million for 2008. Excluding a $5.5 million tax reduction during the third quarter of 2008 associated with the settlement of historical corporate tax matters and $6 million ($5 million after tax) of costs associated with the conversion of Whistler customer appliances from propane to natural gas, which increased operating expenses in 2009, earnings were approximately $9.5 million higher year over year. The increase was mainly due to the $6 million after-tax impact of the rate revenue accrual related to the increase in the allowed ROEs, effective July 1, 2009, as discussed above, higher basic customer delivery rates, lower finance charges and a lower effective corporate income tax rate. The increase was partially offset by higher operating expenses due to increased labour and employee-benefit costs, and increased amortization costs due to continued investment in capital assets.

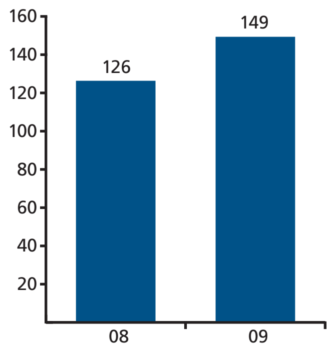
The decrease in the effective corporate income tax rate was primarily due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008.

As reflected in basic customer delivery rates for 2009, finance charges were lower year over year due to decreased borrowing rates and lower borrowings under credit facilities.

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

Outlook: Allowed ROEs for 2010 have been set by the regulator at 9.50 per cent for TGI and 10.00 per cent for TGVI and TGWI. The deemed equity component of the total capital structure for TGI has increased, effective January 1, 2010, to 40 per cent. Customer rates at the Terasen Gas companies have been approved by the regulator, effective January 1, 2010.

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



A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for 2010 for the Terasen Gas companies is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2009 were $149 million (2008 – $126 million), which represented approximately 51 per cent of the Corporation's total regulated earnings (2008 – 48 per cent). Regulated Electric Utilities – Canadian assets were approximately $5.4 billion as at December 31, 2009 (December 31, 2008 – $4.6 billion), which represented approximately 48 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 45 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31	**2009**	2008	Variance
Energy Deliveries *(GWh)*	**15,865**	15,722	143
($ millions)			
Revenue	**331**	300	31
Operating Expenses	**132**	130	2
Amortization	**94**	85	9
Finance Charges	**50**	42	8
Corporate Tax Recovery	**(5)**	(3)	(2)
Earnings	**60**	46	14

Energy Deliveries: Energy deliveries at FortisAlberta increased 143 gigawatt hours ("GWh"), or 0.9 per cent, year over year, mainly due to an increase in residential, commercial, farm and irrigation customers, partially offset by a decrease in oilfield customers. Cooler than normal temperatures during the first quarter of 2009 also favourably affected energy deliveries for the year.

As a significant portion of the Company'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: Revenue was $31 million higher than in the previous year, mainly due to an 8.6 per cent increase in customer distribution rates, effective January 1, 2009, reflecting the impact of ongoing investment in electrical infrastructure, and customer and load growth. Revenue also increased due to the rate revenue accrual of approximately $4 million related to the impact of the increase in the allowed ROE to 9.00 per cent, effective January 1, 2009, from an interim allowed ROE of 8.51 per cent and the increase in the deemed equity component of the total capital structure to 41 per cent from 37 per cent for 2009.

Earnings: Earnings were $14 million higher than in the previous year. The impact of the increase in revenue and higher corporate tax recoveries was partially offset by: (i) higher amortization costs associated with continued investment in capital assets; (ii) increased finance charges due to higher debt levels in support of the Company's significant capital expenditure program, partially offset by the impact of lower interest rates on credit facility borrowings; and (iii) higher operating expenses mainly due to higher labour and employee-benefit costs associated with increased salaries and number of employees, partially offset by lower general operating costs. Corporate tax recoveries were higher due to higher future income tax recoveries associated with an increase in regulatory deferrals subject to future income tax recoveries.

Outlook: FortisAlberta's allowed ROE for 2010 has been set by the regulator at 9.00 per cent, unchanged from 2009. An interim customer distribution rate increase of 7.5 per cent, effective January 1, 2010, has been approved by the regulator pending final approval of FortisAlberta's 2010 and 2011 Revenue Requirements Application.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta is provided under the heading "Regulatory Highlights". A summary of FortisAlberta's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

FortisBC

Financial Highlights

Years Ended December 31	2009	2008	Variance
Electricity Sales *(GWh)*	**3,157**	3,087	70
($ millions)			
Revenue	**253**	237	16
Energy Supply Costs	**72**	68	4
Operating Expenses	**70**	67	3
Amortization	**37**	34	3
Finance Charges	**32**	28	4
Corporate Taxes	**5**	6	(1)
Earnings	**37**	34	3

Electricity Sales: Electricity sales at FortisBC increased 70 GWh, or 2.3 per cent, year over year, primarily due to growth in residential, general service and indirect wholesale customers, partially offset by a decrease in the number of industrial customers. Cooler than normal temperatures during the first quarter of 2009 also favourably impacted electricity sales for the year.

Revenue: Revenue was $16 million higher than in the previous year, driven by: (i) a 4.6 per cent increase in customer electricity rates, effective January 1, 2009; (ii) a 2.2 per cent increase in customer electricity rates, effective September 1, 2009, as a result of the flow through to customers of increased purchased power costs from BC Hydro; and (iii) electricity sales growth, partially offset by a decrease in other revenue driven by an increase in performance-based rate-setting ("PBR") incentive adjustments owing to customers. Customer electricity rates for 2009 reflected the impact of ongoing investment in electrical infrastructure and an allowed ROE of 8.87 per cent compared to 9.02 per cent for 2008.

Earnings: Earnings were $3 million higher than in the previous year. The impact of the increase in customer electricity rates, customer growth and a lower effective corporate income tax rate was partially offset by: (i) higher energy supply costs associated with increased electricity sales and the impact of higher average prices for purchased power, combined with a higher proportion of purchased power versus energy generated from Company-owned hydroelectric generating plants and the receipt of $0.6 million of insurance proceeds during the second quarter of 2008 associated with a turbine failure in 2006; (ii) higher operating expenses mainly due to higher labour costs and general inflationary cost increases, and higher property taxes and water fees; (iii) increased amortization costs associated with continued investment in capital assets; and (iv) higher finance charges, reflecting increased debt levels in support of the Company's capital expenditure program, combined with increased credit facility renewal fees, partially offset by the impact of lower interest rates on credit facility borrowings.

The decrease in the effective corporate income tax rate was due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008, combined with a lower statutory income tax rate.

Outlook: FortisBC's allowed ROE for 2010 has been set at 9.90 per cent, up from 8.87 per cent for 2009. In December 2009, FortisBC received regulatory approval of a Negotiated Settlement Agreement ("NSA") pertaining to the Company's 2010 Revenue Requirements Application, resulting in a general customer electricity rate increase of 6.0 per cent, effective January 1, 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC is provided under the heading "Regulatory Highlights". A summary of FortisBC's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31	2009	2008	Variance
Electricity Sales *(GWh)*	**5,299**	5,208	91
($ millions)			
Revenue	**527**	517	10
Energy Supply Costs	**346**	337	9
Operating Expenses	**52**	50	2
Amortization	**46**	45	1
Finance Charges	**34**	33	1
Corporate Taxes	**16**	19	(3)
Non-Controlling Interest	**1**	1	–
Earnings	**32**	32	–

Electricity Sales: Electricity sales at Newfoundland Power increased 91 GWh, or 1.7 per cent, year over year, primarily due to the impact of customer growth and higher average consumption.

Revenue: Revenue was $10 million higher than in the previous year. The increase was driven by increased electricity sales and higher other revenue, partially offset by lower amortization to revenue of certain regulatory liabilities, in accordance with prescribed regulatory orders. The allowed ROE of 8.95 per cent for 2009 remained unchanged from 2008 and, consequently, did not impact customer electricity rates for 2009.

Earnings: Earnings were comparable year over year. Higher electricity sales, an increase in other revenue and a lower effective corporate income tax rate were offset mainly by: (i) the impact of higher demand charges from Newfoundland Hydro, associated with meeting peak load requirements during the winter season; (ii) higher operating expenses, driven by wage, inflationary and regulatory cost increases and an increase in regulator assessment costs due to the timing of the recognition of these costs in 2008, partially offset by a reduction in insurance costs; (iii) increased amortization costs, driven by the impact of continued investment in capital assets; and (iv) higher finance charges, reflecting increased debt levels in support of the Company's capital expenditure program, partially offset by the impact of lower interest rates on credit facility borrowings.

The decrease in the effective corporate income tax rate was primarily due to higher deductions taken for tax purposes compared to accounting purposes in 2009 compared to 2008 and a lower statutory income tax rate.

Outlook: Newfoundland Power's allowed ROE for 2010 has been set at 9.00 per cent, up from 8.95 per cent for 2009. The regulator has approved an overall average increase in basic customer electricity rates of approximately 3.5 per cent, effective January 1, 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power is provided under the heading "Regulatory Highlights". A summary of Newfoundland Power's forecast gross capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Other Canadian Electric Utilities[(1)]

Financial Highlights

Years Ended December 31	2009[(2)]	2008	Variance
Electricity Sales *(GWh)*	**2,195**	2,182	13
($ millions)			
Revenue	**279**	262	17
Energy Supply Costs	**183**	177	6
Operating Expenses	**32**	28	4
Amortization	**19**	18	1
Finance Charges	**19**	18	1
Corporate Taxes	**6**	7	(1)
Earnings	**20**	14	6

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

In October 2009, FortisOntario acquired Great Lakes Power Distribution Inc., subsequently renamed Algoma Power, for an aggregate purchase price of $75 million.

In June 2009, FortisOntario acquired a 10 per cent interest in Grimsby Power for approximately $1 million.

Electricity Sales: Electricity sales at Other Canadian Electric Utilities increased 13 GWh, or 0.6 per cent, year over year. Excluding electricity sales at Algoma Power, electricity sales decreased 33 GWh, or 1.5 per cent, year over year. The decrease was driven by lower average consumption, mainly due to the impact of the economic downturn and the unfavourable impact on consumption due to more moderate temperatures experienced in Ontario in the second and third quarters of 2009, compared to the same periods in 2008, partially offset by the favourable impact on consumption due to cooler temperatures experienced in Ontario in the first quarter of 2009 compared to the same quarter of 2008.

Revenue: Revenue was $17 million higher than in the previous year. Excluding the impact of an approximate $3 million ($2 million after tax) one-time charge at FortisOntario associated with the repayment, during the second quarter of 2008, of a refund received during the fourth quarter of 2007 associated with cross-border transmission interconnection agreements, revenue increased $14 million, $8 million of which related to Algoma Power. The remaining increase in revenue year over year was due to the impact of an average 5.3 per cent increase in customer electricity rates at Maritime Electric, effective April 1, 2009, and a 5.1 per cent, 11.7 per cent and 8.4 per cent increase in customer electricity distribution rates in Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009, partially offset by the impact of lower electricity sales and the flow through to customers of lower energy supply costs at FortisOntario. The higher customer electricity rates at Maritime Electric reflected an increase in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings.

Earnings: Earnings were $6 million higher than in the previous year. Excluding a one-time $3 million favourable adjustment to future income taxes during the fourth quarter of 2009 related to prior periods at FortisOntario and the $2 million after-tax one-time charge at FortisOntario associated with the repayment, during the second quarter of 2008, of the interconnection agreement-related refund, earnings increased $1 million year over year. The increase reflected lower operating expenses at FortisOntario due to the timing of maintenance expenses and a focus on capital projects. Algoma Power contributed $0.1 million to earnings in 2009.

Outlook: In January 2010, Maritime Electric filed a regulatory application requesting an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009.

During the first half of 2010, FortisOntario expects to file a new electricity rate application for Algoma Power for rates effective July 1, 2010, using 2010 as a forward test year and an allowed ROE of 9.75 per cent.

Electricity distribution rates for Canadian Niagara Power customers have been approved by the regulator for the period May 1, 2009 through April 30, 2010 and were rebased using 2009 as a forward test year. Regulatory applications were filed in the fourth quarter of 2009, under the Third-Generation Incentive Rate Mechanism, for electricity distribution rates, effective May 1, 2010. An allowed ROE of 9.75 per cent for 2010 will be applicable to utilities in Ontario regulated by the Ontario Energy Board ("OEB"), including FortisOntario, upon filing full cost of service applications in 2010.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Maritime Electric and FortisOntario is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2009 was $27 million (2008 – $17 million), which represented approximately 9 per cent of the Corporation's total regulated earnings (2008 – 7 per cent). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2009 (December 31, 2008 – $1.0 billion), which represented approximately 8 per cent of the Corporation's total regulated assets as at December 31, 2009 (December 31, 2008 – 10 per cent).

Regulated Electric Utilities – Caribbean(1)

Financial Highlights

Years Ended December 31	**2009**	2008(2)	Variance
Average US:CDN Exchange Rate (3)	**1.13**	1.08	0.05
Electricity Sales *(GWh)*	**1,140**	1,203	(63)
($ millions)			
Revenue	**339**	408	(69)
Energy Supply Costs	**192**	273(4)	(81)
Operating Expenses	**54**	55	(1)
Amortization	**37**	36	1
Finance Charges	**16**	16	–
Corporate Taxes	**2**	2	–
Non-Controlling Interest	**11**	9	2
Earnings	**27**	17	10

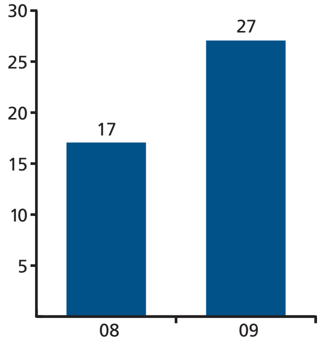
(1) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

(2) During 2008, Caribbean Utilities changed its fiscal year end from April 30 to December 31, resulting in the Corporation consolidating 14 months of electricity sales and financial results of Caribbean Utilities for the year ended December 31, 2008. Prior to the fourth quarter of 2008, Fortis was consolidating the financial results of Caribbean Utilities on a two-month lag basis. During 2009, the financial reporting periods of the Corporation coincided with the financial reporting periods of Caribbean Utilities.

(3) 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.

(4) Energy supply costs during the second quarter of 2008 included an $18 million (BZ$36 million) charge as a result of a regulatory rate decision by the Public Utilities Commission in Belize in June 2008.

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



Electricity Sales: Electricity sales at Regulated Electric Utilities – Caribbean decreased 63 GWh, or 5.2 per cent, year over year. Electricity sales and financial results for the segment for 2008, however, included electricity sales and financial results of Caribbean Utilities for the 14 months ended December 31, 2008, due to a change in the utility's fiscal year end in 2008. When comparing electricity sales for the period from January to December 2009 to the same 12-month period in 2008 for Caribbean Utilities, electricity sales for the segment increased approximately 2 per cent for the year. The increase reflected the loss of electricity sales during the third and fourth quarters of 2008 at Fortis Turks and Caicos as a result of Hurricane Ike, including the delayed reopening for the fall 2008 tourist season of several large hotels on the Turks and Caicos Islands. Hurricane Ike struck the Turks and Caicos Islands in early September 2008. Tempering electricity sales growth year over year, however, was the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries.

Excluding the two additional months of contribution from Caribbean Utilities in 2008, annualized electricity sales growth in 2008 was approximately 6 per cent.

Revenue: Revenue was $69 million lower than in the previous year. Excluding the approximate $13 million favourable impact of foreign exchange associated with the translation of foreign currency-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar year over year, revenue decreased approximately $82 million. The decrease was driven by the flow through to customers of lower energy supply costs at Caribbean Utilities and Fortis Turks and Caicos and two additional months of contribution from Caribbean Utilities in fiscal 2008 (November and December 2007). Partially offsetting the above factors was the impact of: (i) a 2.4 per cent increase in basic customer electricity rates at Caribbean Utilities, effective June 1, 2009; (ii) an increase in the cost of power component of the average customer electricity rate at Belize Electricity, effective July 1, 2008; (iii) $1 million associated with a favourable appeal judgment at Fortis Turks and Caicos related to a customer rate classification matter; and (iv) the approximate 2 per cent increase in annualized electricity sales. Tempering revenue growth was the impact of: (i) a decrease in the value-added delivery ("VAD") component of the average customer electricity rate at Belize Electricity, effective July 1, 2008, due to a decrease in the allowed ROA; and (ii) a change in the methodology at Belize Electricity for recording customer installation fees and the impact of refunding certain installation fees previously collected. Customer installation fees at Belize Electricity are now recorded as a capital contribution on the balance sheet rather than as revenue on the statement of earnings.

Earnings: Earnings' contribution was $10 million higher than in the previous year. Excluding: (i) a $13 million reduction in earnings during the second quarter of 2008, representing the Corporation's approximate 70 per cent share of $18 million of disallowed previously incurred fuel and purchased power costs as a result of the June 2008 regulatory rate decision at Belize Electricity; (ii) two additional months of contribution from Caribbean Utilities in fiscal 2008 (November and December 2007) of approximately $1.5 million; and (iii) approximately $1 million associated with favourable foreign currency translation, earnings' contribution decreased $2.5 million year over year. Factors decreasing earnings' contribution included: (i) the lower allowed ROA at Belize Electricity, effective July 1, 2008; (ii) higher operating expenses, excluding foreign exchange impacts, driven by increased employee, legal and regulatory costs and bad debt expense, partially offset by an increase in capitalized general and administrative expenses, as prescribed under Caribbean Utilities' T&D licence, effective April 2008; and (iii) the favourable impact on energy supply costs in 2008 associated with a change in the fuel cost recovery mechanism at Caribbean Utilities. Included in Caribbean Utilities' T&D licence is a new mechanism for the flow through to customers of the cost of fuel and oil, which eliminates favourable or adverse timing differences in fuel and oil cost recovery for reporting periods subsequent to April 30, 2008. The above factors were partially offset by: (i) the approximate $1.5 million favourable impact of a change in depreciation estimates at Fortis Turks and Caicos; (ii) approximately $1 million associated with a favourable appeal judgment at Fortis Turks and Caicos, as described above; and (iii) 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 in 2009. Earnings were also favourably impacted by the 2.4 per cent basic customer electricity rate increase at Caribbean Utilities and the approximate 2 per cent increase in annualized electricity sales.

Caribbean Utilities met a record peak demand of 97.5 MW in August 2009 and Fortis Turks and Caicos met a combined record peak demand of 29.6 MW in July 2009. In May 2009, Fortis Turks and Caicos commissioned two diesel-powered generating units, increasing the Company's generating capacity by 6.6 MW to 54 MW. Fortis Turks and Caicos has also entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for a total of approximately US$12 million ($13 million) for delivery in mid-2010 and early 2011.

Outlook: Electricity sales growth at the Corporation's regulated utilities in the Caribbean is expected to be negligible for 2010, reflecting the expected continuation of the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries in the Caribbean region.

In October 2009, the Comisión Federal de Electricidad ("CFE") of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010. CFE has stated that its generating capacity has been significantly limited as a result of problems with gas availability, generation equipment and shortfalls in hydroelectric production. CFE is proposing to negotiate a new contract to provide up to 50 MW of economic and emergency energy to Belize Electricity. CFE continues to supply Belize Electricity with power when available. There is sufficient in-country generation to meet energy demand in Belize without supply from CFE.

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 under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

NON-REGULATED

Non-Regulated – Fortis Generation[(1)]

Financial Highlights

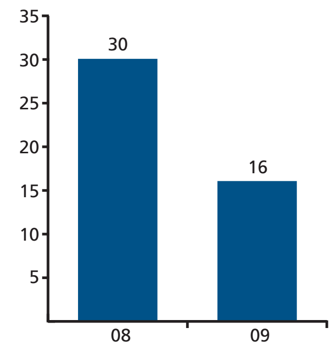
Years Ended December 31	2009[(2)]	2008	Variance
Energy Sales *(GWh)*	**583**	1,217	(634)
($ millions)			
Revenue	**39**	82	(43)
Energy Supply Costs	**2**	7	(5)
Operating Expenses	**11**	14	(3)
Amortization	**5**	10	(5)
Finance Charges	**2**	8	(6)
Corporate Taxes	**3**	10	(7)
Non-Controlling Interest	**–**	3	(3)
Earnings	**16**	30	(14)

(1) Includes the operations of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

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

Energy Sales: Energy sales from Non-Regulated – Fortis Generation decreased 634 GWh, or 52.1 per cent, year over year. As anticipated, 440 GWh of the total decrease in energy sales was due to the expiration on April 30, 2009, at the end of a 100-year term, of the water rights of the Rankine hydroelectric generating facility in Ontario. In addition, 158 GWh of the total decrease in energy sales related to generation operations in central Newfoundland. Energy sales for 2009 included sales related to central Newfoundland operations for only 1½ months compared to the entire year in 2008, due to the discontinuance of the consolidation method of accounting for these operations in February 2009, necessitated by the actions of the Government of Newfoundland and Labrador related to its expropriation of the assets of the Exploits Partnership (see the "Critical Accounting Estimates – Contingencies" section of this MD&A). The remaining decrease in total energy sales was mainly due to lower production in Belize and Upper New York State. Production levels were primarily a function of rainfall levels, in addition to the impact of maintenance downtime of one unit at the Chalillo hydroelectric generating facility in Belize for about 1½ months during the third quarter of 2009.

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



Revenue: Revenue was $43 million lower than in the previous year. The primary factors decreasing revenue were: (i) the loss of revenue subsequent to the expiration of the water rights of the Rankine hydroelectric generating facility, as described above; (ii) the impact of the discontinuance of the consolidation method of accounting for the financial results of the hydroelectric generation operations in central Newfoundland during the first quarter of 2009, as described above; (iii) lower average wholesale market energy prices per megawatt hour ("MWh") in Upper New York State, which were US$38.40 for 2009 compared to US$71.10 for 2008; (iv) decreased production in Upper New York State; and (v) lower average wholesale market energy prices per MWh in Ontario related to revenue earned associated with the Rankine facility, which were $36.83 for January through April in 2009 compared to $49.70 for the same period in 2008. The above factors were partially offset by the approximate $2 million favourable impact of foreign currency translation.

Earnings: Earnings were $14 million lower than in the previous year, driven by the expiration of the Rankine water rights, lower average wholesale market energy prices in Upper New York State and Ontario and the impact of lower production in Upper New York State. The decrease in earnings was partially offset by higher interest revenue associated with inter-company lending from non-regulated to regulated operations in Ontario, which reduced finance charges, and the approximate $1 million favourable impact of foreign currency translation. Earnings' contribution associated with the Rankine hydroelectric generating facility was $3.5 million for 2009 compared to approximately $16 million for 2008.

Outlook: The US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize will be commissioned in March 2010. The facility is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

Further information on forecast non-regulated utility capital expenditures for 2010 is provided under the heading "Liquidity and Capital Resources – Capital Program".

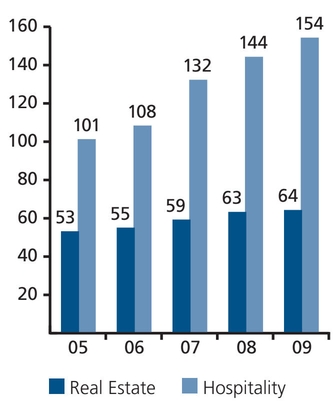
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2009**	2008	Variance
Hospitality Revenue	**154**	144	10
Real Estate Revenue	**64**	63	1
Total Revenue	**218**	207	11
Operating Expenses	**146**	135	11
Amortization	**16**	15	1
Finance Charges	**22**	24	(2)
Corporate Taxes	**10**	10	–
Earnings	**24**	23	1

Fortis Properties
Revenue *($ millions)*



Revenue: Hospitality revenue was $10 million higher than in the previous year, driven by revenue contribution from the Sheraton Hotel Newfoundland, which was acquired in November 2008, and the Holiday Inn Select Windsor in Ontario, which was acquired in April 2009, partially offset by decreased revenue in all regions related to the remainder of the Company's hotel operations due to the economic downturn.

Revenue per available room ("RevPAR") was $76.55 for 2009 compared to $80.39 for 2008. The decrease in RevPAR was mainly due to lower occupancies in all of the Company's operating regions, the most significant of which were experienced in western Canada and Ontario.

Real Estate revenue was $1 million higher than in the previous year. The increase reflected growth in all operating regions. The occupancy rate of the Real Estate Division was 96.2 per cent as at December 31, 2009 compared to 96.8 per cent as at December 31, 2008. The decrease in the occupancy rate was primarily associated with a property in rural Newfoundland.

Earnings: Earnings were $1 million higher than in the previous year. Contributions from the Sheraton Hotel Newfoundland and the Holiday Inn Select Windsor, combined with increased contribution from the Real Estate Division and lower finance charges, were partially offset by the impact of generally lower occupancies at the remainder of the Company's hotel operations. Finance charges decreased mainly due to lower external debt balances resulting from regularly scheduled debt repayments.

Operating expenses were $11 million higher than in the previous year, primarily related to the Sheraton Hotel Newfoundland, including non-recurring transitional operating costs incurred during the first quarter of 2009, and the Holiday Inn Select Windsor. The increase was partially offset by overall cost reductions realized in the balance of the Hospitality Division and lower operating expenses incurred at the Real Estate Division. The decrease in operating expenses incurred at the Real Estate Division mainly related to the reclassification to amortization costs during 2009 of certain major operating expenses recoverable from tenants, which were previously deferred and amortized to operating expenses.

Outlook: Same-hotel revenue declined at Fortis Properties' Hospitality Division in 2009 and organic revenue growth will continue to be challenged in 2010 as a result of the economic downturn and its impact on leisure and business travel and hotel stays.

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 to reduce the risk of vacancy exposure.

Corporate and Other(1)

Financial Highlights

Years Ended December 31

($ millions)	**2009**	2008	Variance
Revenue	**27**	26	1
Operating Expenses	**14**	16	(2)
Amortization	**8**	8	–
Finance Charges(2)	**79**	80	(1)
Corporate Tax Recovery	**(21)**	(23)	2
Preference Share Dividends	**18**	14	4
Net Corporate and Other Expenses	**(71)**	(69)	(2)

(1) Includes Fortis net corporate expenses and the net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

(2) Includes dividends on preference shares classified as long-term liabilities

Revenue: Revenue was $1 million higher than in the previous year. The increase was driven by higher inter-company interest revenue due to increased inter-company lending, partially offset by lower revenue contribution from CWLP due to the impact of a decrease in the number of customer contracts.

Net Corporate and Other Expenses: Net corporate and other expenses were $2 million higher than in the previous year. Excluding a $1 million favourable corporate tax adjustment at Fortis during 2009 and a $2 million tax reduction recorded in 2008 associated with the settlement of historical corporate tax matters at Terasen, net corporate and other expenses were $1 million higher year over year. The increase was due to higher preference share dividends, due to the issuance of First Preference Shares, Series G during the second quarter of 2008, and lower earnings' contribution from CWLP, partially offset by decreased operating expenses and lower finance charges.

Operating expenses decreased due to lower business development costs at Fortis, partially offset by higher corporate legal and consulting fees and employee-benefit costs at Terasen.

Finance charges decreased as a result of lower average credit facility borrowings in 2009 compared to 2008 and lower interest rates charged on those borrowings, partially offset by interest costs associated with the $200 million 6.51% unsecured debentures issued in July 2009 and the unfavourable impact of foreign exchange associated with the translation of US dollar-denominated interest expense.

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

Regulatory Highlights

The nature of regulation and summary of 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 (%) 2008	2009	2010	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		Cost of Service ("COS")/ROE
TGI	British Columbia Utilities Commission ("BCUC")	40[(1)]	8.62	8.47 (pre-July 1, 2009) 9.50 (post-July 1, 2009)	9.50	TGI: 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009
TGVI	BCUC	40	9.32	9.17 (pre-July 1, 2009) 10.00 (post-July 1, 2009)	10.00	ROEs established by the BCUC, effective July 1, 2009, as a result of a cost of capital decision in 2009. Previously, the allowed ROEs were set using an automatic adjustment formula tied to long-term Canada bond yields. Future Test Year
FortisBC	BCUC	40	9.02	8.87	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 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[(2)]	8.75	9.00	9.00	COS/ROE ROE established by the AUC, effective January 1, 2009, as a result of a generic cost of capital decision in 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	8.95 +/– 50 bps	9.00 +/– 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	10.00	9.75	9.75[(3)]	COS/ROE Future Test Year
FortisOntario	OEB					
	Canadian Niagara Power	40[(4)]	9.00	8.01	9.75[(5)]	Canadian Niagara Power – COS/ROE
	Algoma Power	50	N/A	8.57	9.75	Algoma Power – COS/ROE and subject to Rural Rate Protection Subsidy program
	Franchise Agreement Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2004 historical test year for 2008; 2009 test year beginning in 2009 Algoma Power – 2007 historical test year for 2009; 2010 test year for 2010
				ROA		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00	10.00	–[(6)]	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	9.00 – 11.00	7.75 – 9.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new T&D licence, 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 with the Energy Commission	N/A	17.50[(7)]	17.50[(7)]	17.50[(7)]	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 2008 and 2009, the allowed deemed equity component of the capital structure was 35 per cent.
(2) Effective January 1, 2009. For 2008, the allowed deemed equity component of the capital structure was 37 per cent.
(3) Subject to regulatory approval
(4) Effective May 1, 2010. For 2009, effective May 1, the allowed deemed equity component of the capital structure was 43.3 per cent.
(5) Subject to Canadian Niagara Power filing a full cost of service application in 2010
(6) Allowed ROA to be settled once regulatory matters are resolved
(7) Amount provided under licence. Actual ROAs achieved in 2008 and 2009 were 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	• Every three months TGI and TGVI review natural gas and propane commodity rates with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane, while mid-stream rates are reviewed by the BCUC annually in December. As approved by the BCUC, the commodity rate for natural gas was unchanged for most customers and the commodity rate for propane and the mid-stream rate for natural gas decreased, all effective January 1, 2009. Effective April 1, 2009, the BCUC approved decreases in the commodity rates for natural gas and propane. Effective July 1, 2009, the BCUC approved the commodity rate for natural gas as unchanged for customers in most service regions and approved an increase in the commodity rate for propane for customers in Revelstoke. Effective October 1, 2009, the BCUC approved a decrease in commodity rates for natural gas for customers in the Lower Mainland, Fraser Valley and Interior service areas. Effective January 1, 2010, the BCUC approved an increase in mid-stream rates for natural gas and kept commodity rates for natural gas unchanged for customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenay service areas. The BCUC also approved an increase in commodity rates for propane for customers in Revelstoke, an increase in commodity rates for natural gas for customers in Fort Nelson and a decrease in commodity rates for natural gas for customers in Whistler, effective January 1, 2010. • In December 2008, the BCUC approved a basic customer delivery rate increase of approximately 6 per cent at TGI and approved basic customer delivery rate increases of up to 5 per cent at TGVI based on customer rate class. Basic customer delivery rates for 2009 reflected the decrease in the allowed ROE for 2009 to 8.47 per cent at TGI and to 9.17 per cent at TGVI, resulting from the application of ROE automatic adjustment formulas. • In March 2009, TGI received approval for its application with the BCUC to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River, serving Vancouver and Richmond. The project is expected to be completed in 2010 for a total cost of approximately $27 million. • In April 2009, TGI received approval from the BCUC for its new $41.5 million Energy Efficiency and Conservation Program to provide customers with enhanced tools and incentives to manage their natural gas consumption, reduce their energy costs and lower their greenhouse gas emissions. The program began in summer 2009. • In June 2009, the BCUC approved TGI's application requesting to sell LNG as a transportation fuel source for fleet vehicles. • Effective June 1, 2009, the BCUC approved an average 12 per cent decrease in basic customer delivery rates at TGWI. Effective July 1, 2009, the BCUC also approved an approximate 10 per cent decrease in commodity rates at TGWI. • 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 the deemed equity component of TGI's total capital structure, effective January 1, 2010, to 40 per cent from 35 per cent; (iii) an increase in TGI's allowed ROE, effective July 1, 2009, to 9.50 per cent from 8.47 per cent; and (iv) an increase in the allowed ROE to 10.00 per cent, effective July 1, 2009, from 9.17 per cent for each of TGVI and TGWI. 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 continued use of a PBR mechanism after the expiry, on December 31, 2009, of TGI's previous PBR agreement. The approved mid-year rate base at TGI is approximately $2,540 million for 2010 and $2,634 million for 2011, and the approved mid-year rate base at TGVI is approximately $555 million for 2010 and $729 million for 2011. The overall impact on customer rates, including the effect of changes in the commodity and/or mid-stream rates for natural gas and/or propane, effective January 1, 2010, was: (i) an increase of approximately 10 per cent for residential customers in the Lower Mainland, Fraser Valley, Interior, North and the Kootenays; (ii) an increase of approximately 16 per cent for residential customers in Revelstoke; (iii) a decrease of approximately 12 per cent for customers in Whistler; and (iv) an increase of approximately 8 per cent for customers in Fort Nelson. Customer rates for TGVI's sales customers will remain unchanged for the two-year period beginning January 1, 2010, as provided in the BCUC-approved NSA for TGVI. • In June 2009, TGI filed an application with the BCUC requesting the in-sourcing of core elements of its customer care services and implementation of a new customer information system. Two new call centres and the customer information system are expected to be in place effective January 2012 at a total expected project cost of approximately $116 million, including deferral of certain operating and maintenance expenses. The application was approved in February 2010, upon the Company accepting a cost risk-sharing condition, whereby the Company would share equally with customers any costs or savings outside a band of plus or minus 10 per cent of the approved total project cost.
FortisBC	• In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application, resulting in a general customer rate increase of 4.6 per cent, effective January 1, 2009. The customer rate increase was primarily the result of the Company's ongoing investment in electrical infrastructure and increasing power purchase prices driven by customer growth and increased electricity demand. Rates for 2009 reflected an allowed ROE of 8.87 per cent as a result of the application of the ROE automatic adjustment formula. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the consumer price index ("CPI") for British Columbia minus a productivity improvement factor ("PIF") of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess is to be added to the PIF, which effectively caps the CPI at 3 per cent.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisBC (cont'd)	• In February 2009, the BCUC issued its decision on FortisBC's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million for 2010. • In August 2009, FortisBC applied for and received BCUC approval for a 2.2 per cent increase in customer rates, effective September 1, 2009. The increase was due to higher power purchase costs being charged to the Company by BC Hydro. • 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 per cent, effective January 1, 2010. The rate increase was primarily the result of the Company's ongoing investment in infrastructure, increasing power supply costs and the higher cost of capital. FortisBC's allowed ROE has increased to 9.90 per cent, effective January 1, 2010, from 8.87 per cent in 2009 as a result of the BCUC decision to increase the allowed ROE of TGI, the benchmark utility in British Columbia. The BCUC-approved NSA assumes a mid-year rate base of approximately $975 million for 2010.
FortisAlberta	• In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result was a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase was slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA, due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflected the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. • In June 2009, FortisAlberta filed a comprehensive two-year Distribution Revenue Requirements Application for 2010 and 2011. The application forecasts a mid-year rate base of approximately $1,538 million for 2010 and $1,724 million for 2011. The expected impact on the distribution component of customer rates is an average increase of 13.3 per cent for 2010 and 14.9 per cent for 2011, before considering the impact of the increase in the allowed ROE and the deemed equity component of the total capital structure, as per the AUC Generic Cost of Capital Decision. The incremental effect of the final approved 2009 ROE and capital structure, as described below, is expected to be collected in customer electricity rates in 2010. New customer electricity rates to be established for 2010 will reflect an allowed ROE of 9.00 per cent on a deemed equity component of the total capital structure of 41 per cent. FortisAlberta anticipates a regulatory decision by the AUC to be received in spring 2010 with final customer electricity rates anticipated to take effect in late 2010 or early 2011. An interim approval of customer electricity rates by the AUC has resulted in an overall 7.5 per cent average increase in base customer distribution electricity rates at FortisAlberta, effective January 1, 2010. • In November 2009, the AUC issued its decision on the 2009 Generic Cost of Capital Proceeding, establishing a generic allowed ROE for all Alberta utilities it regulates of 9.00 per cent for each of 2009 and 2010. The allowed ROE of 9.00 per cent is up from 8.61 per cent that the former ROE automatic adjustment formula would have provided for FortisAlberta in 2009. The ROE automatic adjustment formula will no longer apply until reviewed further by the AUC. The AUC also increased the deemed equity component of FortisAlberta's total capital structure to 41 per cent from 37 per cent, effective January 1, 2009. Two hundred basis points of the increase in the equity component of the capital structure reflected the effects of FortisAlberta having become a non-taxable utility for rate-setting purposes. The AUC also ordered that the generic allowed ROE for Alberta utilities that it regulates, including FortisAlberta, be established on an interim basis for 2011 at 9.00 per cent. The establishment of an interim ROE level was chosen because the AUC was not prepared to reimpose an adjustment formula without the opportunity to assess changes in the capital markets and to reconsider the types of factors that should be built into a formula.
Newfoundland Power	• In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to construction and capital maintenance of the electricity system. During the third quarter of 2009, Newfoundland Power filed supplemental applications to its 2009 Capital Budget Application, requesting an additional approximate $2 million in capital spending, which were approved by the PUB. • The Company's allowed ROE of 8.95 per cent for 2009 remained unchanged from 2008 and, consequently, did not impact customer electricity rates for 2009. • Effective July 1, 2009, the PUB approved an overall average decrease in customer electricity rates of approximately 6.6 per cent, reflecting the flow through to customers, by operation of the Rate Stabilization Account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The decrease in customer electricity rates had no impact on Newfoundland Power's earnings in 2009. • In November 2009, the Company's 2010 Capital Budget Application totalling approximately $65 million was approved by the PUB. • In December 2009, the PUB issued a decision on Newfoundland Power's 2010 General Rate Application, resulting in an overall average increase in basic customer electricity rates of approximately 3.5 per cent, effective January 1, 2010, including the impact of an increase in the allowed ROE to 9.00 per cent from 8.95 per cent in 2009, as set by the PUB for 2010. The PUB decision assumes a mid-year rate base of approximately $869 million for 2010. The PUB also ordered that Newfoundland Power's allowed ROE for each of 2011 and 2012 be determined using the ROE automatic adjustment formula. The ROE automatic adjustment formula is subject to a review by the PUB in the first quarter of 2010.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Maritime Electric	• In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which resulted in an increase in the base amount of energy-related costs being expensed and collected from customers and recorded in revenue through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kilowatt hour ("kWh") to 7.7 cents per kWh resulted in a decrease in the amount of energy costs collected from customers through the operation of the Energy Cost Adjustment Mechanism ("ECAM"). Additionally, IRAC approved the deferral of the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer electricity rates for 2009 was an increase of 5.3 per cent based on average consumption of 650 kWh per month. • In September 2009, NB Power announced that the refurbishment of Point Lepreau was behind schedule with the target date for electricity to be generated again delayed until early 2011. The Point Lepreau reactor was originally scheduled to restart October 1, 2009. • In October 2009, Maritime Electric received regulatory approval, as filed, of its 2010 Capital Budget Application totalling $22 million, before customer contributions. • In October 2009, Maritime Electric received regulatory approval of the extension of its energy purchase agreement with NB Power to December 31, 2010. The agreement, originally entered into in April 2008, was set to expire in September 2009 when Point Lepreau was to return to service. Delays in the refurbishment and resulting return to service date of Point Lepreau required an extension of the energy purchase agreement. • In January 2010, Maritime Electric filed an application with IRAC: (i) providing a report on the impact of the rebasing of the ECAM deferral account in 2009 and requesting an increase in the reference cost of energy in basic rates from 7.7 cents per kWh to 9.4 cents per kWh, effective April 1, 2010, and from 9.4 cents per kWh to 9.6 cents per kWh, effective April 1, 2011; (ii) requesting that the replacement energy costs incurred during the refurbishment of Point Lepreau be amortized over a period of 25 years, representing the extended life of the unit; and (iii) requesting an allowed ROE of 9.75 per cent for both 2010 and 2011, unchanged from 2009.
FortisOntario	• In August 2009, the OEB issued its Rate Order for Fort Erie and Gananoque, approving final distribution rate increases using 2009 as a forward test year, effective May 1, 2009, of 5.1 per cent and 11.7 per cent, respectively, with impact on customer billings commencing September 1, 2009. Foregone revenue from May 1, 2009 through August 31, 2009 will be recovered from customers through a rate rider in effect from September 1, 2009 through April 30, 2010. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity, approved an allowed ROE of 8.01 per cent for 2009 and approved all forecast capital expenditures and significantly all forecast operating expenses, as filed. The approved rate increases were primarily driven by the impact of distribution system upgrades. • In September and October 2009, the OEB held a stakeholder conference to determine whether current economic and financial market conditions warranted an adjustment to any cost of capital. In December 2009, the OEB issued its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities.* Based on current economic indicators, a preliminary allowed ROE has been set at 9.75 per cent for utilities in Ontario regulated by the OEB. The ROE formula has been refined to reduce sensitivity to changes in long-term Canada bond yields and includes an additional factor for utility bond spreads. The updated allowed ROE will come into effect for the setting of customer rates beginning in 2010 by way of a cost of service application. • In October and November 2009, FortisOntario filed 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, based on a deemed capital structure containing 40 per cent equity. In non-rebasing years, customer electricity rates are set using inflationary factors less an efficiency target under the OEB's Third-Generation IRM. • In October 2009, the OEB issued its Rate Order for Port Colborne, approving a final electricity rate increase using 2009 as a forward test year, effective May 1, 2009, of 8.4 per cent, with impact on customer billings commencing November 1, 2009. Foregone revenue from May 1, 2009 through October 31, 2009 will be recovered from customers through a rate rider in effect from November 1, 2009 through April 30, 2011. The Rate Order confirmed a deemed capital structure containing 43.3 per cent equity and approved an allowed ROE of 8.01 per cent for 2009. • FortisOntario expects to file a new electricity rate application for Algoma Power during the first half of 2010 for rates effective July 1, 2010, using 2010 as a forward test year and an allowed ROE of 9.75 per cent.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Belize Electricity	• In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application, which rejected most of the recommendations of a PUC-appointed Independent Expert engaged to review the PUC's Initial Decision on Belize Electricity's 2008/2009 Rate Application and failed to increase the overall average electricity rate, as requested in the application. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. As a direct result of the June 2008 Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. The Final Decision does not affect the Corporation's hydroelectric generation operations conducted in BECOL. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactively effective September 1, 2008, allows for the recovery from, or refund to, customers of the actual cost of power that varies from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • In April 2009, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2009 to June 30, 2010 (the "2009/2010 Rate Application") proposing a 6 per cent decrease in the average electricity rate, as well as a reversal of the BZ$36 million charge described above. The PUC has not accepted the 2009/2010 Rate Application on the grounds that an Annual Tariff Review Proceeding is not in effect. • Changes made in electricity legislation by the Government of Belize and the PUC, and the PUC's June 2008 Final Decision and the Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely final outcome of the proceedings is indeterminable at this time. The Supreme Court of Belize issued an injunction against the Amendment until Belize Electricity's appeal of the June 2008 Final Decision has been heard in court. The court appeal of the June 2008 Final Decision was called in early October 2009 but, after considering some preliminary matters, the trial judge postponed the case for a date to be determined. In addition, Belize Electricity's appeal of the Supreme Court of Belize's previous decision to uphold certain changes made in electricity legislation by the Government of Belize and the PUC was dismissed in June 2009. • In June 2009, the Government of Belize issued a statutory instrument purporting to declare providers of electricity generation and water services, including BECOL, as public utility providers within the meaning of the *Public Utilities Commission Act* as of May 1, 2009. Fortis continues to assess the statutory instrument and its impact on previously negotiated and PUC-approved power purchase agreements.
Caribbean Utilities	• In March 2009, the ERA approved the Company's 2009 Capital Investment Plan ("CIP") of US$48 million. • In April 2009, Caribbean Utilities submitted its bid to install 16 MW of generation in May 2012 and another 16 MW of generation in May 2013. There was one other bidder for the 32 MW of generation. In September 2009, based on economic conditions and revised medium-term future load growth projections by Caribbean Utilities, the ERA cancelled its 32 MW capacity-expansion solicitation. Caribbean Utilities and the ERA will continue to monitor growth indicators and revise forecasts as necessary. A new solicitation may occur at such time as there are indicators of a future need for additional capacity. • The ERA approved a 2.4 per cent increase in basic customer electricity rates, effective June 1, 2009, in accordance with Caribbean Utilities' T&D licence. • In February 2010, the ERA approved Caribbean Utilities' 2010–2014 CIP at US$98 million for non-generation expansion expenditures. The 2010–2014 CIP submitted by Caribbean Utilities to the ERA in October 2009 totalled US$157 million, which included approximately US$59 million for estimated costs associated with future generation expansion to be solicited.
Fortis Turks and Caicos	• In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2009 and December 31, 2008.

Significant Changes in the Consolidated Balance Sheets between December 31, 2009 and December 31, 2008

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	(86)	The decrease was primarily due to warmer temperatures, lower natural gas commodity prices at the Terasen Gas companies and lower fuel costs at Caribbean Utilities and Fortis Turks and Caicos.
Regulatory assets – current and long-term	621	The increase was primarily due to recording $560 million in regulatory assets as at December 31, 2009, associated with the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009. The remainder of the increase was mainly due to: (i) the deferral at the Terasen Gas companies of the change in the fair market value of the natural gas derivatives and of actual net mid-stream natural gas costs in excess of the amounts collected in customer rates in 2009; (ii) the deferral of Point Lepreau energy replacement costs at Maritime Electric; and (iii) the 2009 AESO charges deferral account at FortisAlberta. The increase was partially offset by the impact of the deferral of amounts collected in customer rates in excess of the actual commodity cost of natural gas at the Terasen Gas companies during 2009.
Inventories	(51)	The decrease was primarily associated with lower natural gas commodity prices.
Other assets	(56)	The decrease was driven by a $61 million reduction associated with the discontinuance of the consolidation method of accounting for the Corporation's interest in the Exploits Partnership, effective February 12, 2009, partially offset by higher accrued pension assets at Newfoundland Power, due to pension funding being in excess of pension expense for 2009. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.
Utility capital assets	546	The increase primarily related to $966 million invested in electricity and gas systems, partially offset by amortization, customer contributions and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets.
Accounts payable and accrued charges	(22)	The decrease was driven by lower amounts owing for purchased natural gas at the Terasen Gas companies, due to lower natural gas prices and volumes, partially offset by a $30 million increase associated with the change in the fair market value of the natural gas derivatives at the Terasen Gas companies.
Dividends payable	(44)	The decrease was due to the timing of the declaration of common share dividends.
Income taxes payable	(43)	The decrease was mainly due to the timing of income tax payments at the Terasen Gas companies and Newfoundland Power.
Regulatory liabilities – current and long-term	55	The increase was primarily due to recording $35 million in regulatory liabilities as at December 31, 2009, associated with the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009. Regulatory liabilities also increased due to the lower cost of fuel and purchased power at Belize Electricity during 2009 compared to amounts collected in customer rates during 2009 and the deferral of the margin impact of actual customer consumption exceeding forecast consumption during 2009 at the Terasen Gas companies. The increase was partially offset by the deferral of actual net mid-stream natural gas costs in excess of amounts collected in customer rates at the Terasen Gas companies during 2009.
Future income tax liabilities – current and long-term	524	The increase was primarily due to the recognition of future income taxes upon adoption of amended Section 3465, *Income Taxes*, effective January 1, 2009.

Significant Changes in the Consolidated Balance Sheets between December 31, 2009 and December 31, 2008 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion)	376	The increase was primarily due to the issuance of long-term debt, partially offset by a net $14 million repayment of committed credit facility borrowings and a $61 million decrease associated with the discontinuance of the consolidation method of accounting for the Corporation's interest in the Exploits Partnership, effective February 12, 2009; regularly scheduled debt repayments and debt maturities; and the impact of foreign exchange on the translation of foreign currency-denominated debt. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership. The issuance of long-term debt, primarily to repay committed credit facility borrowings, short-term borrowings and maturing debt, was comprised of a $100 million debenture offering by TGI, a $225 million debenture offerings by FortisAlberta, a $65 million bond offering by Newfoundland Power, a US$40 million note offering by Caribbean Utilities, a $105 million debenture offering by FortisBC and a $200 million debenture offering by Fortis. The net $14 million decrease in committed credit facility borrowings was driven by net repayments at FortisAlberta and Newfoundland Power, partially offset by net borrowings at the Corporation. The regularly scheduled debt repayments included the repayment of $60 million of maturing debt at TGI and $50 million of maturing debt at FortisBC.
Non-controlling interest	(22)	The decrease primarily related to the impact of foreign exchange on the translation of US dollar-denominated non-controlling interest amounts, combined with Fortis increasing its controlling ownership in Caribbean Utilities by 2.7 per cent in July 2009.
Shareholders' equity	147	The increase was mainly due to net earnings applicable to common shares for 2009, less common share dividends. The remainder of the increase related to the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans, partially offset by an increase in accumulated other comprehensive loss.

Liquidity and Capital Resources

The table below outlines the Corporation's sources and uses of cash in 2009 compared to 2008, followed by a discussion of the nature of the variances in cash flows year over year.

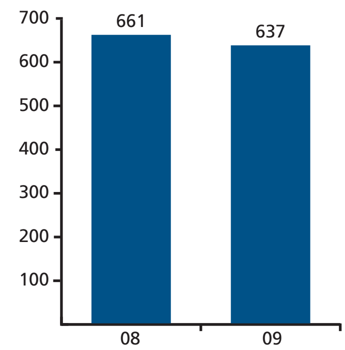
Summary of Cash Flows

Years Ended December 31

($ millions)	**2009**	2008	Variance
Cash, Beginning of Year	**66**	58	8
Cash Provided By (Used In)			
Operating Activities	**637**	661	(24)
Investing Activities	**(1,052)**	(852)	(200)
Financing Activities	**438**	196	242
Foreign Currency Impact on Cash Balances	**(4)**	3	(7)
Cash, End of Year	**85**	66	19

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2009 was $24 million lower than in the previous year. The decrease was mainly due to the timing of the declaration of common share dividends, the timing and an increase in the amount of corporate income taxes paid at Newfoundland Power and 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. The decrease was partially offset by favourable changes in the AESO charges deferral account at FortisAlberta.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2009 was $200 million higher than in the previous year. Investing activities in 2009, however, reflected the acquisition of Algoma Power for approximately $70 million, net of cash acquired, and the Holiday Inn Select Windsor for approximately $7 million. Investing activities in 2008 reflected the acquisition of the Sheraton Hotel Newfoundland for approximately $22 million. Excluding the impact of business acquisitions in 2009 and 2008, cash used in investing activities increased year over year due to higher gross capital expenditures and lower contributions in aid of construction.

Gross capital expenditures in 2009 were $1,024 million, $89 million higher than in 2008. The increase was driven by higher utility capital asset spending at FortisAlberta and the Terasen Gas companies.

Financing Activities: Cash provided by financing activities in 2009 was $242 million higher than in the previous year, mainly due to higher proceeds from long-term debt, lower repayments of long-term debt, and lower net repayments under committed credit facilities and short-term borrowings, partially offset by lower proceeds from common share and preference share issues.

Net short-term borrowings were $8 million for 2009 compared to net repayment of short-term borrowings of $69 million for 2008. The increase in cash provided by changes in short-term borrowings was driven by the Terasen Gas companies and Maritime Electric.

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 2009 compared to 2008 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2009**	2008	Variance
Terasen Gas Companies	**99**[(1)]	496[(2)(3)]	(397)
FortisAlberta	**222**[(4)(5)]	99[(6)]	123
FortisBC	**104**[(7)]	–	104
Newfoundland Power	**64**[(8)]	–	64
Maritime Electric	**–**	60[(9)]	(60)
Caribbean Utilities	**43**[(10)]	–	43
Corporate – Fortis	**197**[(11)]	–	197
Other	**–**	7	(7)
Total	**729**	662	67

(1) 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.

(2) Issued May 2008, 30-year $250 million 5.80% unsecured debentures by TGI. The net proceeds were primarily used to repay maturing $188 million 6.20% debentures and short-term borrowings.

(3) Issued February 2008, 30-year $250 million 6.05% unsecured debentures by TGVI. The net proceeds were used to repay committed credit facility borrowings.

(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 April 2008, 30-year $100 million 5.85% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings.

(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 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 April 2008, 30-year $60 million 6.05% secured first mortgage bonds. The proceeds were used to repay short-term borrowings.

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

(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)	**2009**	2008	Variance
Terasen Gas Companies	**(62)**	(193)	131
FortisBC	**(55)**	–	(55)
Newfoundland Power	**(5)**	(5)	–
Caribbean Utilities	**(16)**	(11)	(5)
Fortis Properties	**(24)**	(13)	(11)
Corporate – Terasen	**–**	(200)	200
Other	**(10)**	(9)	(1)
Total	**(172)**	(431)	259

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2009**	2008	Variance
Terasen Gas Companies	**5**	(261)	266
FortisAlberta	**(99)**	101	(200)
FortisBC	**4**	31	(27)
Newfoundland Power	**(18)**	(1)	(17)
Corporate	**94**	(179)	273
Total	**(14)**	(309)	295

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. During the third quarter of 2009, a net repayment of $144 million under the Corporation's committed credit facility was financed with partial proceeds from the issuance of $200 million unsecured debentures ($197 million net of costs). During the second quarter of 2008, a net repayment of $170 million under the Corporation's committed credit facility was financed with partial proceeds from the issuance of $230 million preference shares ($223 million net of costs).

Net proceeds associated with the issuance of common shares under the Corporation's share purchase and stock option plans in 2009 were $46 million compared to $21 million in 2008, reflecting the impact, effective March 1, 2009, of the Corporation's Dividend Reinvestment and Share Purchase Plan. The Dividend Reinvestment and Share Purchase Plan provides participating common shareholders a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008, and for general corporate purposes.

Common share dividends were $133 million for 2009, down $29 million from 2008. The decrease was a result of the timing of the declaration of common share dividends, partially offset by a higher number of common shares outstanding during 2009, primarily as a result of the public issuance of 11.7 million common shares in December 2008. The dividend declared per common share was $0.78 in 2009 compared to $1.01 in 2008.

Preference share dividends increased $4 million year over year as a result of the dividends associated with the 9.2 million First Preference Shares, Series G that were issued during the second quarter of 2008.

Contractual Obligations: Consolidated contractual obligations of Fortis for periods over the next five years and thereafter, as at December 31, 2009, are outlined in the following table.

Contractual Obligations

As at December 31, 2009 ($ 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)	**5,502**	222	312	797	4,171
Brilliant Terminal Station(2)	**62**	3	5	5	49
Gas purchase contract obligations(3)	**746**	387	193	166	–
Power purchase obligations					
FortisBC(4)	**2,921**	42	83	78	2,718
FortisOntario(5)	**509**	46	95	99	269
Maritime Electric(6)	**66**	47	2	2	15
Belize Electricity(7)	**327**	26	65	69	167
Capital cost(8)	**383**	15	40	42	286
Joint-use asset and shared service agreements(9)	**62**	4	6	6	46
Office lease – FortisBC(10)	**19**	1	4	3	11
Operating lease obligations(11)	**147**	17	31	27	72
Equipment purchase – Fortis Turks and Caicos(12)	**12**	8	4	–	–
Other	**30**	12	12	5	1
Total	**10,786**	830	852	1,299	7,805

(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 is expected to make a $4 million repayment on the loans in 2010 (2009 – $8 million). As at December 31, 2009, the outstanding balance of the repayable government loans was $53 million, with $4 million classified as current portion of long-term debt. Repayments of the government loans beyond 2010 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms. TGVI, however, estimates making payments under the loans of $20 million in 2012, $14 million over 2013 and 2014 and $15 million thereafter.

(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, 2009.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), as well as the power purchase agreement with BC Hydro. 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 power purchase agreement 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.

(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. The take-or-pay contract with NB Power includes, among other things, replacement energy and capacity for Point Lepreau during its refurbishment outage, and the contract expires in December 2010. 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 power purchase agreement, 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 power purchase agreements 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.

In October 2009, the CFE of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010.

(8) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from Point Lepreau 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.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of 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 contract, the calculation of future payments after 2014 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, 2005 and are subject to extension based on mutually agreeable terms.

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

(12) Fortis Turks and Caicos has entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for delivery in mid-2010 and early 2011.

Other Contractual Obligations: Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The contract is for three years terminating in April 2010, with 9 million imperial gallons required to be purchased during 2010. 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.

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.

Pension Funding: The fair value of the Corporation's consolidated defined benefit pension plan assets increased approximately 14 per cent, or $82 million, during 2009, commensurate with the recovery in the capital markets. This increase compares to a decrease of approximately 14 per cent, or $95 million, during 2008 mainly due to unfavourable market conditions during that year. Details of the nature of the changes in the fair value of the plan assets are disclosed in Note 20 to the Corporation's 2009 Consolidated Financial Statements.

Market-driven changes impacting the performance of pension plan assets and the discount rate may result in material changes in future pension funding requirements and/or net pension cost. The decline in fair value of the pension plan assets during 2008 did not materially affect the Corporation's consolidated defined benefit plan funding contributions for 2009.

Consolidated defined benefit pension funding contributions, including current service, solvency and special funding amounts, are expected to be $20 million in 2010, $8 million in 2011, $4 million in 2012 and $3 million in 2013. Fortis expects defined benefit pension plan funding contributions to be sourced primarily from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities. The contributions above, however, 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 as follows for the larger defined benefit pension plans:

December 31, 2009	Terasen (covering non-unionized employees)
December 31, 2010	Terasen (covering unionized employees) and FortisBC
December 31, 2011	Newfoundland Power

Consolidated defined benefit pension funding contributions for 2009 were not materially impacted by the outcome of the actuarial valuations as at December 31, 2008 for defined benefit pension plans at Newfoundland Power and the Corporation, and as at December 31, 2007 for one of the defined benefit pension plans at Terasen, which were completed during the first quarter of 2009.

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. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent 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, 2009 compared to December 31, 2008 is presented in the following table.

Capital Structure

As at December 31	**2009**		2008	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash)(1)	**5,830**	**60.2**	5,468	59.5
Preference shares(2)	**667**	**6.9**	667	7.3
Common shareholders' equity	**3,193**	**32.9**	3,046	33.2
Total	**9,690**	**100.0**	9,181	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

The slight change in the capital structure was driven by higher debt levels, primarily in support of infrastructure investment, and increased accumulated other comprehensive loss, driven by unfavourable foreign exchange, partially offset by net earnings applicable to common shares, net of common share dividends, of $129 million and increased common shares outstanding reflecting the impact of the Corporation's enhanced Dividend Reinvestment and Share Purchase Plan.

The Corporation's credit ratings are as follows:

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

In September 2009, S&P confirmed its credit rating for Fortis at A– (stable outlook). The credit ratings reflect the diversity of the operations of Fortis, 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 continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. 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 2009, approximately $91 million in maintenance and repairs was expensed compared to approximately $90 million during 2008.

Gross consolidated capital expenditures for the year ended December 31, 2009 were more than $1 billion. A breakdown of gross capital expenditures by segment and asset category for 2009 is provided in the following table.

Gross Capital Expenditures[(1)]

Year Ended December 31, 2009

($ 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	10	3	**32**	**45**	**14**	**–**	**91**
Transmission	118	–	49	5	8	**180**	**12**	**–**	**–**	**192**
Distribution	97	269	32	52	32	**482**	**27**	**–**	**–**	**509**
Facilities, equipment, vehicles and other	15	128	10	3	2	**158**	**6**	**3**	**26**	**193**
Information technology	16	10	5	4	1	**36**	**2**	**1**	**–**	**39**
Total	246	407	115	74	46	**888**	**92**	**18**	**26**	**1,024**

(1) Relates to utility capital assets, income producing properties and intangible assets and includes capital expenditures associated with assets under construction. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures were permissible in rate base in 2009. Excludes capitalized non-cash equity component of the Allowance for Funds Used During Construction ("AFUDC").

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

(3) Includes non-regulated utility and Corporate capital expenditures

Actual gross consolidated capital expenditures for 2009 were comparable to those forecasted and disclosed in the MD&A for the year ended December 31, 2008. An increase in capital spending at FortisAlberta associated with higher than anticipated customer-driven capital expenditures, including new customer connections, and the inclusion of AESO transmission capital expenditures in total capital expenditures was offset mainly by: (i) a shift from 2009 to 2010 of some capital spending related to the Vaca hydroelectric generating project and certain projects at the Terasen Gas companies and FortisBC; (ii) lower than forecasted capital spending at non-regulated TES; and (iii) lower spending at FortisBC associated with the Okanagan Transmission Reinforcement Project.

Gross consolidated capital expenditures for 2010 are expected to be approximately $1.1 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 capital expenditures by segment and asset category for 2010 is provided in the following table.

Forecast Gross Capital Expenditures[(1)]

Year Ending 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	–	–	19	6	3	**28**	**28**	**16**	**–**	**72**
Transmission	146	–	92	7	3	**248**	**10**	**–**	**–**	**258**
Distribution	100	212	38	47	37	**434**	**31**	**–**	**–**	**465**
Facilities, equipment, vehicles and other	64	139	15	4	2	**224**	**12**	**–**	**26**	**262**
Information technology	17	12	4	5	2	**40**	**1**	**–**	**–**	**41**
Total	327	363	168	69	47	**974**	**82**	**16**	**26**	**1,098**

(1) Relates to utility capital assets, income producing properties and intangible assets and includes forecast capital expenditures associated with assets under construction. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base. Excludes forecast capitalized non-cash equity component of AFUDC.

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

(3) Includes forecast non-regulated utility and Corporate capital expenditures

The percentage breakdown of 2009 actual and 2010 forecast gross capital expenditures among growth, sustaining and other is as follows:

Gross Capital Expenditures

Year Ended December 31 (%)	Actual 2009	Forecast 2010
Growth	**47**	41
Sustaining(1)	**30**	32
Other(2)	**23**	27
Total	**100**	100

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

2) Relates to facilities, equipment, vehicles, information technology systems and other assets, including Automated Meter Infrastructure ("AMI") and the in-house customer care enhancement project at TGI

Significant capital projects for 2009 and 2010 are summarized in the table below.

Significant Capital Projects(1)

($ millions) Company	Nature of project	Pre-2009	Actual 2009	Forecast 2010	Forecast costs to complete after 2010	Year of expected completion
Terasen Gas Companies	LNG storage facility – Vancouver Island	47	**71**	66	27	2011
	Squamish-to-Whistler pipeline lateral and system conversion	39	**15**	2	–	2009
	Customer Care Enhancement Project	–	**1**	31	84	2012
	Fraser River South Bank South Arm Rehabilitation Project	1	**7**	19	–	2010
FortisAlberta	AMI technology	24	**58**	64	9	2011
FortisBC	Okanagan Transmission Reinforcement Project	7	**22**	63	18	2011
	Transmission Projects	65	**17**	14	20	2013
	Generation asset Upgrade and Life-Extension Program	17	**13**	15	20	2012
Caribbean Utilities	New 16-MW diesel-powered generating unit	8	**22**	–	–	2009
Non-Regulated – Fortis Generation	19-MW Vaca hydroelectric generating facility in Belize	32	**13**	14	–	2010
Fortis Properties	Expansion of Holiday Inn Express Kelowna	1	**9**	2	–	2010

(1) Relates to property, plant and equipment expenditures in addition to capitalized interest and non-cash equity components of AFUDC

In April 2008, TGVI received BCUC approval to proceed with the engineering, procurement and construction of an LNG storage facility. Construction commenced in 2008 and continued during 2009 with the facility expected to be in service by late 2011. The total capital cost of this project is estimated at approximately $211 million.

TGVI's construction of the 50-kilometre Squamish-to-Whistler natural gas pipeline lateral was completed during spring 2009, with conversion of Whistler customer appliances completed in August 2009. The total project cost of the pipeline construction and conversion of the appliances is estimated at approximately $56 million, $8 million higher than the amount previously approved by the BCUC for this project. A provision for approximately $5 million after-tax related to the additional costs associated with the conversion of the appliances has been expensed to earnings in the fourth quarter of 2009. However, applications have been filed with the BCUC requesting inclusion in rate base of the total additional costs. The pipeline lateral and appliance conversion were required as part of the overall conversion of TGWI's propane distribution system to a natural gas distribution system.

In June 2009, TGI filed an application with the BCUC requesting the in-sourcing of core elements of its customer care service and for implementation of a new customer information system. Two new call centres and the customer information system are expected to be in place effective January 2012 at an expected project cost of approximately $116 million, including deferral of certain operating and maintenance expenses. The application was approved in February 2010, upon the Company accepting a cost risk-sharing condition, whereby the Company would share equally with customers any additional costs or savings outside a band of plus or minus 10 per cent of the approved total project cost.

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. The project is estimated to cost approximately $27 million and is expected to be in service in 2010.

FortisAlberta continued the replacement of conventional customer meters with new AMI technology during 2009. In response to the direction of the Alberta Department of Energy on AMI capabilities, FortisAlberta has adjusted the scope of its planned AMI program, which is now expected to cost approximately $155 million, up from $124 million as disclosed in the MD&A for the year ended December 31, 2008. Additional capital costs may be incurred under this project, pending clarification of meter data reporting requirements by the appropriate government agencies. The final project cost is subject to regulatory approval.

FortisBC began construction on the approximate $110 million Okanagan Transmission Reinforcement Project in July 2009, with completion expected in mid-2011. The total forecast cost of the project is down from the original estimate of $141 million as disclosed in the MD&A for the year ended December 31, 2008. The decrease in cost is mainly due to lower forecasted labour, equipment and commodity costs. The project relates to upgrading the existing overhead transmission lines from 161 kilovolts ("kV") to 230 kV between Penticton and Oliver and building a new 230-kV terminal in the Oliver area.

During 2009 several major transmission projects were completed at FortisBC. The Company forecasts an additional $34 million in capital spending related to major transmission growth-related projects from 2010 through 2013, of which $20 million is subject to regulatory approval.

Since 1998, a major life extension of hydroelectric generating facilities has been underway at FortisBC, involving the rebuilding of 11 of the 15 hydroelectric generating units in the utility's four generating plants. Eight units have been rebuilt to date and the program is scheduled for completion in 2012. The upgrades will improve efficiency, safety and environmental stewardship and will maintain the overall reliability of the plants. FortisBC forecasts approximately $35 million in additional BCUC-approved capital spending related to this initiative from 2010 through 2012.

In 2009, Caribbean Utilities commissioned a 16-MW diesel-powered generating unit for a total project cost of approximately $30 million.

The US$53 million Vaca hydroelectric generating facility will be commissioned in March 2010. The facility is expected to increase average annual energy production from the Macal River in Belize by approximately 80 GWh to 240 GWh.

The seven-storey, 70-room, 4,500-square feet of meeting room space expansion to the Holiday Inn Express Kelowna was completed in February 2010 at a total cost of $12 million.

Over the five-year period 2010 through 2014, consolidated gross capital expenditures are expected to approach $5 billion. Approximately 70 per cent of the capital spending is expected to be incurred at the Regulated Electric Utilities, driven by FortisAlberta and FortisBC. Approximately 27 per cent of the capital spending is expected to be incurred at the Regulated Gas Utilities and 3 per cent is expected to be incurred at the non-regulated operations. 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 Corporation does not expect any significant decrease in subsidiary operating cash flows in 2010 as a result of any continuation of the economic downturn. The subsidiaries expect to be able to source the cash required to fund their 2010 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately $220 million in 2010 and to average approximately $270 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As 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 $7 million (BZ$12 million) as at December 31, 2009. The Company has informed the lenders of the defaults and has requested appropriate waivers.

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 $59 million as at December 31, 2009 (December 31, 2008 – $61 million). The lenders of the term loan have not demanded accelerated repayment. A further discussion of the Exploits Partnership is provided in 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, 2009 and are expected to remain compliant in 2010.

Credit Facilities: As at December 31, 2009, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.4 billion was unused, including $476 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 per cent of these facilities.

Approximately $2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013.

The cost of renewed and extended credit facilities may increase 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 2010, as the majority of the total committed credit facilities have maturities between 2011 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, 2009**	Total as at December 31, 2008
Total credit facilities	645	1,495	13	**2,153**	2,228
Credit facilities utilized:					
Short-term borrowings	–	(409)	(6)	**(415)**	(410)
Long-term debt (including current portion)	(125)	(83)	–	**(208)**	(224)
Letters of credit outstanding	(1)	(98)	(1)	**(100)**	(104)
Credit facilities unused	519	905	6	**1,430**	1,490

At December 31, 2009 and 2008, 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, 2008 to December 31, 2009 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2009 are detailed in Note 26 to the 2009 Consolidated Financial Statements.

Corporate and Other

In May 2009, Terasen entered into a $30 million unsecured committed revolving credit facility maturing in May 2011, to replace its $100 million committed revolving credit facility that matured in May 2009. The terms of the new credit facility are substantially the same as those of the credit facility it replaced.

Regulated Utilities

In April 2009, FortisBC amended its $150 million unsecured committed revolving credit facility, including extending the maturity date of the $50 million portion of the facility to May 2012 from May 2011 and extending the maturity date of the $100 million portion of the facility to May 2010 from May 2009.

FortisBC expects to have its $100 million 364-day committed revolving credit facility, due to mature in May 2010, extended for a further 364 days.

Maritime Electric expects to have its $50 million 364-day committed revolving credit facility, due to mature in March 2010, extended for a further 364 days.

Off-Balance Sheet Arrangements

As at December 31, 2009, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

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

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to 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 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2009 (2008 – 93 per cent), while approximately 88 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2009 (2008 – 83 per cent). 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 cost of service. 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 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 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.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision related to Belize Electricity's 2008/2009 Rate Application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Although all of the Corporation's regulated utilities currently operate under cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as ROE automatic adjustment formulas, are also being employed to varying degrees. A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section of this MD&A.

TGI and FortisBC are regulated by the BCUC and have, from time to time, used PBR mechanisms. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. The current PBR mechanism at FortisBC extends through 2011. 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 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 PBR mechanism after December 2009. Under the 2010 and 2011 rate settlement agreements reached at both TGI and TGVI, certain cost of service variances are subject to deferral account treatment and the balances are at the respective company's risk.

Additional information on the PBR mechanisms at TGI and FortisBC, and the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, is provided in 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, or fatigue cracks in, 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 comprehensive 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 transmission and distribution 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, to a lesser extent, 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. See 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 cost of service 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. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the utilities.

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 of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. 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 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 to 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 9 per cent per annum over the next five years. Approximately 56 per cent of Fortis Properties' operating income was derived from hotel investments in 2009 (2008 – 57 per cent). Same-hotel revenue declined at Fortis Properties' Hospitality Division in 2009 from 2008 and organic revenue growth will continue to be challenged in 2010 as a result of the economic downturn and its impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent 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 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 results of operations and the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by 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, the Corporation's corporate investment-grade credit ratings by S&P were confirmed and maintained during the third quarter of 2009. During 2009, the only changes in credit ratings for the Corporation's currently rated utilities were for Newfoundland Power, TGI and Caribbean Utilities. In August 2009, Moody's upgraded the credit rating of Newfoundland Power's first mortgage bonds from Baa1 to A2 and of TGI's secured debentures from A2 to A1. In November 2009, S&P changed the outlook on Caribbean Utilities' issuer credit rating from A(stable) to A(negative) as a result of pressures facing the Cayman Islands economy and concern that it could create a more difficult operating environment for Caribbean Utilities in the next few years. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

Despite volatility in the global capital markets, the Corporation and its utilities have been successful at raising long-term capital at reasonable rates. However, continued volatility in the global capital markets may increase the cost, and affect the timing, of 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 renewed and extended credit facilities may also increase going forward; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2010 as the majority of the total credit facilities have maturities between 2011 and 2013. As the Corporation's utilities are regulated under cost of service, any 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.

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 26 to the 2009 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. Most of the annual earnings of the Terasen Gas companies are generated 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. 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. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks 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 the Company 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 event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

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 currently 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 basic 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. 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 future 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 must be 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 recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded 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 qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, 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, 2009, the Corporation's corporately held US$390 million (December 31, 2008 – US$403 million) long-term debt had been designated as a hedge of a 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 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. As at December 31, 2009, the Corporation had approximately US$174 million (December 31, 2008 – US$119 million) in foreign net investments remaining to be hedged.

It is estimated that a 5 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.05, as at December 31, 2009, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2010.

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 the general level of long-term interest rates. The allowed rates of return are set either directly through automatic adjustment formulas or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. The ROE automatic adjustment formulas 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. Regulatory decisions received in 2009 have reduced the risk of further decreases in allowed ROEs for certain of the Corporation's utilities and other utilities in Canada. In December 2009, the BCUC issued a decision increasing the allowed ROEs at TGI and FortisBC to 9.50 per cent and 9.90 per cent, respectively. The BCUC also determined that the previous ROE automatic adjustment formula 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 decision on the 2009 Generic Cost of Capital Proceeding. The decision increased the allowed ROE of utilities in Alberta that it regulates, including FortisAlberta, to 9.00 per cent and discontinued the use of the ROE automatic adjustment formula until reviewed further by the AUC. In December 2009, the OEB issued a report reviewing cost of capital for utilities in Ontario. The OEB increased the allowed ROE for utilities in Ontario that it regulates, including FortisOntario, to 9.75 per cent and refined the ROE automatic adjustment formula to reduce sensitivity to changes in long-term Canada bond yields and included an additional factor for utility bond spreads. The National Energy Board ("NEB"), an independent federal agency that regulates several parts of Canada's energy industry, issued a decision in 2009 increasing the regulated total cost of capital of Trans Quebec & Maritimes Inc. ("TQM"), a Canadian regulated natural gas pipeline utility, which effectively established an approximate 100 basis point increase in TQM's allowed ROE for 2008 to 9.70 per cent on a 40 per cent equity ratio. The increase in the total cost of capital and allowed ROE was the result of a change in methodology, which now takes into account financial market information that considers, among other things, changes that have impacted financial markets and economic conditions. In October 2009, the NEB also issued a decision stating that its 1994 multi-pipeline rate of return on equity formula, used to determine the cost of capital for regulated pipeline companies, is no longer in effect, as there is doubt as to the ongoing correctness of using this formula. Instead, cost of capital will be determined by negotiations between the pipelines and their shippers or by the NEB.

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 described in the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2009, approximately 81 per cent 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, 2009.

Total Debt

As at December 31, 2009	*($ millions)*	*(%)*
Short-term borrowings	**415**	**7.0**
Utilized variable-rate credit facilities classified as long-term	**208**	**3.5**
Variable-rate long-term debt and capital lease obligations (including current portion)	**16**	**0.3**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**5,276**	**89.2**
Total	**5,915**	**100.0**

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps and the measurement and disclosure of the fair value of long-term debt. The impact of a material change in interest rates on the fair value measurement of the interest rate swap outstanding, as at December 31, 2009, is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swap and its near-term maturity.

The fair value of the interest rate swap and the Corporation's consolidated long-term debt, as at December 31, 2009, 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 2009 financial results, is disclosed in Note 26 to the 2009 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. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to events in the capital markets over the past year, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. The Terasen Gas companies did not experience any counterparty defaults in 2009 and are not expecting any counterparties to fail to meet their obligations. As events over the past year have indicated, however, the credit quality of counterparties can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly 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. See also the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since electricity prices in British Columbia continue to be set based on the historical average cost of production, rather than on market forces, they have remained artificially low compared to market-priced electricity. As a result, the price of electricity for residential customers in British Columbia is now only marginally higher than for natural gas. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for 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 the cost of service of the Terasen Gas companies in rates charged to customers. See also the "Business Risk Management – Risks Related to TGVI" and "Business Risk Management – Government of British Columbia's Energy Plan" sections of this MD&A.

Natural Gas 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.

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; however, only 60 per cent 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. A discussion of the critical accounting estimates associated with defined benefit pension plans is provided in 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 2 to the 2009 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. This may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

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

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements, the accrued benefit asset, 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 and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenue from the Government of British Columbia that currently covers approximately 20 per cent of the cost of service. 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 any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a reduction of rate base, will be required to be fully repaid. As at December 31, 2009, the balance outstanding under these loans was $53 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a natural progression from the previous plan with consistent principles and a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming, including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia legislature's adoption of the *Utilities Commission Amendment Act, 2008.* In addition, the *Carbon Tax Act, 2008* provides for a consumption tax on carbon-based fuels, which affects the competitiveness of natural gas versus non-carbon-based energy sources. The Act, however, did not introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the related legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: 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 could potentially 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 may 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. During 2009, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. 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, 2009, there were no material environmental liabilities recorded in the Corporation's 2009 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.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. 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 situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling 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. 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 greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

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 its 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.

As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

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 economical. 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.

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 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.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices had related to its non-regulated energy sales in Ontario, where energy was sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely related to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating facility. FortisOntario's water entitlement on the Niagara River expired April 30, 2009 at the end of a 100-year term and, as a result, the Corporation's exposure to market price fluctuations in Ontario has been substantially reduced as earnings related to the Rankine facility have ceased after that date. During 2009, earnings' contribution associated with the Rankine facility was $3.5 million. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to International Financial Reporting Standards: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). IFRS will require increased financial statement disclosure and will result in differences in accounting policies between Canadian GAAP and IFRS. The Corporation continues to assess the impact on its future financial reporting of transitioning to IFRS. In July 2009, the IASB issued the Exposure Draft – *Rate-Regulated Activities* ("ED/2009/8") stating that regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities. Conversely, if an accounting standard for rate-regulated activities is not approved or if a standard is approved that is substantially different from that proposed, this could increase volatility in the earnings of the Corporation's regulated utilities. For further information, refer to the "Future Accounting Changes – Transition to IFRS" section of this MD&A.

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 will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada before 2015. If the jurisdictions are unable to establish these 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 can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax-free. In the event that the offshore earnings become taxable, earnings' contribution from Regulated Electric Utilities – Caribbean and BECOL will decrease.

On December 10, 2008, the Advisory Panel on Canada's System of International Taxation (the "Advisory Panel") provided its recommendations to the Minister of Finance of the Government of Canada in its final report, *Enhancing Canada's International Tax Advantage*. The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if TIEAs are not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

Many of the proposals related to foreign affiliate measures, first announced in February 2004, are still in draft form. In the 2009 federal budget documents, the Government of Canada stated that the remaining proposals will be re-evaluated in light of the recommendations of the Advisory Panel before a decision is made on whether and how to proceed with them. On December 18, 2009, the Department of Finance of the Government of Canada released draft legislation, regulations and explanatory notes concerning the foreign affiliate rules under the federal *Income Tax Act*. These measures implement many of the foreign affiliate proposals announced on February 27, 2004.

As of August 31, 2009, the Department of Finance of the Government of Canada reported that it had entered into TIEA negotiations with the Cayman Islands and the Turks and Caicos Islands in June 2009. If agreements can be negotiated, the earnings from Caribbean Utilities and Fortis Turks and Caicos could be repatriated to Canada tax-free. The Corporation is not aware if the Government of Canada has initiated similar negotiations with the Government of Belize.

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 are employed to 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 transmission and generation facilities, on lands that are subject to land claims by various First Nations. 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. In addition, 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 58 per cent 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.

FortisAlberta's current collective agreement with the United Utility Workers' Association of Canada will expire in December 2010.

The collective agreement governing Maritime Electric's unionized employees represented by the International Brotherhood of Electrical Workers ("IBEW"), Local 1432, expired in December 2008. In February 2010, a new collective agreement, which expires December 31, 2013, was ratified by the union.

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 Standards

The nature, and impact on Fortis, of adopting amended or new Canadian Institute of Chartered Accountants ("CICA") accounting standards affecting the accounting for rate-regulated operations, goodwill and intangible assets, and income taxes, effective January 1, 2009, are described in detail in Notes 2, 4, 9, 10 and 19 to the 2009 Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the increase, as at January 1, 2009, in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items; and (ii) the reclassification, as at December 31, 2008, of $264 million to intangible assets and related decreases of $262 million to utility capital assets, $1 million to income producing properties and $1 million to other assets, due to the reclassification of the net book value of land, transmission and water rights, computer software costs, franchise costs, customer contracts and other costs.

In 2009, the Corporation also adopted the new Emerging Issues Committee Abstract 173 ("EIC-173"), *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities.* EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. There was no material effect on the Corporation's 2009 Consolidated Financial Statements as a result of adopting EIC-173.

Effective December 31, 2009, the Corporation adopted amendments to the CICA Handbook Section 3862, *Financial Instruments – Disclosures*, by providing additional disclosures about the fair value measurement of financial instruments and enhanced liquidity risk disclosures in the consolidated financial statements. The amendments establish a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value and are described and disclosed in Notes 2 and 25 to the 2009 Consolidated Financial Statements.

During the first quarter of 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership, due to the Corporation no longer having control over the cash flows and operations of the Exploits Partnership. Refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.

Future Accounting Changes

Transition to IFRS

In October 2009, the Accounting Standards Board ("AcSB") issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011.

The Corporation's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported on the Corporation's opening IFRS balance sheet as at January 1, 2010 and amounts reported by the Corporation for the year ended December 31, 2010.

The Corporation is continuing to assess the financial reporting impacts of adopting IFRS in 2011. While the impact on future financial position and results of operations is not fully determinable at this time, proposals put forth by the IASB in its July 2009 Exposure Draft ED/2009/8, if adopted, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities.

The Corporation does anticipate a change in the manner in which it will measure and recognize the value of its income producing properties under IFRS and a significant increase in disclosure resulting from the adoption of IFRS. The Corporation is identifying and assessing the impact of this change in valuation and additional disclosure requirements, as well as implementing systems changes that will be necessary to compile the required disclosures. Independent expertise has been engaged to assist in the valuation process.

Differences between IFRS and Canadian GAAP, in addition to those referenced further under "Accounting Policy Impacts and Decisions", may continue to be identified based on further detailed analyses by the Corporation, the outcome of a final standard on accounting for rate-regulated activities and other changes in IFRS prior to the Corporation's conversion to IFRS in 2011.

IFRS Conversion Project: The Corporation commenced its IFRS Conversion Project in 2007 when it established a formal project governance structure, which includes the Audit Committee of Fortis, senior management and project teams from each of the subsidiaries of Fortis. Overall project governance, management and support are coordinated by Fortis. An independent external advisor has been engaged to assist in the IFRS Conversion Project. Project progress reports are provided to the Corporation's Audit Committee on a quarterly basis. The Corporation has also engaged its external auditors, Ernst & Young, LLP, to review accounting policy determinations as they are arrived at and agreed upon internally by the Corporation's project team.

The Corporation's IFRS Conversion Project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, was completed in the first half of 2008. The areas of accounting difference of highest potential impact to the Corporation, based on existing IFRS at the time, were identified to include rate-regulated accounting; property, plant and equipment; investment property; provisions and contingent liabilities; employee benefits; impairment of assets; income taxes; business combinations; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of International Financial Reporting Standards* ("IFRS 1").

Phase Two: Analysis and Development is substantially complete and has involved detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff training and audit committee orientation; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition; analysis of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

Phase Three: Implementation and Review has commenced and involves the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Corporation's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS into the Corporation's business processes; and audit committee approval of IFRS-compliant interim and annual financial statements for 2011.

Accounting for Rate-Regulated Activities under IFRS: IFRS does not currently provide specific guidance with respect to accounting for rate-regulated activities. However, in December 2008, the IASB initiated a project on accounting for rate-regulated activities and whether or not rate-regulated entities could recognize assets and liabilities as a result of rate regulation imposed by a regulatory body.

On July 23, 2009, the IASB issued a proposed standard on accounting for rate-regulated activities, ED/2009/8, together with a request for public comments by November 20, 2009. Approximately 150 comment letters, including a response by Fortis, were received by the IASB. The IASB's project schedule had indicated that a final standard on rate-regulated activities would be released in the second quarter of 2010. Commentary received on the ED/2009/8, and resulting activities now planned by the IASB, creates uncertainty as to if and when a final standard will be released. If a final standard is released, it may not be until late 2011.

Based on ED/2009/8 as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS, based on the measurement of their expected present value. Subject to finalizing a methodology for estimating expected present value, the ability to record regulatory assets and liabilities, as proposed, should reduce earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. Continued uncertainty as to the final outcome of ED/2009/8, and a final standard on accounting for rate-regulated activities under IFRS, has resulted in the Corporation being unable to reasonably estimate and conclude on the impact on the Corporation's future financial position and results of operations with respect to differences, if any, in accounting for rate-regulated activities under IFRS versus Canadian GAAP.

Regulators in the jurisdictions in which the Corporation maintains regulated utility operations have initiated, or are engaged in, consultative processes aimed at addressing issues related to the transition to IFRS. These regulators are also working to define regulatory accounting requirements and respective changes that may be required subsequent to January 1, 2011.

During the second quarter of 2009, the AUC issued Rule 026, which provides both a set of guiding principles and positions on the elements of IFRS that will be adopted for rate-making purposes. FortisAlberta and other utilities in Alberta regulated by the AUC collaborated closely with the AUC in the development of Rule 026. FortisAlberta has made a Rule 026 compliant rate application for 2010 and 2011. A decision by the AUC on FortisAlberta's application is pending.

TGI, FortisBC and other regulated utilities in British Columbia drafted a set of IFRS guidelines for use in regulatory applications being submitted by the utilities to the BCUC, including a fourth quarter 2009 addendum to these guidelines to address ED/2009/8.

TGI and TGVI filed applications with the BCUC for the purpose of setting customer rates for 2010 and 2011. As part of these applications, TGI and TGVI applied for changes in accounting policies that, subject to a final IFRS on rate-regulated activities and review by the external auditors, would be compliant with IFRS where possible. In the fourth quarter of 2009, TGI and TGVI received BCUC approval of NSAs for 2010 and 2011 customer rates. The NSAs include provisions that the 2010 impacts of IFRS be deferred for inclusion in customer rates in 2011.

Included in FortisBC's 2010 Revenue Requirements Application was a discussion of IFRS issues that FortisBC expects to encounter on transition, which are largely the result of the uncertainty surrounding a final IFRS standard on accounting for rate-regulated activities. The BCUC's decision with respect to FortisBC's application includes the recognition of several proposed IFRS deferral accounts. The disposition of these deferral accounts will be revisited in conjunction with FortisBC's 2011 Revenue Requirements Application. FortisBC will also continue to work with the BCUC to identify IFRS transitional issues and to suggest how these issues may be addressed.

Other regulated utility operations of Fortis, including Newfoundland Power, Maritime Electric and FortisOntario, continue to provide their respective regulator with regular updates in relation to their plans for transition to IFRS and the status of ED/2009/8.

Accounting Policy Impacts and Decisions: The Corporation has completed its initial assessment of the impacts of adopting IFRS based on the standards as they currently exist, and has identified the following as having the greatest potential to impact the Corporation's accounting policies, financial reporting and information systems requirements upon conversion to IFRS. Final conclusions cannot be reached at this time with respect to the Corporation's rate-regulated entities pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(a) Property, Plant and Equipment

IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist. For example, capitalization of directly attributable costs in accordance with IAS 16, *Property, Plant and Equipment* ("IAS 16") may require measurement of an item of property, plant and equipment upon initial recognition to include or exclude certain previously recognized amounts under Canadian GAAP. Specifically, there may be changes in accounting for:

i) the amount of capitalized overheads;
ii) the capitalization of major inspections that were previously expensed under Canadian GAAP;
iii) the capitalization of depreciation for which the future economic benefits of an asset are absorbed in the production of another asset; and
iv) the capitalization of borrowing costs in accordance with IAS 23, *Borrowing Costs.*

However, ED/2009/8 proposes that, in the case of qualifying rate-regulated entities, amounts approved by the regulator for inclusion in the cost of self-constructed property, plant and equipment for rate-making purposes shall also be included in the cost of these assets for financial reporting purposes, even if the entity would not otherwise be permitted to include these costs in the cost of its property, plant and equipment based on the application of IAS 16.

IAS 16 also requires an allocation of the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and the depreciation of each part separately. This method of allocating property, plant and equipment may result in an increase in the number of component parts that are recorded and depreciated separately and, as a result, may affect the calculation of depreciation expense.

Upon transition to IFRS, an entity has the elective option to reset the cost of its property, plant and equipment based on fair value in accordance with the provisions of IFRS 1, and to use either the cost model or the revaluation model to measure its property, plant and equipment subsequent to transition. Upon transition to IFRS on January 1, 2010, the Corporation currently intends to reset the cost of hotel properties owned by its non-regulated subsidiary, Fortis Properties, based on fair value and to use the cost model to measure all of Fortis Properties' property, plant and equipment subsequent to transition (excluding those assets to be reclassified as investment property under IFRS, as discussed below under "Investment Property").

ED/2009/8 proposes a new transitional exemption for qualifying rate-regulated entities that will allow them to use, as of the date of transition, the carrying amount of property, plant and equipment under Canadian GAAP as the deemed cost under IFRS. The Corporation's rate-regulated utilities will likely avail of this transitional exemption should it be approved by the IASB as proposed.

The final extent of the impact of applying IAS 16 by the Corporation's rate-regulated utilities, and elective options with respect to accounting for their property, plant and equipment upon transition to IFRS, cannot be made at this time pending further certainty as to a final standard on accounting for rate-regulated activities.

(b) Investment Property

IAS 40, *Investment Property* ("IAS 40") defines investment property as land or buildings held to earn rental income, for capital appreciation or both. The Corporation's real estate assets, which are currently owned by its non-regulated subsidiary, Fortis Properties, and recorded as property, plant and equipment under Canadian GAAP, will be reclassified as investment property under IFRS.

IAS 40 and IFRS 1 provide the Corporation with an elective option to reset the cost of investment property based on fair value at the date of transition. IAS 40 provides further options for measuring investment property subsequent to initial recognition using either the cost or the fair value model. Currently, Fortis Properties intends to reset the cost of its investment property upon transition to IFRS based on fair value as at January 1, 2010 and to use the fair value model to measure its investment property subsequent to transition. Use of the fair value model under IAS 40 means that the Corporation will not recognize depreciation expense with respect to its investment properties in its statement of earnings under IFRS and that any change in the fair value of its investment properties subsequent to initial recognition will be recognized in earnings in the period when the change occurs.

(c) Provisions and Contingent Liabilities

IAS 37, *Provisions, Contingent Liabilities and Contingent Assets* ("IAS 37") requires a provision to be recognized when: (i) there is a present obligation as a result of a past transaction or event; (ii) it is probable that an outflow of resources will be required to settle the obligation; and (iii) a reliable estimate can be made of the obligation. The threshold for recognizing a provision under Canadian GAAP is higher than under IFRS. It is possible, therefore, that some contingent liabilities which would not have been recognized under Canadian GAAP may meet the criteria for recognition as a provision under IFRS.

In January 2010, the IASB published an Exposure Draft – *Measurement of Liabilities in IAS 37* ("ED/2010/1"). The publication of ED/2010/1 is part of a larger IASB project, which has been ongoing since 2005 and which is intended to result in a new IFRS to replace IAS 37. ED/2010/1 is open for public comment until April 12, 2010. Based on comments received on ED/2010/1, and previous tentative decisions by the IASB with respect to other aspects of IAS 37, a final IFRS to replace IAS 37 is planned for release in the third quarter of 2010.

(d) Employee Benefits

IAS 19, *Employee Benefits* ("IAS 19") requires past service costs associated with defined benefit plans to be expensed on an accelerated basis with vested past service costs to be expensed immediately and unvested past service costs to be expensed on a straight-line basis until the benefits become vested. In addition, actuarial gains and losses are permitted to be recognized directly in equity rather than through earnings, and IFRS 1 also provides an option to recognize immediately in retained earnings all cumulative actuarial gains and losses existing as at the date of transition to IFRS.

Under Canadian GAAP, past service costs are generally amortized on a straight-line basis over the expected average remaining service period of active employees in the defined benefit plan.

The Corporation and its subsidiaries maintain a number of defined benefit pension plans and supplementary and other post-employment benefit plans, which will be subject to different accounting treatment under IFRS versus Canadian GAAP. However, the full extent of the impact of applying IAS 19 by the Corporation and its subsidiaries cannot be made at this time, pending further certainty as to a final standard on accounting for rate-regulated activities.

(e) Impairment of Assets

IAS 36, *Impairment of Assets* ("IAS 36") uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of value in use and fair value less costs to sell. Value in use is defined as being equal to the present value of future cash flows expected to be derived from the asset in its current state. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP where undiscounted future cash flows are used to compare against the asset's carrying value to determine if impairment exists. This may result in more frequent write-downs in the carrying value of assets under IFRS since asset carrying values that were previously supported under Canadian GAAP based on undiscounted cash flows may not be supported on a discounted cash flow basis under IFRS. However, under IAS 36, previous impairment losses may be reversed where circumstances change such that the impairment has been reduced. This also differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

As the majority of the Corporation's assets are owned by utility subsidiaries that are rate regulated, the potential for and extent of any impairment losses will be primarily subject to the continued ability of the utilities to recover costs through the regulatory process.

As stated above, the Corporation intends to reset the cost of investment property owned by its non-regulated subsidiary, Fortis Properties, upon transition to IFRS based on fair value as at January 1, 2010 and to use the fair value model to measure its investment property subsequent to transition. Changes in the fair value of the Corporation's investment property each period will, therefore, be reflected under IFRS in the statement of earnings.

The Corporation's other non-regulated assets will be subject to the one-step approach under IFRS for testing and measuring asset impairments, which may result in some impairments being recognized or reversed under IFRS that would not have been required or permitted under Canadian GAAP.

The Corporation is continuing to assess the impact of adopting IAS 36. Currently, however, Fortis does not expect to incur any material asset impairments upon transition to IFRS.

(f) Income Taxes

IAS 12, *Income Taxes* ("IAS 12") prescribes that an entity account for the tax consequences of transactions and other events in the same way that it accounts for the transactions and other events themselves. Therefore, where transactions and other events are recognized in earnings, the recognition of deferred tax assets or liabilities that arise from those transactions should also be recorded in earnings. For transactions that are recognized outside the statement of earnings, either in other comprehensive income or directly in equity, any related tax effects should also be recognized outside the statement of earnings.

The most significant impact of IAS 12 on the Corporation will be derived directly from the accounting policy decisions made under IAS 16 and IAS 40. In addition, the Corporation's rate-regulated utilities currently account for income taxes based on regulatory decisions. Therefore, the impact on the Corporation of accounting for the tax consequences of transactions and other events under IFRS versus Canadian GAAP cannot be fully determined at this time pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(g) Business Combinations

Under IFRS 3, *Business Combinations* ("IFRS 3"), business combinations must be accounted for by applying the acquisition method. One of the parties to a business combination can always be identified as the acquirer, being the entity that obtains control of the other business. Control is defined as the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Fortis, as an acquirer, shall identify the date on which it obtains control of an acquiree. This date is usually the closing date of the acquisition, which would generally be the date on which the Corporation legally transfers the consideration or acquires the assets and assumes the liabilities of the acquiree. As of the date on which it obtains control, Fortis shall recognize, separately from goodwill, the identifiable assets acquired, the liabilities assumed and any non-controlling interest in the acquiree in accordance with IFRS 3.

In accordance with IFRS 3, acquisition-related costs incurred to effect a business combination shall be expensed in the period the costs are incurred. Under IFRS, these costs are not permitted to form a component of goodwill as is permitted under Canadian GAAP.

Under IFRS 1, an entity has the option to retroactively apply IFRS 3 to all business combinations or may elect to apply the standard prospectively only to those business combinations that occur after the date of transition. The Corporation currently intends to avail of the elective exemption under IFRS 1, which removes the requirement to retrospectively restate any business combinations prior to the date of transition to IFRS, subject to certain balance sheet adjustments that may be required by FortisAlberta with respect to goodwill it had recorded based on its previous owner's application of pushdown accounting under Canadian GAAP. These balance sheet adjustments by FortisAlberta are not expected to have an impact on the Corporation's consolidated financial position upon transition to IFRS.

The AcSB recently issued new CICA Handbook Section 1582, *Business Combinations* and Section 1602, *Non-Controlling Interests.* The effective date of these sections is fiscal years beginning on or after January 1, 2011; however, early adoption is permitted. The Corporation expects to apply these new Handbook sections prospectively to any business combinations that occur on or after January 1, 2010. These new Handbook sections are substantially aligned with the accounting for business combinations and non-controlling interests under IFRS 3. Further information related to the above two new Canadian standards is provided under the heading "Future Accounting Changes – Business Combinations".

(h) IFRS 1, First-Time Adoption of IFRS

IFRS 1 provides the framework for the first-time adoption of IFRS and specifies that, in general, an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other GAAP should be recognized directly in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided for under IFRS 1.

The Corporation has completed an analysis of IFRS 1. While preliminary decisions have been made with respect to the elective exemptions available upon transition, final decisions cannot be made at this time pending further certainty as to a final IFRS standard on accounting for rate-regulated activities.

(i) Internal Controls over Financial Reporting and Disclosure

In accordance with the Corporation's approach to certification of internal controls required under Canadian Securities Administrators' National Instrument 52-109, all entity-level, information technology, disclosure and business process controls will require updating and testing to reflect changes arising from the Corporation's conversion to IFRS. Where material changes are identified, these changes will be mapped and tested to ensure that no material control deficiencies exist as a result of the Corporation's conversion to IFRS.

(j) Information Systems

It is anticipated that the adoption of IFRS will have some impact on information systems requirements. The Corporation and its subsidiaries have assessed the need for systems upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two of the Corporation's IFRS Conversion Project, information systems plans have been prepared for implementation in Phase Three. The extent of the impact on information systems is largely dependent upon certainty as to a final IFRS standard on accounting for rate-regulated activities.

The IASB has a number of ongoing projects on its agenda, in addition to the project on accounting for rate-regulated activities, that may result in changes to existing IFRS prior to the Corporation's conversion to IFRS in 2011. The Corporation continues to monitor these projects and the impact that any resulting IFRS changes may have on its accounting policies, financial position or results of operations under IFRS for 2011 and beyond.

Business Combinations

In January 2009, the AcSB issued new CICA Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements* and Section 1602, *Non-Controlling Interests*. These new standards are effective for fiscal years beginning on or after January 1, 2011 with early adoption permitted. The Corporation has chosen to early adopt the above standards as at January 1, 2010. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. 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 will affect the recognition of business combinations completed by the Corporation on or after January 1, 2010 and, as a result, may have a material impact on the Corporation's consolidated earnings and financial position.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result 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 and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of Sections 1601 and 1602 is not expected to have a material impact on the Corporation's consolidated earnings, cash flows or financial position.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, other assets and deferred credits in 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.

A decrease in credit risk and spreads, as a result of the improvement in and decreased volatility experienced in the financial and capital markets in the latter part of 2009, has resulted in a higher fair value relative to carrying value for the Corporation's consolidated long-term debt and preference shares as at December 31, 2009 compared to December 31, 2008.

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	**2009**		2008	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[1]	**5,502**	**5,906**	5,122	5,040
Preference shares, classified as debt[2]	**320**	**348**	320	329

[1] Carrying value as at December 31, 2009 excludes unamortized deferred financing costs of $39 million (December 31, 2008 – $34 million) and capital lease obligations of $37 million (December 31, 2008 – $36 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 $347 million preference shares classified as equity was $356 million as at December 31, 2009 (December 31, 2008 – carrying value of $347 million; fair value of $268 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	**2009**				2008	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest rate swaps	**1**	**1**	**–**	**–**	–	–
Foreign exchange forward contract	**< 2**	**1**	**–**	**–**	7	7
Natural gas derivatives:						
Swaps and options	**Up to 5**	**223**	**(119)**	**(119)**	(84)	(84)
Gas purchase contract premiums	**Up to 2**	**69**	**(3)**	**(3)**	(8)	(8)

The interest rate swap is held by Fortis Properties and is designated as a hedge of the cash flow risk related to floating-rate long-term debt and matures in October 2010. The effective portion of the change in the fair value of the interest rate swap at Fortis Properties is recorded in other comprehensive income. During 2009, another interest rate swap held by Fortis Properties matured.

The foreign exchange forward contract is held by TGVI and hedges the cash flow risk related to approximately US$15 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.

The changes in the fair values of the foreign exchange forward contract 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 value of the foreign exchange forward contract was recorded in accounts receivable as at December 31, 2009 and 2008. The fair value of the natural gas derivatives was recorded in accounts payable as at December 31, 2009 and 2008.

The interest rate swap is valued at the present value of future cash flows based on published forward future interest rate curves. The foreign exchange forward contract is valued using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. The 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 values of the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts as at the balance sheet date.

The fair value of the Corporation's financial instruments, including derivatives, reflects 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 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 reported 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 recorded 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 recorded 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 reported in earnings in the period in which they become known. As at December 31, 2009, Fortis recorded $981 million in current and long-term regulatory assets (December 31, 2008 – $360 million) and $489 million in current and long-term regulatory liabilities (December 31, 2008 – $434 million). The increase in regulatory assets and liabilities year over year reflected the recording of regulatory assets and liabilities, effective January 1, 2009, associated with the recognition of future income taxes upon adoption of amended accounting standards pertaining to income taxes. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2009 Consolidated Financial Statements.

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, 2009, the Corporation's consolidated utility capital assets, income producing properties and intangibles were approximately $8.5 billion, or approximately 70 per cent of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangibles of approximately $8.0 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2008. The increase in capital assets was primarily associated with capital expenditures, which totalled more than $1 billion in 2009. Amortization expense for 2009 was $364 million compared to $348 million for 2008. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization expense.

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 future 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 recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability as at December 31, 2009 was $326 million (December 31, 2008 – $325 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2009 was $29 million (2008 – $27 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation 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 expense, when the differences are refunded or collected in customer rates as approved by the regulator. During the fourth quarter of 2009, Fortis Turks and Caicos completed a depreciation study. The impact was a change in depreciation estimates resulting in a favourable adjustment of approximately $1.5 million to amortization expense in the fourth quarter.

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. The use of estimation with respect to recording future income taxes has increased due to the adoption by the Corporation of amended CICA Handbook Section 3465, *Income Taxes*, effective January 1, 2009. 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 recorded and charged 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. 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 is 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 2009 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 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 future profitability of the reporting units. There was no impairment provision required on approximately $1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2009.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and other post-employment benefit ("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 rates of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2010, are 7 per cent for the larger defined benefit pension plans. This rate compares to assumed long-term rates of return used in 2009 that ranged from 7.00 per cent to 7.25 per cent. The defined benefit pension plan assets experienced total positive returns during 2009 of approximately $71 million compared to expected positive returns of $46 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2009 and to determine net pension cost for 2010 range from 5.75 per cent to 6.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2008 and determine net pension cost for 2009 that ranged from 6.00 per cent to 7.50 per cent. The discount rates decreased, driven mainly by lower credit risk spreads 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.

The discount rates and fair value of the assets for the defined benefit pension plans at FortisAlberta, FortisBC, FortisOntario and Algoma Power are as of a September 30, 2009 measurement date and thus would not reflect the impact of any changes in capital market conditions to the end of 2009.

There was no material increase in consolidated defined benefit net pension cost for 2009 compared to 2008. For 2009, the amortization of 2008 losses associated with the pension plan assets was largely offset by the impact of higher assumed discount rates for calculating net pension cost in 2009 compared to 2008. Consolidated defined benefit net pension cost for 2009 was also not materially impacted by the outcome of actuarial valuations completed in the first quarter of 2009, as described in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A.

Consolidated defined benefit net pension cost for 2010 is expected to be higher than for 2009, 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 move in the expected long-term rate of return on pension plan assets and the discount rate on 2009 defined benefit net 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. 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, 2009

Increase (decrease)	**Net pension benefit cost**		**Accrued benefit asset**		**Accrued benefit liability**		**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	(3)	(4)	3	4	–	–	–	–
Impact of decreasing the rate of return assumption by 100 basis points	3	4	(3)	(4)	–	–	–	–
Impact of increasing the discount rate assumption by 100 basis points	(1)	(2)	–	2	(1)	–	(27)	(46)
Impact of decreasing the discount rate assumption by 100 basis points	1	5	–	(4)	1	–	33	53

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 record 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. As disclosed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the Terasen Gas companies, 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, 2009, the Corporation had a consolidated accrued benefit asset of $146 million (December 31, 2008 – $133 million) and a consolidated accrued benefit liability of $186 million (December 31, 2008 – $168 million). During 2009, the Corporation recorded a consolidated net benefit cost of $26 million (2008 – $27 million) for all defined benefit and OPEB plans.

Asset-Retirement Obligations: The measurement of the fair value of asset-retirement obligations ("AROs") 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 recorded as at December 31, 2009 and 2008. 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 distribution and transmission 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 recorded at that time provided the costs can be reasonably estimated.

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. Recording 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, 2009, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $294 million (December 31, 2008 – $365 million) on annual consolidated revenue of approximately $3.6 billion (2008 – $3.9 billion).

Capitalized Overhead: As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Fortis Turks and Caicos and, commencing in May 2008, 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 2009, GEC totalled $57 million (2008 – $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 recorded as operating expenses versus utility capital assets.

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

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

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. TGI was successful in its appeal to the Supreme Court of British Columbia in June 2009. The Province of British Columbia has been granted leave to appeal the decision to the British Columbia Court of Appeal.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the 2009 Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

On July 16, 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 a pipeline rupture in July 2007. Terasen has filed a statement of defence but the claim is in its early stages and the amount and outcome of it is indeterminable at this time and, accordingly, no amount has been accrued in the 2009 Consolidated Financial Statements.

In 2008, the Vancouver Island Gas Joint Venture ("VIGJV") commenced a lawsuit against TGVI seeking damages for alleged overpayments of past tolls and declarations for reduction of its future tolls. The Statement of Claim did not quantify damages and the case did not reach the stage where either party formally quantified VIGJV's claims. In December 2009, VIGJV abandoned its claim and in January 2010, the lawsuit was dismissed by consent dismissal order. The matter is now fully concluded.

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. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2009 Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of Point Lepreau in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation, which confirmed the April 2006 reassessments. In March 2009, the Company filed an Appeal to the Tax Court of Canada.

Should Maritime Electric be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $14 million in taxes and accrued interest. As at December 31, 2009, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

Exploits Partnership

The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generation 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, a Crown corporation, 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 has 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, 2009, 2008 and 2007. 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)*	**2009**	2008	2007[(1)]
Revenue	**3,637**	3,903	2,718
Net earnings	**280**	259	199
Net earnings applicable to common shares	**262**	245	193
Total assets	**12,160**	11,166	10,282
Long-term debt and capital lease obligations (excluding current portion)	**5,276**	4,884	4,623
Preference shares[(2)]	**667**	667	442
Common shareholders' equity	**3,193**	3,046	2,601
Basic earnings per common share	**1.54**	1.56	1.40
Diluted earnings per common share	**1.51**	1.52	1.32
Dividends declared per common share	**0.78**	1.01	0.88
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G[(3)]	**1.3125**	1.0184	–

(1) Financial results for 2007 include the financial results of Terasen from May 17, 2007, the date of acquisition by Fortis.

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

(3) A total of 9.2 million 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, and which are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum.

2009/2008: Revenue decreased $266 million, or 6.8 per cent, 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 basic customer rate increases, and customer growth mainly in Canada, in addition to the favourable impact of foreign currency translation. Net earnings applicable to common shares grew $17 million, or 6.9 per cent, 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 additional costs 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 deemed equity component of the total capital structure 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 in April 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 per cent, from 2008 due to dilution associated with the issuance of $300 million common shares in December 2008.

2008/2007: Revenue increased approximately $1.2 billion, or 43.6 per cent, over 2007. The increase was driven by contribution from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. Net earnings applicable to common shares grew $52 million, or 26.9 per cent, over 2007. The increase in earnings was primarily due to earnings' contribution from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian Regulated Utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time $13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate income tax recoveries at FortisAlberta. The growth in total assets and increase in long-term debt in 2008 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, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. The Corporation issued $230 million preference shares in 2008, the net proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. The Corporation also issued $300 million common shares in 2008, the net proceeds of which were used to repay short-term debt primarily incurred to retire $200 million of maturing debt at Terasen, and for general corporate purposes. Basic earnings per common share increased 16 cents, or 11.4 per cent, from 2007, primarily due to growth in earnings.

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2009 and 2008. 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 2009 is also contained in the Corporation's fourth quarter 2009 media release, dated and filed on SEDAR at www.sedar.com on February 4, 2010, 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)*		
	2009	2008	Variance	**2009**	2008	Variance
Regulated Gas Utilities – Canadian						
Terasen Gas Companies	**65,000**	66,816	(1,816)	**497**	606	(109)
Regulated Electric Utilities – Canadian						
FortisAlberta	**4,129**	4,068	61	**86**	78	8
FortisBC	**859**	842	17	**69**	66	3
Newfoundland Power	**1,474**	1,412	62	**146**	139	7
Other Canadian	**582**	543	39	**77**	65	12
	7,044	6,865	179	**378**	348	30
Regulated Electric Utilities – Caribbean	**290**	364	(74)	**85**	159	(74)
Non-Regulated – Fortis Generation	**87**	312	(225)	**5**	20	(15)
Non-Regulated – Fortis Properties				**53**	52	1
Corporate and Other				**6**	6	–
Inter-Segment Eliminations				**(6)**	(10)	4
Total				**1,018**	1,181	(163)

Gas Volumes: Gas volumes at the Terasen Gas companies decreased quarter over quarter, mainly due to lower average consumption by core residential customers.

Energy and Electricity Sales: Increased energy and electricity sales at Regulated Electric Utilities – Canadian quarter over quarter were driven by customer growth at FortisAlberta, FortisBC and Newfoundland Power, and contribution from Algoma Power, which has been included in the financial results reported in the Other Canadian Regulated Electric Utilities' segment from October 8, 2009, the date of acquisition by FortisOntario, partially offset by the negative impact on consumption at the Other Canadian Regulated Electric Utilities, due to the temporary shutdown of two commercial potato-processing plants on Prince Edward Island and lower average consumption as a result of the economic downturn.

Decreased electricity sales at Regulated Electric Utilities – Caribbean were driven by the impact of two additional months of contribution from Caribbean Utilities in the fourth quarter of 2008 (August and September 2008) related to a change in the utility's fiscal year end. The decrease was partially offset by the favourable impact on consumption as a result of warmer average temperatures experienced in the region compared to the same quarter in 2008 and the loss of electricity sales during the third and fourth quarters of 2008 at Fortis Turks and Caicos as a result of Hurricane Ike, which struck in September 2008. Tempering electricity sales growth, however, was the negative impact of the economic downturn on consumption by residential customers and activities in the tourism, oil, construction and related industries.

At Non-Regulated – Fortis Generation, 164 GWh of the total decrease in energy sales quarter over quarter was due to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. In addition, 46 GWh of the total decrease in energy sales quarter over quarter related to generation operations in central Newfoundland. Energy sales for 2009 included sales related to central Newfoundland operations for only 1½ months compared to the entire year in 2008, due to the discontinuance of the consolidation method of accounting for these operations in February 2009. The remaining decrease in total energy sales was mainly due to the impact of lower production in Belize and Upper New York State driven by lower rainfall.

Revenue: The decrease in revenue at the Terasen Gas companies was largely due to the lower commodity cost of natural gas charged to customers and lower consumption, partially offset by higher basic customer delivery rates and the rate revenue accrual, during the fourth quarter of 2009, related to the cumulative retroactive impact of an increase in the allowed ROEs for the Terasen Gas companies, effective July 1, 2009.

The increase in revenue at Regulated Electric Utilities – Canadian was mainly due to basic customer rate increases and customer growth, combined with contribution from Algoma Power, from October 2009, and the rate revenue accrual, during the fourth quarter of 2009, related to the cumulative retroactive impact of an increase in FortisAlberta's allowed ROE to 9.00 per cent, effective January 1, 2009, from an interim allowed ROE of 8.51 per cent and an increase in the deemed equity component of the total capital structure to 41 per cent from 37 per cent.

Revenue at Regulated Electric Utilities – Caribbean decreased quarter over quarter, mainly due to the flow through to customers of lower energy supply costs at Caribbean Utilities, two additional months of contribution from Caribbean Utilities in the fourth quarter of 2008 (August and September 2008) for the reason described above, and the unfavourable impact of foreign currency translation. Partially offsetting the above factors was the impact of a 2.4 per cent increase in basic electricity rates at Caribbean Utilities, effective June 1, 2009, and otherwise increased electricity sales when comparing electricity sales for the same three-month period quarter over quarter for Caribbean Utilities.

Revenue from Non-Regulated – Fortis Generation decreased quarter over quarter, primarily due to the loss of revenue subsequent to the expiration of the Rankine water rights, as described above, the impact of the discontinuance of the consolidation method of accounting for the financial results of the generation operations in central Newfoundland in February 2009, as described above, lower average wholesale market energy prices per MWh in Upper New York State, which were US$40.66 for the fourth quarter of 2009 compared to US$56.86 for the same quarter in 2008, and decreased production in Upper New York State and Belize.

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2009**	2008	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**48**	47	1
Regulated Electric Utilities – Canadian			
FortisAlberta	**15**	11	4
FortisBC	**8**	7	1
Newfoundland Power	**8**	8	–
Other Canadian	**6**	3	3
	37	29	8
Regulated Electric Utilities – Caribbean	**7**	8	(1)
Non-Regulated – Fortis Generation	**3**	8	(5)
Non-Regulated – Fortis Properties	**5**	4	1
Corporate and Other	**(19)**	(20)	1
Net Earnings Applicable to Common Shares	**81**	76	5

Earnings: Earnings for the fourth quarter of 2009 were $81 million or $5 million higher than $76 million for the same quarter in 2008. Fourth quarter results for 2009 were favourably impacted by a one-time $3 million adjustment to future income taxes related to prior periods at FortisOntario and were unfavourably impacted by a one-time $5 million after-tax provision for additional costs related to the conversion of Whistler customer appliances from propane to natural gas. Fourth quarter results for 2008 included two additional months of earnings' contribution from Caribbean Utilities (August and September 2008) of approximately $2 million due to a change in the utility's fiscal year end. Excluding the above one-time items, earnings increased $9 million quarter over quarter. The increase was driven by: (i) the approximate $10 million cumulative retroactive impact in the fourth quarter of 2009 associated with the increase in the allowed ROEs for 2009 for FortisAlberta and TGI, and an increase in the deemed equity component of the total capital structure at FortisAlberta; and (ii) a change in depreciation estimates at Fortis Turks and Caicos, which favourably impacted depreciation expense for the fourth quarter of 2009. The increase was partially offset by the loss of earnings subsequent to the expiration of the Rankine water rights in April 2009.

Summary of Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2009**	2008	Variance
Cash, Beginning of Period	**106**	68	38
Cash Provided By (Used In)			
Operating Activities	**70**	208	(138)
Investing Activities	**(312)**	(272)	(40)
Financing Activities	**222**	59	163
Foreign Currency Impact on Cash Balances	**(1)**	3	(4)
Cash, End of Period	**85**	66	19

Cash flow provided by operating activities, after working capital adjustments, decreased $138 million quarter over quarter. The decrease was mainly due to 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 quarter over quarter, and the timing of the declaration of common share dividends.

Cash used in investing activities increased $40 million quarter over quarter, reflecting the acquisition of Algoma Power during the fourth quarter of 2009 for approximately $70 million, net of cash acquired, compared to the acquisition of the Sheraton Hotel Newfoundland during the fourth quarter of 2008 for approximately $22 million, partially offset by lower capital spending by the utilities in the Caribbean.

Cash provided by financing activities was $163 million higher quarter over quarter, primarily due to a net increase in debt during the fourth quarter of 2009 compared to a net decrease in debt during the fourth quarter of 2008, partially offset by lower proceeds from common share offerings. During the fourth quarter of 2008, Fortis issued $300 million in common shares.

Summary of Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2008 through December 31, 2009. 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)

	Revenue	**Net Earnings Applicable to Common Shares**	**Earnings per Common Share**	
Quarter Ended	*($ millions)*	*($ millions)*	**Basic** *($)*	**Diluted** *($)*
December 31, 2009	1,018	81	0.48	0.46
September 30, 2009	664	36	0.21	0.21
June 30, 2009	754	53	0.31	0.31
March 31, 2009	1,201	92	0.54	0.52
December 31, 2008	1,181	76	0.48	0.46
September 30, 2008	727	49	0.31	0.31
June 30, 2008	848	29	0.19	0.18
March 31, 2008	1,146	91	0.58	0.55

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 have been impacted, as expected, by 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 second quarter ended June 30, 2008 reflected the $13 million unfavourable impact to Fortis of a charge recorded at Belize Electricity as a result of the June 2008 regulatory rate decision. Financial results for the fourth quarter ended December 31, 2008 included two additional months of contribution from Caribbean Utilities resulting from a change in the utility's fiscal year end. To a lesser degree, financial results from November 2008 were impacted by the acquisition of the Sheraton Hotel Newfoundland, from April 2009 by the acquisition of the Holiday Inn Select Windsor, and from October 2009 by the acquisition of Algoma Power.

December 2009/December 2008 – Net earnings applicable to common shares were $81 million, or $0.48 per common share, for the fourth quarter of 2009 compared to earnings of $76 million, or $0.48 per common share, for the fourth quarter of 2008. A discussion of the variances between the financial results for the fourth quarter of 2009 and the fourth quarter of 2008 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2009/September 2008 – Net earnings applicable to common shares were $36 million, or $0.21 per common share, for the third quarter of 2009 compared to earnings of $49 million, or $0.31 per common share, for the third quarter of 2008. Third quarter 2008 results included a tax reduction of approximately $7.5 million associated with the settlement of historical corporate tax matters at Terasen and a $4.5 million recovery of future income taxes, which was previously expensed during the first half of 2008 at FortisAlberta. Earnings were $1 million lower quarter over quarter, excluding the above one-time tax reductions. The impact of lower effective corporate income taxes at the Terasen Gas companies and growth in electrical infrastructure investment and higher net transmission revenue at FortisAlberta was more than offset by lower earnings from non-regulated hydroelectric generation and lower earnings at Newfoundland Power. The decrease in earnings from non-regulated hydroelectric generation was primarily associated with the loss of earnings subsequent to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario. Lower earnings at Newfoundland Power were largely associated with higher operating expenses and amortization costs.

June 2009/June 2008 – Net earnings applicable to common shares were $53 million, or $0.31 per common share, for the second quarter of 2009 compared to earnings of $29 million, or $0.19 per common share, for the second quarter of 2008. Results for the second quarter of 2008 included one-time charges of approximately $15 million pertaining to Belize Electricity, associated with the June 2008 regulatory rate decision, and FortisOntario, associated with the repayment, during the second quarter of 2008, of an interconnection agreement-related refund received in the fourth quarter of 2007. Excluding these one-time charges, earnings increased $9 million quarter over quarter, driven by lower corporate income taxes and growth in electrical infrastructure investment at FortisAlberta, and lower corporate income taxes at the Terasen Gas companies. The increase was partially offset by lower earnings from non-regulated hydroelectric generation primarily associated with the loss of earnings subsequent to the expiration, on April 30, 2009, of the water rights of the Rankine hydroelectric generating facility in Ontario.

March 2009/March 2008 – Net earnings applicable to common shares were $92 million, or $0.54 per common share, for the first quarter of 2009 compared to earnings of $91 million, or $0.58 per common share, for the first quarter of 2008. Results were driven by growth in electrical infrastructure investment and customers at the Regulated Electric Utilities in western Canada, partially offset by lower earnings at Regulated Electric Utilities – Caribbean and Fortis Properties. Excluding one-time gains of approximately $2 million at Fortis Turks and Caicos in 2009, earnings at Regulated Electric Utilities – Caribbean were $3 million lower quarter over quarter, resulting from reduced electricity sales attributable to cooler temperatures and the impact of the economic downturn on energy demand, combined with the lower allowed ROAs at Caribbean Utilities and Belize Electricity. The decrease was partially mitigated by the favourable impact of foreign exchange rates associated with the strengthening US dollar quarter over quarter. Fortis Properties' results were reduced by one-time transitional operating costs associated with the Sheraton Hotel Newfoundland, acquired in November 2008, and the impact of lower hotel occupancies.

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, 2009 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, 2009 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2009, 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

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

Outlook

The Corporation's significant capital program, which is expected to approach $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 strategic opportunities to acquire regulated natural gas and electric utilities in the United States, Canada and the Caribbean. 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, 2010, the Corporation had issued and outstanding 172.1 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, 2010 is as follows:

Conversion of Securities into Common Shares

As at March 1, 2010 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	**5.5**
Convertible Debt	**1.4**
First Preference Shares, Series C	**4.7**
First Preference Shares, Series E	**7.6**
Total	**19.2**

Additional information, including the Fortis 2009 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.

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2009 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2009 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 2009 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2009 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 2009 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

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2009 and 2008 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2009 and 2008 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
February 4, 2010

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	2009	2008
Current assets		*(Restated – Note 2)*
Cash and cash equivalents	**$ 85**	$ 66
Accounts receivable	**595**	681
Prepaid expenses	**16**	17
Regulatory assets *(Note 4)*	**223**	157
Inventories *(Note 5)*	**178**	229
Future income taxes *(Note 19)*	**29**	–
	1,126	1,150
Other assets *(Note 6)*	**174**	230
Regulatory assets *(Note 4)*	**758**	203
Future income taxes *(Note 19)*	**17**	54
Utility capital assets *(Note 7)*	**7,687**	7,141
Income producing properties *(Note 8)*	**559**	540
Intangible assets *(Note 9)*	**279**	273
Goodwill *(Note 10)*	**1,560**	1,575
	$ 12,160	$ 11,166
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 26)*	**$ 415**	$ 410
Accounts payable and accrued charges	**852**	874
Dividends payable	**3**	47
Income taxes payable	**23**	66
Regulatory liabilities *(Note 4)*	**53**	45
Current installments of long-term debt and capital lease obligations *(Note 11)*	**224**	240
Future income taxes *(Note 19)*	**24**	15
	1,594	1,697
Deferred credits *(Note 12)*	**295**	277
Regulatory liabilities *(Note 4)*	**436**	389
Future income taxes *(Note 19)*	**576**	61
Long-term debt and capital lease obligations *(Note 11)*	**5,276**	4,884
Non-controlling interest *(Note 13)*	**123**	145
Preference shares *(Note 14)*	**320**	320
	8,620	7,773
Shareholders' equity		
Common shares *(Note 15)*	**2,497**	2,449
Preference shares *(Note 14)*	**347**	347
Contributed surplus	**11**	9
Equity portion of convertible debentures *(Note 11)*	**5**	6
Accumulated other comprehensive loss *(Note 17)*	**(83)**	(52)
Retained earnings	**763**	634
	3,540	3,393
	$ 12,160	$ 11,166

Commitments *(Note 27)*
Contingent Liabilities *(Note 28)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Geoffrey Hyland

Geoffrey F. Hyland,
Director

David G. Norris,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	2009	2008
Revenue	**$ 3,637**	$ 3,903
Expenses		
Energy supply costs	**1,799**	2,112
Operating	**773**	743
Amortization	**364**	348
	2,936	3,203
Operating Income	**701**	700
Finance charges *(Note 18)*	**360**	363
Earnings Before Corporate Taxes and Non-Controlling Interest	**341**	337
Corporate taxes *(Note 19)*	**49**	65
Net Earnings Before Non-Controlling Interest	**292**	272
Non-controlling interest	**12**	13
Net Earnings	**280**	259
Preference share dividends	**18**	14
Net Earnings Applicable to Common Shares	**$ 262**	$ 245
Earnings Per Common Share *(Note 15)*		
Basic	**$ 1.54**	$ 1.56
Diluted	**$ 1.51**	$ 1.52

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)	2009	2008
Balance at Beginning of Year	**$ 634**	$ 551
Net Earnings Applicable to Common Shares	**262**	245
	896	796
Dividends on Common Shares	**(133)**	(162)
Balance at End of Year	**$ 763**	$ 634

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)	2009	2008
Net Earnings	**$ 280**	$ 259
Other Comprehensive Income (Loss)		
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**(90)**	115
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**67**	(92)
Corporate tax (expense) recovery	**(9)**	13
Change in Unrealized Foreign Currency Translation (Losses) Gains, Net of Hedging Activities and Tax *(Note 17)*	**(32)**	36
Gain on Derivative Instruments Designated as Cash Flow Hedges, Net of Tax	**1**	–
Comprehensive Income	**$ 249**	$ 295

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)	**2009**	2008
Operating Activities		*(Restated – Note 2)*
Net earnings	**$ 280**	$ 259
Items not Affecting Cash:		
Amortization – utility capital assets and income producing properties	**317**	308
Amortization – intangible assets	**43**	37
Amortization – other	**4**	3
Future income taxes *(Note 19)*	**5**	14
Non-controlling interest	**12**	13
Write-down of deferred power costs – Belize Electricity *(Note 4)*	**–**	18
Other	**(8)**	(7)
Change in long-term regulatory assets and liabilities	**25**	(23)
	678	622
Change in non-cash operating working capital	**(41)**	39
	637	661
Investing Activities		
Change in other assets and deferred credits	**(8)**	5
Capital expenditures – utility capital assets	**(966)**	(872)
Capital expenditures – income producing properties	**(26)**	(14)
Capital expenditures – intangible assets	**(32)**	(49)
Contributions in aid of construction	**56**	85
Proceeds on sale of capital assets	**1**	15
Business acquisitions, net of cash acquired *(Note 21)*	**(77)**	(22)
	(1,052)	(852)
Financing Activities		
Change in short-term borrowings	**8**	(69)
Proceeds from long-term debt, net of issue costs	**729**	662
Repayments of long-term debt and capital lease obligations	**(172)**	(431)
Net repayments under committed credit facilities	**(14)**	(309)
Advances from non-controlling interest	**2**	3
Issue of common shares, net of costs	**46**	308
Issue of preference shares, net of costs	**–**	223
Dividends		
Common shares	**(133)**	(162)
Preference shares	**(18)**	(14)
Subsidiary dividends paid to non-controlling interest	**(10)**	(15)
	438	196
Effect of exchange rate changes on cash and cash equivalents	**(4)**	3
Change in Cash and Cash Equivalents	**19**	8
Cash and Cash Equivalents, Beginning of Year	**66**	58
Cash and Cash Equivalents, End of Year	**$ 85**	$ 66

Supplementary Information to Consolidated Statements of Cash Flows *(Note 23)*

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

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 Corporation's long-term objectives. 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 following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

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 primarily 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 primarily 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 newly converted natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service mainly to 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.

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 Cominco Metals Ltd., the 149-MW Brilliant hydroelectric plant and 120-MW Brilliant 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 the principal distributor of electricity in Newfoundland. Newfoundland Power 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 the principal distributor of electricity on Prince Edward Island. 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 21). 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 ten-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies.

Regulated Electric Utilities – Caribbean

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

b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed generating capacity of 153 MW. Fortis holds an approximate 59 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Previously, Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. In 2008, Caribbean Utilities changed its fiscal year end to December 31, which has eliminated the previous two-month lag in consolidating its financial results.

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 the principal distributor of electricity in the Turks and Caicos Islands. The Company has a combined diesel-powered generating capacity of 54 MW.

Non-Regulated – Fortis Generation

a. *Belize*: Operations consist of the 25-MW Mollejon, the 7-MW Chalillo and, as of March 2010, the 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 per cent interest in the Exploits Partnership and Abitibi holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro under a 30-year power purchase agreement expiring in 2033. Effective February 12, 2009, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership (Note 28).

d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. The plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.

e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, 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 2.8 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 corporate 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 per cent 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. 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. 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 Note 2 under the headings Regulation, Utility Capital Assets, Intangibles, Employee Future Benefits, Income Taxes and Revenue Recognition, and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Effective January 1, 2009, the Canadian Accounting Standards Board (the "AcSB") amended the Canadian Institute of Chartered Accountants ("CICA") Handbook: (i) Section 1100, *Generally Accepted Accounting Principles*, removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes*, to require the recognition of future income tax liabilities and assets, as well as offsetting regulatory assets and liabilities, by entities subject to rate regulation.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Corporation must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under 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 4, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 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*. Therefore, there was no effect on the Corporation's consolidated financial statements as at January 1, 2009 as a result of the removal of the temporary exemption from Section 1100.

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 and FortisBC operate under cost of service 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 as a recent BCUC-approved Negotiated Settlement Agreement ("NSA") did not include a 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 and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service 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 the PBR mechanisms.

Under the previous PBR mechanism, TGI and 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 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 8.47 per cent for January through June 2009 and 9.50 per cent effective July 1, 2009 (2008 – 8.62 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.17 per cent for January through June 2009 and 10.00 per cent effective July 1, 2009 (2008 – 9.32 per cent) on a deemed capital structure of 40 per cent common equity. Effective January 1, 2010, the deemed equity component of TGI's capital structure increased to 40 per cent. FortisBC's allowed ROE was 8.87 per cent for 2009 (2008 – 9.02 per cent) on a deemed capital structure of 40 per cent common equity.

Previously, the allowed ROE at each of TGI, TGVI 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, the BCUC has set the allowed ROEs for TGI and TGVI at 9.50 per cent and 10.00 per cent, respectively, and effective January 1, 2010 has set the allowed ROE for FortisBC at 9.90 per cent. The BCUC has determined that the former automatic adjustment formula used to establish ROE 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 Board Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *AUC Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under cost of service 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 per cent for 2009 (2008 – 8.75 per cent) on a deemed capital structure of 41 per cent common equity (2008 – 37 per cent). The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service 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 to adjust 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 per cent for 2009, 2010 and, on an interim basis, 2011 and that the automatic adjustment formula used to establish ROE no longer apply until reviewed further by the AUC.

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 operation 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 cost of service 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, establish the revenue requirement upon which Newfoundland Power's customer rates are determined. While Newfoundland Power's allowed ROE has been set at 9.00 per cent by the PUB for 2010, the utility's allowed ROE is normally adjusted annually, between test years, through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields.

Newfoundland Power's allowed ROE for 2009 was 8.95 per cent (2008 – 8.95 per cent) on a deemed capital structure of 45 per cent common equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service 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 cost of service 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 per cent for 2009 (2008 – 10.00 per cent) on a deemed capital structure of 40 per cent common equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario
Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under cost of service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs.

December 31, 2009 and 2008

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

Regulation (cont'd)

Canadian Niagara Power's allowed ROE was 8.01 per cent for 2009 (2008 – 9.00 per cent) on a deemed capital structure of 43.3 per cent common equity (2008 – 46.7 per cent). In 2008, Canadian Niagara Power's electricity distribution rates were based upon costs derived from a 2004 historical test year whereas, effective May 1, 2009, electricity distribution rates were rebased using forecast 2009 costs. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure in 2010. Algoma Power's electricity distribution rates for 2009 were based upon costs derived from a 2007 historical test year. Algoma Power's allowed ROE was 8.57 per cent for 2009 on a deemed capital structure of 50 per cent common equity. In 2008, the OEB approved the use and implementation of the Rural and Remote Rate Protection ("RRRP") subsidy program, which applies to Algoma Power. The RRRP subsidy 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"). Belize Electricity's allowed ROA for 2009 was 10.00 per cent (2008 – 10.00 to 15.00 per cent from January to June 2008 and 10.00 per cent from July 1, 2008).

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The new 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 2009, effective June 1, were set in accordance with the licences, translating into a targeted allowed ROA range of 9.00 per cent to 11.00 per cent (2008 – 9.00 per cent to 11.00 per cent). 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 Government 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 per cent (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 Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfall. The submissions for 2009 calculated the Allowable Operating Profit for 2009 to be $24 million (US$21 million) and the cumulative shortfall at December 31, 2009 to be $37 million (US$32 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfall. The recovery would, however, be dependent on future sales volumes and expenses.

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 acquisition.

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.

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031, *Inventories*, and inventories of $26 million as at that date were reclassified to utility capital assets from inventories as they were held for the development, construction and maintenance of other utility capital assets.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions are at cost except for 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. Utility capital assets of all other utility operations are stated at cost.

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 expense at FortisAlberta, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense 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, 2009, the long-term regulatory liability for future asset removal and site restoration costs was $326 million (December 31, 2008 – $325 million) (Note 4 *(xvi)*).

As permitted by the regulator, the Terasen Gas companies and FortisBC 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 expense to represent a provision for future asset removal and site restoration costs. Based on new information that became available to the Company in late 2009, FortisBC now believes the portion of amortization expense and the related accumulated amortization that had previously been estimated as relating to the provisioning of future asset removal and site restoration costs is more appropriately presented and disclosed as accumulated amortization rather than as a provision for future asset removal and site restoration costs in regulatory liabilities. This presentation provides more reliable and relevant information about the effects of regulation on FortisBC (Note 30).

Effective January 1, 2010, as required by the regulator, the Terasen Gas companies are to record actual asset removal and site restoration costs, net of salvage proceeds, as operating expenses to be recovered from customers in current rates. Any difference between forecast net asset removal and site restoration costs used to set customer rates and actual net costs are subject to deferral account treatment.

FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings in the period incurred. These costs did not have a material impact on the Corporation's 2009 and 2008 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, 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 expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and Caribbean Utilities would be recognized in the current period. The loss charged to accumulated amortization in 2009 was approximately $37 million (2008 – $36 million).

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.

As required by their respective regulator, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Fortis Turks and Caicos and, commencing May 2008, Caribbean Utilities 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 2009, GEC totalled $57 million (2008 – $57 million).

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

Utility Capital Assets (cont'd)

As required by their respective regulator, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, 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 2009 was $18 million (2008 – $13 million) (Note 18), including an equity component of $9 million (2008 – $6 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

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 2009, amortization expense was reduced by $4 million (2008 – $4 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 33.3 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2009 was 3.2 per cent (2008 – 3.5 per cent). The service life ranges and average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2009		2008	
(Years)	**Service Life Ranges**	**Average Remaining Service Life**	Service Life Ranges	Average Remaining Service Life
Distribution				
Gas	**10–50**	**34**	10–50	34
Electricity	**5–75**	**26**	5–75	28
Transmission				
Gas	**10–50**	**33**	10–50	34
Electricity	**10–75**	**34**	10–75	34
Generation	**5–75**	**31**	5–75	31
Other	**5–70**	**13**	5–70	12

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. 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 recorded at cost and is amortized on a straight-line basis over a range of 2 years 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 depreciated over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangibles

Effective January 1, 2009, the Corporation retroactively adopted the new CICA Handbook Section 3064, *Goodwill and Intangible Assets.* This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. As at December 31, 2008, the impact of retroactively adopting Section 3064 was a reclassification of $264 million to intangible assets and related decreases of $262 million to utility capital assets, $1 million to income producing properties and $1 million to other assets due to the reclassification of the net book value of land, transmission and water rights, computer software costs, franchise costs, customer contracts and other costs.

Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; customer contracts; and assets under construction. Intangible assets are recorded at cost less accumulated depreciation.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful life 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 and, for non-regulated intangible assets, require the use of estimates of the useful lives of the assets.

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangibles, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, 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 expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of intangible assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of intangibles at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and Caribbean Utilities would be recognized in the current period. The loss charged to accumulated amortization in 2009 was approximately $1 million (2008 – nil).

Intangible assets with indefinite useful lives are tested for impairment annually either individually or at the reporting unit level. Such intangibles are not amortized. The useful life of 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 are being amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates range from 1.6 per cent to 20.0 per cent. The service life ranges and average remaining service life of definite life intangibles as at December 31, 2009 were as follows.

(Years)	**Service Life Ranges**	**Average Remaining Service Life**
Computer software	5–10	5
Land, transmission and water rights	15–61	37
Franchise fees, customer contracts and other	4–40	6

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 asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its 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, 2009 and 2008.

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 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 a regulated asset's 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 cash inflows for regulated enterprises are not asset-specific but are pooled for the entire regulated enterprise.

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 is 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 2009 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

December 31, 2009 and 2008

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

Goodwill (cont'd)

from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2009 and 2008.

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, 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 (loss) over 10 per cent 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, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(xi)*).

Supplementary and Other Post-Employment Benefit ("OPEB") Plans

The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits 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 its 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 (loss) over 10 per cent 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 Newfoundland Power are 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.

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 or refunded in future customer rates, is subject to deferral treatment (Note 4 *(v)*).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 16). 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, with stock option forfeitures recognized in the period incurred. 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.

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

Foreign Currency Translation

The assets and liabilities of 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, 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. The exchange rate in effect as at December 31, 2009 was US$1.00=CDN$1.05 (December 31, 2008 – US$1.00=CDN$1.22). 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 expense items 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 recorded separately 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 expense items denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recorded in earnings.

Financial Instruments

The Corporation designates its financial instruments into 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 recorded 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 recorded 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 recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded 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 treatment to be recovered from, or refunded to, customers in future rates (Note 4 *(ii)* and *(xxi)*). Generally, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

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.

Effective for the first quarter of 2009, the Corporation adopted the new Emerging Issues Committee Abstract 173 ("EIC-173"), *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. There was no material effect on the Corporation's consolidated financial statements as a result of adopting EIC-173.

Effective December 31, 2009, the Corporation adopted amendments to the CICA Handbook Section 3862, *Financial Instruments – Disclosures*, by providing additional disclosures about the fair value measurement of financial instruments and enhanced liquidity risk disclosures. The amendments establish a hierarchical disclosure framework associated with the level of pricing observability utilized in measuring fair value.

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

Financial Instruments (cont'd)

This framework defines three levels of inputs to the fair value measurement process and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the hierarchy in Section 3862 are as follows:

i) Level 1 Inputs – quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

ii) Level 2 Inputs – inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly, as prices, or indirectly, as derived from prices; and

iii) Level 3 Inputs – inputs for the asset or liability that are not based on observable market data (unobservable inputs). These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability and are developed based on the best information available in the circumstances, which might include the reporting entity's own data.

The Corporation has reflected the additional disclosures in Note 25.

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3862, *Financial Instruments – Disclosures*, and Section 3863, *Financial Instruments – Presentation*, which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The disclosures are provided in Notes 25 and 26.

Hedging Relationships

As at December 31, 2009, the Corporation's hedging relationships consisted of an interest rate swap contract, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Fortis Properties has designated its interest rate swap contract as a hedge of the cash flow risk related to floating-rate long-term debt. The interest rate swap contract is valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of the interest rate swap contract that is in an effective hedging relationship is recorded in other comprehensive income.

The foreign exchange forward contract is held by TGVI and hedges the cash flow risk related to approximately US$15 million remaining to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The fair value of the foreign exchange forward contract is calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. Any change in the fair value of the foreign exchange forward contract is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the 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 value of the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts that the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts as at the balance sheet date. As at December 31, 2009, 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

Effective January 1, 2009, Fortis retroactively recognized future income tax assets and liabilities and related regulatory liabilities and assets, without prior period restatement, for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, as at January 1, 2009, of adopting amended Section 3465, *Income Taxes*, included an increase in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items. Included in future income tax assets and liabilities recorded are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates.

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 (recovery) is recognized for the estimated income taxes payable (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 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 in rates once they become payable.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment (Note 4 *(i)*).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenue. 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 power purchase agreements.

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 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.

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 PUC, 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 is recorded on the consolidated balance sheet as a regulatory liability (Note 4 *(xviii)*).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. As stipulated by the AUC, 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 AUC-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. The rates collected are based on forecasted transmission expenses and, for certain elements

December 31, 2009 and 2008

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

Revenue Recognition (cont'd)

of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either recovered, or refunded, in future customer rates (Note 4 *(iv)*).

FortisOntario's regulated operations primarily comprise 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 are 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 recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

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 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.

No significant environmental issues have been identified with respect to the Corporation's hydroelectric generation and T&D assets. 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.

Capital Disclosures

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 1535, *Capital Disclosures*, which requires the Corporation to disclose additional information about its capital and the manner in which it is managed. The additional disclosure includes quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital. The disclosures are provided in Note 24.

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 2 under the headings Regulation, Utility Capital Assets, Income Producing Properties, Intangibles, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 4 and 28.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In October 2009, the AcSB issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011. The Corporation's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported on the Corporation's consolidated opening IFRS balance sheet as at January 1, 2010 and amounts reported by the Corporation for the year ended December 31, 2010.

In July 2009, CICA Handbook Section 1506, *Accounting Changes*, was modified such that it does not apply to changes in accounting policies upon the complete replacement of an entity's primary basis of accounting. The requirement for all publically accountable enterprises in Canada to apply IFRS, beginning January 1, 2011, represents a complete replacement of the Corporation's primary basis of accounting. CICA Handbook Section 1506, therefore, does not apply to the adoption of IFRS.

Fortis is continuing to assess the financial reporting impacts of adopting IFRS. In July 2009, the International Accounting Standards Board ("IASB") issued the Exposure Draft – *Rate-Regulated Activities*. Based on the Exposure Draft as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce the earnings' volatility at the Corporation's regulated utilities that may otherwise result under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. However, uncertainty as to the final outcome of this Exposure Draft and the final standard on accounting for rate-regulated activities under IFRS has resulted in the Corporation being unable to reasonably estimate and conclude on the impact on the Corporation's future consolidated financial position and results of operations with respect to the differences, if any, in accounting for rate-regulated activities under IFRS versus Canadian GAAP.

Fortis anticipates a change in the manner in which it will measure and recognize the value of its income producing properties and a significant increase in disclosure resulting from the adoption of IFRS. The Corporation is identifying and assessing the impact of this change in valuation and additional disclosure requirements, as well as implementing systems changes that will be necessary to compile the required disclosures.

The IASB's project schedule had indicated that a final standard on rate-regulated activities would be released in the second quarter of 2010. Commentary received on the Exposure Draft, and the resulting activities now planned by the IASB, creates uncertainty as to if and when a final standard will be released. If a final standard is released, it may not be until late 2011.

Business Combinations

In January 2009, the AcSB issued new CICA Handbook Section 1582, *Business Combinations*, together with Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-Controlling Interests*. These new standards are effective for fiscal years beginning on or after January 1, 2011 with early adoption permitted. The Corporation has chosen to early adopt the above standards as at January 1, 2010. As a result of adopting Section 1582, changes in the determination of the fair value of the assets and liabilities of the acquiree will result in a different calculation of goodwill with respect to future acquisitions. 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 will affect the recognition of business combinations completed by the Corporation on or after January 1, 2010 and, as a result, may have a material impact on the Corporation's consolidated earnings and financial position.

Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of Sections 1601 and 1602 will result 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 and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The adoption of Sections 1601 and 1602 is not expected to have a material impact on the Corporation's consolidated earnings, cash flows or financial position.

4. 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 associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

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

Based on previous, existing or expected future 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)	**2009**	2008	**Remaining recovery period *(Years)***
Future income taxes *(i)*	**$ 560**	$ –	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**82**	76	Various
Rate stabilization accounts – electric utilities *(iii)*	**68**	80	Various
AESO charges deferral *(iv)*	**80**	64	2
Regulatory OPEB plan asset *(v)*	**59**	51	To be determined
Point Lepreau [(1)] replacement energy deferral (*vi*)	**23**	-	25
Income taxes recoverable on OPEB plans *(vii)*	**18**	18	To be determined
Energy management costs *(viii)*	**9**	7	1–7
Deferred development costs for capital *(ix)*	**7**	5	1–26
Southern Crossing Pipeline tax reassessment *(x)*	**7**	7	To be determined
Deferred pension costs *(xi)*	**6**	7	6
Lease costs *(xii)*	**6**	6	14–29
Deferred capital asset amortization *(xiii)*	**4**	8	1
Residential unbundling *(xiv)*	**3**	7	1
Other regulatory assets *(xv)*	**49**	24	To be determined
Total regulatory assets	**981**	360	
Less: current portion	**(223)**	(157)	1
Long-term regulatory assets	**$ 758**	$ 203	

[(1)] New Brunswick Power Point Lepreau Nuclear Generating Station

Regulatory Liabilities

(in millions)	**2009**	2008	**Remaining settlement period *(Years)***
Future asset removal and site restoration provision *(xvi)*	**$ 326**	$ 325	To be determined
Future income taxes *(i)*	**35**	–	To be determined
Rate stabilization accounts – Terasen Gas companies *(ii)*	**44**	32	1–3
Rate stabilization accounts – electric utilities *(iii)*	**21**	9	1
PBR incentive liabilities *(xvii)*	**15**	13	1–2
Unbilled revenue liability *(xviii)*	**10**	15	To be determined
Southern Crossing Pipeline deferral *(xix)*	**9**	9	1–5
Deferred interest *(xx)*	**7**	3	1–3
Fair value of the foreign exchange forward contract *(xxi)*	**–**	7	To be determined
Other regulatory liabilities *(xxii)*	**22**	21	To be determined
Total regulatory liabilities	**489**	434	
Less: current portion	**(53)**	(45)	1
Long-term regulatory liabilities	**$ 436**	$ 389	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Future Income Taxes*

Effective January 1, 2009, Fortis retroactively recognized future income tax assets and liabilities and related regulatory liabilities and assets, without prior period restatement, for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. Included in future income tax assets and liabilities recorded 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 recorded 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 and natural gas cost volatility.

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 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 recorded 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.

TGVI also maintains 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. The additional 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 forecasted amount. The difference between the actual 2009 revenue surplus and the approved forecasted amount was transferred to the Rate Stabilization Deferral Account ("RSDA"), subject to BCUC approval. The RSA will be returned to customers equally in 2010 and 2011. The RSDA will be refunded to customers in rates in 2012 and beyond, subject to regulatory approval.

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

(in millions)	**2009**	2008
Current Regulatory Assets		
CCRA	**$ 40**	$ 54
MCRA	**29**	–
GCVA	**13**	19
RDDA	**–**	3
	$ 82	$ 76
Current Regulatory Liabilities		
RSAM	**$ 12**	$ –
RSA	**2**	–
MCRA	**–**	24
	$ 14	$ 24
Long-Term Regulatory Liabilities		
RSAM	**$ 23**	$ 8
RSA	**2**	–
RSDA	**5**	–
	$ 30	$ 8

4. Regulatory Assets and Liabilities (cont'd)

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

(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 or refunded through customer rates, as approved by the respective regulatory authority. The rate stabilization accounts primarily mitigate the effect on earnings of the 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 Newfoundland Power's year-to-year earnings volatility 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 year to five years and is subject to periodic review by the respective regulator.

The balance in Newfoundland Power's weather normalization account as at December 31, 2009 was $6 million (December 31, 2008 – $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, approximately $7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recorded 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, 2009, $10 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 five 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, 2009, the $20 million balance in Belize Electricity's rate stabilization account was in a payable position (December 31, 2008 – $9 million payable position) and was not subject to a regulatory return. In 2008, an unfavourable $18 million adjustment was made to Belize Electricity's rate stabilization account reflecting, in substance, the disallowance of previously incurred fuel and purchased power costs as a result of the Final Decision by the PUC on Belize Electricity's 2008/2009 Rate Application.

As at December 31, 2009, $6 million (December 31, 2008 – $2 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) 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. As at December 31, 2009, the AESO charges deferral account balance of $80 million is expected to be collected in customer rates in 2010 and 2011, with $20 million of the balance subject to regulatory approval. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(v) Regulatory OPEB Plan Asset

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 asset represents the deferred portion of the benefit cost at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. 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, 2009, FortisAlberta's and FortisBC's regulatory OPEB assets totalling $12 million (December 31, 2008 – $11 million) were not subject to a regulatory return.

(vi) Point Lepreau Nuclear Generating Station Replacement Energy Deferral

Maritime Electric has regulatory approval to defer the cost of replacement energy related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau") during its refurbishment outage. The station was out of service in 2009 due to the refurbishment occurring during the year. The balance in the regulatory asset account is expected to be recovered from customers over 25 years, the remaining life of the station, subject to regulatory approval. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(vii) 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. Prior to 2009, TGI accounted for income taxes using the taxes payable basis of accounting; 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.

(viii) *Energy Management Costs*
FortisBC and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. FortisBC and Maritime Electric, as required by their respective regulator, have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over seven and five years, respectively. 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.

(ix) *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 customer rates. The majority of the balance relates to costs 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 approved by the regulator was charged to earnings in 2009. In the absence of rate regulation, the deferred development costs would be capitalized; however, the ultimate period of amortization may differ.

(x) *Southern Crossing Pipeline Tax Reassessment*
The Southern Crossing Pipeline tax reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable, pending resolution of the appeal. Any final assessed tax, upon resolution of the appeal, would be expensed in the period in which it becomes known (Note 28).

(xi) *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 ten-year period that began on April 1, 2005, as ordered by the PUB. In the absence of rate regulation, these costs would have been expensed in 2005.

(xii) *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 step lease payments during the lease term; however, as ordered by the BCUC, 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 recorded in earnings on a straight-line basis over the lease term.

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

(xiii) *Deferred Capital Asset Amortization*
Newfoundland Power deferred the recovery of a $6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The amount deferred is being amortized as an increase in amortization costs and included in customer rates equally over 2008 through 2010. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(xiv) *Residential Unbundling*
Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. The remaining balance will be recovered from customers in 2010. In the absence of rate regulation, these costs would have been expensed in the period incurred.

(xv) *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, 2009, $33 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2009, $9 million (December 31, 2008 – $1 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

December 31, 2009 and 2008

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

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

(xvi) Future 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 future 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 future 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 difference 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.

During 2009, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was $29 million (2008 – $27 million). During 2009, actual asset removal and site restoration costs, net of salvage proceeds, were $23 million (2008 – $16 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 expense.

(xvii) 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 $11 million is expected to be refunded to customers during 2010 and 2011. The current portion of FortisBC's regulatory PBR incentive liability has been approved by the BCUC for settlement in 2010. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xviii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 2). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is 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 PUB. 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 PUB, Newfoundland Power amortized $5 million of this regulatory liability in 2009 (2008 – $7 million). The remaining unamortized $5 million balance as at December 31, 2009 will be amortized in 2010. In the absence of rate regulation, revenue would be 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, 2009 (December 31, 2008 – $6 million) was not subject to a regulatory return and the settlement period has not yet been determined.

(xix) 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 what has been approved in revenue requirements. The deferral is amortized over a period of five years and $2 million as at December 31, 2009 (December 31, 2008 – nil) was not subject to a regulatory return. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xx) Deferred Interest

The Terasen Gas companies have interest deferral mechanisms, as approved by the BCUC, which accumulate variances between the actual and approved interest rates associated with long-term and short-term borrowings and between the actual and forecasted 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, the actual costs would have been expensed in the period incurred.

(xxi) Fair Value of the Foreign Exchange Forward Contract

This regulatory liability captures the change in the fair value of the foreign exchange forward contract, which hedges the US dollar payments required under the LNG construction contract. As at December 31, 2009, the balance of this deferral was $0.2 million. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings in the period incurred. This regulatory deferral is not subject to a regulatory return.

(xxii) *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, 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, 2009, $10 million (December 31, 2008 – $7 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:

	Increase/(Decrease)	
(in millions)	**2009**	2008
Regulatory assets	**$ (954)**	$ (344)
Regulatory liabilities	**(489)**	(446)
Accumulated other comprehensive loss	**30**	18
Opening retained earnings	**(378)**	65
Revenue	**$ 451**	$ 609
Energy supply costs	**447**	540
Operating expense	**122**	74
Amortization expense	**(35)**	(31)
Finance charges	**(3)**	–
Corporate taxes	**7**	(11)
Net earnings	**$ (87)**	$ 37

5. Inventories

(in millions)	**2009**	2008
Gas in storage	**$ 159**	$ 212
Materials and supplies	**19**	17
	$ 178	$ 229

During 2009, inventories of $1,022 million (2008 – $1,268 million) were expensed and reported in energy supply costs in the consolidated statement of earnings. Inventories expensed to operating expenses were $14 million for 2009 (2008 – $14 million), which included $10 million for food and beverage costs at Fortis Properties (2008 – $9 million).

6. Other Assets

(in millions)	**2009**	2008
Deferred pension costs *(Note 20)*	**$ 139**	$ 128
Exploits Partnership capital assets *(Note 28)*	**–**	61
Long-term accounts receivable (due 2040)	**9**	9
Deferred recoverable and project costs	**–**	8
Corporate income tax deposit at Maritime Electric *(Note 28)*	**6**	6
Energy management loans	**4**	5
Other assets	**16**	13
	$ 174	$ 230

Energy management loans to residential and general service customers for energy-efficiency initiatives and related products are interest bearing and range in terms from one year to ten years.

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

December 31, 2009 and 2008

7. Utility Capital Assets

2009

(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,407	$ (438)	$ (182)	$ –	$ 1,787
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	(348)	(13)	–	577
Assets under construction	324	–	–	–	324
Land	87	–	–	–	87
	$ 11,412	$ (2,842)	$ (800)	$ (83)	$ 7,687

2008

(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,334	$ (415)	$ (180)	$ –	$ 1,739
Electricity	3,936	(1,051)	(490)	(87)	2,308
Transmission					
Gas	1,243	(314)	(100)	–	829
Electricity	939	(250)	(3)	–	686
Generation	957	(276)	(1)	–	680
Other	874	(335)	(13)	–	526
Assets under construction	304	–	(11)	–	293
Land	80	–	–	–	80
	$ 10,667	$ (2,641)	$ (798)	$ (87)	$ 7,141

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.

The cost of utility capital assets under capital lease as at December 31, 2009 was $57 million (December 31, 2008 – $56 million) and related accumulated amortization was $24 million (December 31, 2008 – $24 million).

8. Income Producing Properties

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**

2008

(in millions)		Cost		Accumulated Amortization		Net Book Value
Buildings	$	485	$	(51)	$	434
Equipment		55		(23)		32
Tenant inducements		24		(14)		10
Land		61		–		61
Assets under construction		3		–		3
	$	628	$	(88)	$	540

The cost of income producing property assets under capital lease as at December 31, 2009 was nil (December 31, 2008 – $1 million) and related accumulated amortization was nil (December 31, 2008 – $0.1 million).

9. Intangible Assets

2009

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	**$**	**314**	**$**	**(155)**	**$**	**159**
Land, transmission and water rights		**146**		**(37)**		**109**
Franchise fees, customer contracts and other		**16**		**(8)**		**8**
Assets under construction		**3**		**–**		**3**
	$	**479**	**$**	**(200)**	**$**	**279**

2008

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	$	302	$	(143)	$	159
Land, transmission and water rights		125		(34)		91
Franchise fees, customer contracts and other		16		(5)		11
Assets under construction		12		–		12
	$	455	$	(182)	$	273

Additions to intangible assets during 2009 were $33 million, approximately $11 million of which were developed internally. Included in cost and accumulated amortization was $15 million and $1 million, respectively, related to Algoma Power, which was acquired by the Corporation in October 2009. During 2009, fully amortized computer software of $24 million was retired, reducing cost and accumulated amortization.

Included in the cost of land, transmission and water rights as at December 31, 2009 was $66 million (December 31, 2008 – $65 million) not subject to amortization.

December 31, 2009 and 2008

10. Goodwill

(in millions)	**2009**	2008
Balance, beginning of year	**$ 1,575**	$ 1,544
Terasen Gas companies	**6**	(4)
Step acquisition of Caribbean Utilities	**1**	6
Foreign currency translation impacts	**(22)**	29
Balance, end of year	**$ 1,560**	$ 1,575

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.

During 2008, the Terasen Gas companies recognized the benefit of tax losses that related to periods prior to the Corporation's ownership of Terasen, resulting in a reduction in goodwill.

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.

11. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	**2009**	2008
Regulated Utilities			
Terasen Gas Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2008 – 10.71%)	2015–2016	**$ 275**	$ 275
Unsecured Debentures –			
6.12% weighted average fixed rate (2008 – 6.29%)	2029–2039	**1,420**	1,380
Government loan *(Note 27)*	2010	**4**	8
Obligations under capital leases	2012	**11**	10
FortisAlberta			
Senior Unsecured Debentures –			
5.74% weighted average fixed rate (2008 – 5.61%)	2014–2047	**934**	709
FortisBC			
Secured Debentures –			
9.12% weighted average fixed rate (2008 – 9.28%)	2012–2023	**40**	44
Unsecured Debentures –			
6.00% weighted average fixed rate (2008 – 6.06%)	2014–2047	**500**	445
Obligation under capital lease	2032	**26**	26
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.67% weighted average fixed rate (2008 – 7.84%)	2014–2039	**469**	409
Maritime Electric			
Secured First Mortgage Bonds –			
8.10% weighted average fixed rate (2008 – 8.10%)	2010–2038	**152**	152
FortisOntario			
Senior Unsecured Notes – 7.09% fixed rate	2018	**52**	52
Belize Electricity (Note 24)			
Secured:			
US RBTT Merchant Bank loan – 5.75% to 8.15% fixed rate	2010–2012	**2**	5
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate (2008 – 10.35%)	2012–2027	**36**	42
Other loans – 5.23% weighted average fixed rate (2008 – 5.81%)	2015	**7**	11
Other variable interest rate loans	2010–2015	**13**	18

(in millions)	Maturity Date	**2009**	2008
Caribbean Utilities			
US Unsecured Senior Loan Notes –			
6.31% weighted average fixed rate (2008 – 6.04%)	2010–2024	**$ 203**	$ 204
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. loan –			
3.90% weighted average fixed and variable rate (2008 – 3.91%)	2013–2016	**10**	14
US First Caribbean International Bank loan – 5.65% fixed rate	2015	**3**	4
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**4**	5
Exploits Partnership term loan – 7.55% fixed rate			
(non-recourse to Fortis) *(Note 28)*	2028	**–**	61
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
6.89% weighted average fixed rate (2008 – 7.02%)	2010–2017	**193**	212
Senior notes – 7.32% fixed rate	2019	**15**	16
Unsecured:			
Non-revolving variable interest rate credit facilities	2010	**3**	7
Corporate – Fortis and Terasen			
Unsecured:			
Debentures –			
6.44% weighted average fixed rate (2008 – 6.37%)	2010–2039	**426**	226
US Senior Notes –			
6.23% weighted average fixed rate (2008 – 6.23%)	2014–2037	**368**	426
US Subordinated Convertible Debentures –			
5.50% weighted average fixed rate (2008 – 5.50%)	2016	**39**	44
Capital Securities – 8.00% fixed rate	2040	**126**	129
Long-term classification of credit facility borrowings *(Note 26)*		**208**	224
Total long-term debt and capital lease obligations		**5,539**	5,158
Less: Deferred financing costs		**(39)**	(34)
Less: Current installments of long-term debt and capital lease obligations		**(224)**	(240)
		$ 5,276	$ 4,884

Certain of the long-term debt instruments held by the Corporation and its subsidiaries are secured, as identified in the table above. When security is provided, it is typically a fixed or floating 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 used is limited to $425 million.

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	$ millions
2010	224
2011	53
2012	263
2013	99
2014	702
Thereafter	4,198

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

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 8.61 per cent.

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.

Corporate – Fortis and Terasen

Of the unsecured debentures, $100 million and $200 million are redeemable at the option of Fortis at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Government of Canada Bond Yield, plus a premium ranging from 0.43% to 0.87%, and 0.65%, respectively, together with accrued and unpaid interest.

The unsecured 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 $30.59 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.

The unsecured 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, 2009 (December 31, 2008 – $6 million).

Terasen may elect to defer payment on the 8.00% capital securities and settle such deferred payments in either cash or common shares of the Company and has the option to settle principal at maturity through the issuance of common shares of the Company. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash at par as of the same date.

12. Deferred Credits

(in millions)	**2009**	2008
OPEB plan liabilities *(Note 20)*	**$ 145**	$ 129
Defined benefit liabilities *(Note 20)*	**34**	34
Deferred gains on the sale of natural gas transmission and distribution assets	**42**	46
Deferred payment	**46**	43
Other deferred credits	**28**	25
	$ 295	$ 277

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 27.

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, 2009, its present value was $46 million (December 31, 2008 – $43 million). 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 deferred credits primarily include customer deposits, funds received in advance of expenditures, DSU and PSU liabilities (Note 16), and unfunded defined contribution pension liabilities. 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 earnings.

13. Non-Controlling Interest

(in millions)	2009	2008
Caribbean Utilities	**$ 77**	$ 92
Belize Electricity	**39**	44
Preference shares of Newfoundland Power	**7**	7
Exploits Partnership *(Note 28)*	**–**	2
	$ 123	$ 145

14. 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		**2009**		2008	
	Classification	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
First Preference Shares, Series C	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
First Preference Shares, Series E	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt		**12,993,500**	**$ 320**	12,993,500	$ 320
First Preference Shares, Series F	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122
First Preference Shares, Series G	Equity	**9,200,000**	**225**	9,200,000	225
Total classified as equity		**14,200,000**	**$ 347**	14,200,000	$ 347

First Preference Shares Classified as Debt

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.

The First Preference Shares, Series C and Series E are entitled to receive fixed cumulative preferential cash dividends at rates of $1.3625 and $1.2250 per share per annum, respectively.

On or after June 1, 2010 and 2013, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series C and Series E, respectively, in whole at any time or in part from time to time, at prices ranging from $25.75 to $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

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 tradable 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 per cent of the then-current market price of the common shares at such time.

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 tradable 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 per cent 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 for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares Classified as Equity

In May 2008, the Corporation issued 8 million 5.25% Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") and in June 2008 issued an additional 1.2 million First Preference Shares, Series G, following the exercise in full of an over-allotment option in connection with the offering of the 8 million First Preference Shares, Series G. The 9.2 million First Preference Shares, Series G were issued at $25.00 per share for net after-tax proceeds of $225 million.

December 31, 2009 and 2008

14. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

As the First Preference Shares, Series F and Series G 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 immediately before arriving at net earnings applicable to common shares.

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.2250 per share per annum. The First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after this date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%.

On or after December 1, 2011, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series F, in whole at any time or in part from time to time, at prices ranging from $26.00 to $25.00 per share plus all accrued and unpaid dividends. On September 1, 2013 and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time or in part from time to time, at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

15. Common Shares

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

Issued and Outstanding	**2009**		2008	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Common shares	**171,256,432**	**$ 2,497**	169,190,917	$ 2,449

Common shares issued during the year were as follows:

Issued and Outstanding	**2009**		2008	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Balance, beginning of year	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126
Public offering	**–**	**–**	11,700,000	291
Conversion of debentures	**–**	**–**	1,041,871	11
Consumer Share Purchase Plan	**56,648**	**2**	88,686	2
Dividend Reinvestment Plan	**1,203,661**	**29**	230,601	6
Employee Share Purchase Plan	**321,081**	**8**	272,095	7
Stock Option Plans	**484,125**	**9**	336,351	6
Balance, end of year	**171,256,432**	**$ 2,497**	169,190,917	$ 2,449

In December 2008, Fortis issued 11.7 million common shares for $25.65 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses.

During 2008, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$11 million of the debentures into approximately 1 million common shares of the Corporation.

As at December 31, 2009, 7.2 million (December 31, 2008 – 9.8 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. The Corporation amended and restated its Dividend Reinvestment Plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2009, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26 million, respectively (December 31, 2008 – 1.4 million and 26 million, respectively).

As at December 31, 2009, $3 million (December 31, 2008 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 170.2 million for 2009 and 157.4 million for 2008.

Diluted earnings per common share are calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

Earnings per common share were as follows:

	2009			2008		
	Earnings *(in millions)*	**Weighted Average Shares** *(in millions)*	**Earnings per Common Share**	Earnings *(in millions)*	Weighted Average Shares *(in millions)*	Earnings per Common Share
Basic Earnings per Common Share	**$ 262**	**170.2**	**$ 1.54**	$ 245	157.4	$ 1.56
Effect of Potential Dilutive Securities:						
Stock Options	**–**	**0.7**		–	1.0	
Preference Shares *(Notes 14 and 18)*	**17**	**13.9**		17	13.9	
Convertible Debentures	**2**	**1.4**		2	1.4	
	281	**186.2**		264	173.7	
Deduct Anti-Dilutive Impacts:						
Convertible Debentures	**(2)**	**(1.4)**		–	–	
Diluted Earnings per Common Share	**$ 279**	**184.8**	**$ 1.51**	$ 264	173.7	$ 1.52

16. 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, 2009, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options 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 are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted 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	**2009**	2008
Options outstanding, beginning of year	**4,140,462**	3,691,771
Granted	**1,037,156**	827,504
Cancelled	**–**	(42,462)
Exercised	**(484,125)**	(336,351)
Options outstanding, end of year	**4,693,493**	4,140,462
Options vested, end of year	**2,546,159**	2,279,240
Weighted Average Exercise Prices		
Options outstanding, beginning of year	**$ 21.04**	$ 18.86
Granted	**22.29**	28.27
Cancelled	**–**	24.20
Exercised	**16.08**	14.48
Options outstanding, end of year	**21.83**	21.04

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

Stock Options (cont'd)

Details of stock options outstanding and vested as at December 31, 2009 were as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
81,368	81,368	$ 9.57	2011
135,726	135,726	$ 12.03	2012
341,320	341,320	$ 12.81	2013
479,484	479,484	$ 15.28	2014
10,000	10,000	$ 15.23	2014
17,011	17,011	$ 14.55	2014
508,367	508,367	$ 18.40	2015
28,000	28,000	$ 18.11	2015
14,708	14,708	$ 20.82	2015
491,937	359,805	$ 22.94	2016
596,232	298,116	$ 28.19	2014
136,832	68,416	$ 25.76	2014
815,352	203,838	$ 28.27	2015
1,037,156	–	$ 22.29	2016
4,693,493	2,546,159		

The weighted average exercise price of stock options vested as at December 31, 2009 was $19.19.

In March 2009, the Corporation granted 1,037,156 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $22.29 immediately preceding the date of grant. The fair value of each option granted was $4.10 per option.

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

Dividend yield *(%)*	3.19
Expected volatility *(%)*	24.3
Risk-free interest rate *(%)*	3.75
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 $3 million for the year ended December 31, 2009 (2008 – $3 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit for their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. 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.

Number of DSUs	**2009**	2008
DSUs outstanding, beginning of year	**100,617**	69,722
Granted	**30,336**	27,224
Granted – notional dividends reinvested	**5,375**	3,671
DSUs paid out	**(19,424)**	–
DSUs outstanding, end of year	**116,904**	100,617

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, for a total of approximately $0.5 million.

For the year ended December 31, 2009, expense of $0.9 million (2008 – $0.2 million) was recorded in relation to the DSU Plan.

PSU Plan

In 2004, the Corporation introduced the PSU Plan, which 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.

Number of PSUs	**2009**	2008
PSUs outstanding, beginning of year	**85,547**	67,615
Granted	**40,000**	32,940
Granted – notional dividends reinvested	**3,939**	3,011
PSUs paid out	**(31,353)**	(18,019)
PSUs outstanding, end of year	**98,133**	85,547

In March 2009, 31,353 PSUs at $23.39 per PSU for a total of approximately $0.7 million were paid out to the President and CEO of the Corporation. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2006 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, 2009, expense of $0.9 million (2008 – $0.6 million) was recorded in relation to the PSU Plan.

17. 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 2.

	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)**

	2008		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	$ (82)	$ 36	$ (46)
Losses 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	$ (88)	$ 36	$ (52)

During 2009, unrealized foreign currency translation losses of $90 million (2008 – gains of $115 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 $58 million (2008 – after-tax losses of $79 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.

December 31, 2009 and 2008

18. Finance Charges

(in millions)	2009	2008
Interest – Long-term debt and capital lease obligations	**$ 351**	$ 336
– Short-term borrowings	**10**	25
AFUDC *(Note 2)*	**(18)**	(13)
Interest earned	**–**	(2)
Dividends on preference shares *(Notes 14 and 15)*	**17**	17
	$ 360	$ 363

19. Corporate Taxes

Prior to January 1, 2009, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power used the taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, as at January 1, 2009, of adopting amended Section 3465, *Income Taxes*, included an increase in total future income tax liabilities and total future income tax assets of $491 million and $24 million, respectively; an increase in regulatory assets and regulatory liabilities of $535 million and $59 million, respectively; and a combined $9 million net increase in income taxes payable, deferred credits, other assets, utility capital assets and goodwill associated with the reclassification of future income taxes that were previously netted against these respective balance sheet items. Included in future income tax assets and liabilities recorded are the future income tax effects of the subsequent settlement of related regulatory assets and liabilities through customer rates.

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

(in millions)	2009	2008
Future income tax liability (asset)		
Utility capital assets	**$ 514**	$ 17
Income producing properties	**26**	26
Regulatory assets	**40**	35
Intangible assets	**8**	3
Other assets	**25**	2
Deferred credits	**(30)**	(14)
Loss carryforwards	**(31)**	(28)
Share issue and debt financing costs	**(2)**	(14)
Unrealized foreign currency translation gains (losses) on long-term debt	**5**	(5)
Regulatory liabilities	**(1)**	–
Net future income tax liability	**$ 554**	$ 22
Current future income tax asset	**$ (29)**	$ –
Current future income tax liability	**24**	15
Long-term future income tax asset	**(17)**	(54)
Long-term future income tax liability	**576**	61
Net future income tax liability	**$ 554**	$ 22

The adoption of amended Section 3465, *Income Taxes*, on January 1, 2009 also resulted in additional future income tax expense of $38 million for the year ended December 31, 2009 and an offsetting regulatory adjustment to future income tax expense of the same amount during the year. The regulatory adjustment represents the difference between the future income tax expense recognized under amended Section 3465 and that recovered from customers in rates during the year ended December 31, 2009.

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

(in millions)	**2009**	2008
Canadian		
Current taxes	**$ 43**	$ 47
Future income taxes	**42**	16
Less regulatory adjustment	**(38)**	–
	4	16
Total Canadian	**47**	63
Foreign		
Current taxes	**1**	4
Future income taxes	**1**	(2)
Total Foreign	**2**	2
Corporate taxes	**$ 49**	$ 65

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 and non-controlling interest. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2009**	2008
Combined Canadian federal and provincial statutory income tax rate	**33.0%**	33.5%
Statutory income tax rate applied to earnings before corporate taxes and non-controlling interest	**113**	113
Preference share dividends	**6**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(16)**	(12)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(8)**	(6)
Items capitalized for accounting purposes but expensed for income tax purposes	**(38)**	(33)
Difference between capital cost allowance and amounts claimed for accounting purposes	**1**	5
Québec Tax Trust settlement – Terasen [(1)]	**–**	(7)
Pension costs	**(1)**	(2)
Other	**(8)**	1
Corporate taxes	**49**	65
Effective tax rate	**14.4%**	19.3%

[(1)] During 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures. As a result of the settlement, Terasen recorded an approximate $7.5 million tax reduction in 2008.

As at December 31, 2009, the Corporation had approximately $122 million (December 31, 2008 – $112 million) in non-capital and capital loss carryforwards, of which $16 million (December 31, 2008 – $15 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2029.

20. 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, 2007 for FortisAlberta and FortisBC; as of December 31, 2006 for FortisOntario; as of December 31, 2008 for the Corporation, Newfoundland Power and Caribbean Utilities; and as of July 1, 2009 for Algoma Power. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were May 17, 2007 and December 31, 2007. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each plan.

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

Plan assets as at December 31 *(%)*	**2009**	2008
Canadian equities	**47**	42
Fixed income	**39**	44
Foreign equities	**9**	8
Real estate	**5**	6
	100	100

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

	2009			2008		
(in millions)	**Accrued Benefit Obligation**	**Plan Assets**	**Net Funded (Unfunded)**	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	**$ 282**	**$ 257**	**$ (25)**	$ 253	$ 227	$ (26)
FortisAlberta	**23**	**19**	**(4)**	22	18	(4)
FortisBC	**127**	**100**	**(27)**	117	96	(21)
Newfoundland Power	**222**	**243**	**21**	190	212	22
FortisOntario[(1)]	**21**	**20**	**(1)**	21	19	(2)
Algoma Power	**17**	**15**	**(2)**	–	–	–
Caribbean Utilities	**5**	**3**	**(2)**	6	3	(3)
Fortis	**4**	**4**	**–**	4	4	–
Total	**$ 701**	**$ 661**	**$ (40)**	$ 613	$ 579	$ (34)

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

(in millions)	Defined Benefit Pension Plans Funded 2009	Defined Benefit Pension Plans Funded 2008	Supplementary Defined Benefit Plans Unfunded 2009	Supplementary Defined Benefit Plans Unfunded 2008	OPEB Plans Unfunded 2009	OPEB Plans Unfunded 2008
Change in accrued benefit obligation						
Balance, beginning of year	**$ 613**	$ 667	**$ 41**	$ 44	**$ 169**	$ 189
Liability associated with acquisitions	**17**	–	**–**	–	**4**	–
Current service costs	**11**	16	**1**	1	**4**	4
Employee contributions	**9**	8	**–**	–	**–**	–
Interest costs	**40**	36	**2**	2	**11**	10
Benefits paid	**(34)**	(32)	**(2)**	(2)	**(4)**	(4)
Actuarial loss (gain)	**45**	(80)	**2**	(4)	**16**	(30)
Past service costs/plan amendments	**–**	(2)	**–**	–	**(17)**	–
Balance, end of year	**$ 701**	$ 613	**$ 44**	$ 41	**$ 183**	$ 169
Change in value of plan assets						
Balance, beginning of year	**$ 579**	$ 674	**$ –**	$ –	**$ –**	$ –
Assets associated with acquisitions	**15**	–	**–**	–	**–**	–
Actual return (loss) on plan assets	**71**	(92)	**–**	–	**–**	–
Benefits paid	**(34)**	(32)	**(2)**	(2)	**(4)**	(4)
Employee contributions	**9**	8	**–**	–	**–**	–
Employer contributions	**21**	21	**2**	2	**4**	4
Balance, end of year	**$ 661**	$ 579	**$ –**	$ –	**$ –**	$ –
Funded status						
Deficit, end of year	**$ (40)**	$ (34)	**$ (44)**	$ (41)	**$ (183)**	$ (169)
Unamortized net actuarial loss (gain)	**172**	152	**1**	(1)	**40**	26
Unamortized past service costs	**6**	7	**1**	1	**(17)**	(1)
Unamortized transitional obligation	**7**	7	**1**	2	**15**	15
Employer contributions after measurement date	**1**	1	**–**	–	**–**	–
Accrued benefit asset (liability), end of year	**$ 146**	$ 133	**$ (41)**	$ (39)	**$ (145)**	$ (129)
Deferred pension costs *(Note 6)*	**$ 147**	$ 135	**$ (8)**	$ (7)	**$ –**	$ –
Defined benefit liabilities *(Note 12)*	**(1)**	(2)	**(33)**	(32)	**–**	–
OPEB plan liabilities *(Note 12)*	**–**	–	**–**	–	**(145)**	(129)
	$ 146	$ 133	**$ (41)**	$ (39)	**$ (145)**	$ (129)
Significant assumptions						
Weighted average discount rate during the year *(%)*	**6.62**	5.37	**6.65**	5.35	**6.72**	5.39
Weighted average discount rate as at December 31 *(%)*	**6.16**	6.62	**6.19**	6.65	**6.27**	6.72
Weighted average expected long-term rate of return on plan assets *(%)*	**7.05**	7.24	**–**	–	**–**	–
Weighted average rate of compensation increase *(%)*	**3.60**	3.60	**3.52**	3.48	**3.68**	3.63
Weighted average health-care cost trend increase as at December 31 *(%)*	**–**	–	**–**	–	**6.34**	6.58
Expected average remaining service life of active employees *(years)*	**4–15**	5–12	**3–11**	4–12	**9–17**	9–15

December 31, 2009 and 2008

20. Employee Future Benefits (cont'd)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2009**	2008	**2009**	2008	**2009**	2008
Components of net benefit cost						
Current service costs	**$ 11**	$ 16	**$ 1**	$ 1	**$ 4**	$ 4
Interest costs	**40**	36	**2**	2	**11**	10
Actual (return) loss on plan assets	**(71)**	92	**–**	–	**–**	–
Actuarial loss (gain)	**45**	(80)	**2**	(4)	**16**	(30)
Past service costs/plan amendments	**–**	(2)	**–**	–	**(17)**	–
Costs arising in the year	**25**	62	**5**	(1)	**14**	(16)
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**25**	(141)	–	–	**–**	–
Actuarial (loss) gain	**(42)**	84	**(2)**	4	**(14)**	34
Past service costs	**1**	3	**–**	1	**16**	–
Transitional obligation and plan amendments	**–**	–	**1**	–	**2**	3
Regulatory adjustment	**1**	1	**–**	–	**(6)**	(7)
Net benefit cost	**$ 10**	$ 9	**$ 4**	$ 4	**$ 12**	$ 14

For 2009, the effects of changing the health-care cost trend rate by 1 per cent were as follows:

(in millions)	**1 per cent increase in rate**	**1 per cent decrease in rate**
Increase (decrease) in accrued benefit obligation	**$ 22**	**$ (19)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2009 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.

Increase (Decrease) *(in millions)*	**Net Benefit Cost**	**Accrued Benefit Asset**	**Accrued Benefit Liability**	**Accrued Benefit Obligation**
Impact of increasing the rate of return assumption by 100 basis points	**$ (7)**	**$ 7**	**$ –**	**$ –**
Impact of decreasing the rate of return assumption by 100 basis points	**7**	**(7)**	**–**	**–**
Impact of increasing the discount rate assumption by 100 basis points	**(3)**	**2**	**(1)**	**(73)**
Impact of decreasing the discount rate assumption by 100 basis points	**6**	**(4)**	**1**	**86**

During 2009, the Corporation expensed $12 million (2008 – $11 million) related to defined contribution pension plans.

21. 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**

2008

NON-REGULATED FORTIS PROPERTIES

Sheraton Hotel Newfoundland

In November 2008, Fortis Properties purchased the Sheraton Hotel Newfoundland for an aggregate cash purchase price of approximately $22 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 November 2008.

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	$ 22

December 31, 2009 and 2008

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2009 *($ millions)*	**Terasen Gas Companies – Canadian**	Fortis Alberta	Fortis BC	NF Power	Other Canadian(1)	**Total Electric Canadian**	**Electric Caribbean(2)**	**Fortis Generation(3)**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	1,663	331	253	527	279	1,390	339	39	218	27	(39)	3,637
Energy supply costs	1,022	–	72	346	183	601	192	2	–	–	(18)	1,799
Operating expenses	268	132	70	52	32	286	54	11	146	14	(6)	773
Amortization	102	94	37	46	19	196	37	5	16	8	–	364
Operating income	271	105	74	83	45	307	56	21	56	5	(15)	701
Finance charges	121	50	32	34	19	135	16	2	22	79	(15)	360
Corporate taxes (recoveries)	33	(5)	5	16	6	22	2	3	10	(21)	–	49
Non-controlling interest	–	–	–	1	–	1	11	–	–	–	–	12
Net earnings (loss)	117	60	37	32	20	149	27	16	24	(53)	–	280
Preference share dividends	–	–	–	–	–	–	–	–	–	18	–	18
Net earnings (loss) applicable to common shares	117	60	37	32	20	149	27	16	24	(71)	–	262
Goodwill	908	227	221	–	63	511	141	–	–	–	–	1,560
Identifiable assets	4,084	1,892	1,141	1,188	631	4,852	799	252	576	130	(93)	10,600
Total assets	4,992	2,119	1,362	1,188	694	5,363	940	252	576	130	(93)	12,160
Gross capital expenditures(4)	246	407	115	74	46	642	92	14	26	4	–	1,024
Year ended December 31, 2008 *($ millions)*												
Revenue	1,902	300	237	517	262	1,316	408	82	207	26	(38)	3,903
Energy supply costs	1,268	–	68	337	177	582	273	7	–	–	(18)	2,112
Operating expenses	253	130	67	50	28	275	55	14	135	16	(5)	743
Amortization	97	85	34	45	18	182	36	10	15	8	–	348
Operating income	284	85	68	85	39	277	44	51	57	2	(15)	700
Finance charges	129	42	28	33	18	121	16	8	24	80	(15)	363
Corporate taxes (recoveries)	37	(3)	6	19	7	29	2	10	10	(23)	–	65
Non-controlling interest	–	–	–	1	–	1	9	3	–	–	–	13
Net earnings (loss)	118	46	34	32	14	126	17	30	23	(55)	–	259
Preference share dividends	–	–	–	–	–	–	–	–	–	14	–	14
Net earnings (loss) applicable to common shares	118	46	34	32	14	126	17	30	23	(69)	–	245
Goodwill	903	227	221	–	63	511	161	–	–	–	–	1,575
Identifiable assets	3,721	1,574	978	1,001	520	4,073	867	285	559	126	(40)	9,591
Total assets	4,624	1,801	1,199	1,001	583	4,584	1,028	285	559	126	(40)	11,166
Gross capital expenditures(4)	220	333	117	67	46	563	110	19	14	9	–	935

(1) Includes Maritime Electric and FortisOntario. FortisOntario includes Algoma Power from October 2009.

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

(3) Results for 2009 reflected 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.

(4) Related to utility capital assets, including amounts for AESO transmission capital projects, income producing properties and intangible assets

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)	**2009**	2008
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ 17**	$ 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**	2
Corporate to Regulated Electric Utilities – Caribbean	**6**	5
Corporate to Fortis Properties	**8**	8

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2009**	2008
Interest paid	**$ 378**	$ 380
Income taxes paid	**85**	33

24. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital in order 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 with proceeds from common and preference share issuances. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent 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, 2009 compared to December 31, 2008 is presented in the following table.

	2009		2008	
	(in millions)	*(%)*	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash)[(1)]	**$ 5,830**	**60.2**	$ 5,468	59.5
Preference shares[(2)]	**667**	**6.9**	667	7.3
Common shareholders' equity	**3,193**	**32.9**	3,046	33.2
Total	**$ 9,690**	**100.0**	$ 9,181	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

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at December 31, 2009, 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 $7 million (BZ$12 million) as at December 31, 2009. The Company has informed the lenders of the defaults and has requested appropriate waivers.

December 31, 2009 and 2008

24. Capital Management (cont'd)

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 $59 million as at December 31, 2009 (December 31, 2008 – $61 million). The lenders of the term loan have not demanded accelerated repayment. See Note 28 for further information on the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 26.

25. Financial Instruments

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

	As at December 31, 2009		As at December 31, 2008	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents[(1)]	**$ 85**	**$ 85**	$ 66	$ 66
Loans and receivables				
Trade and other accounts receivable[(1)(2)(3)]	**595**	**595**	674	674
Other receivables due from customers[(1)(3)(4)]	**7**	**7**	8	8
Other financial liabilities				
Short-term borrowings[(1)(3)]	**415**	**415**	410	410
Trade and other accounts payable[(1)(3)(5)]	**730**	**730**	782	782
Dividends payable[(1)(3)]	**3**	**3**	47	47
Customer deposits[(1)(3)(6)]	**7**	**7**	6	6
Long-term debt, including current portion[(7)(8)]	**5,502**	**5,906**	5,122	5,040
Preference shares, classified as debt[(7)(9)]	**320**	**348**	320	329

(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 deferred credits on the consolidated balance sheet

(7) Carrying value is measured at amortized cost using the effective interest rate method.

(8) Carrying value as at December 31, 2009 excludes unamortized deferred financing costs of $39 million (December 31, 2008 – $34 million) and capital lease obligations of $37 million (December 31, 2008 – $36 million).

(9) 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 $347 million preference shares classified as equity was $356 million as at December 31, 2009 (December 31, 2008 – carrying value of $347 million; fair value of $268 million).

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

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.

	2009				2008	
Asset (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)*
Interest rate swaps[(1)(2)]	**1**	**1**	**$ –**	**$ –**	$ –	$ –
Foreign exchange forward contract[(3)(4)]	**< 2**	**1**	**–**	**–**	7	7
Natural gas derivatives:[(2)(5)]						
Swaps and options	**Up to 5**	**223**	**(119)**	**(119)**	(84)	(84)
Gas purchase contract premiums	**Up to 2**	**69**	**(3)**	**(3)**	(8)	(8)

[(1)] The interest rate swap contract matures in October 2010. The contract has the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 5.32 per cent.

[(2)] The fair value measurements are Level 1, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.

[(3)] The fair value measurement is Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.

[(4)] The fair value of the foreign exchange forward contract was recorded in accounts receivable as at December 31, 2009 and 2008.

[(5)] The fair value of the natural gas derivatives was recorded in accounts payable as at December 31, 2009 and 2008.

The fair value of the Corporation's financial instruments, including derivatives, reflects 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 earnings or cash flows.

26. 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 receivables due from customers, 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 and 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, and as at December 31, 2009 its gross credit risk exposure was approximately $90 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or 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. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. 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.

The aging analysis of the Corporation's consolidated trade and other accounts receivable, net of an allowance for doubtful accounts of $17 million as at December 31, 2009 (December 31, 2008 – $16 million), excluding derivative financial instruments recorded in accounts receivable, was as follows:

December 31, 2009 and 2008

26. Financial Risk Management (cont'd)

(in millions)	**As at December 31, 2009**	As at December 31, 2008
Not past due	**$ 527**	$ 585
Past due 0–30 days	**52**	68
Past due 31–60 days	**8**	13
Past due 61 days and over	**8**	8
	$ 595	$ 674

As at December 31, 2009, other receivables due from customers of $7 million (included in other assets) will be received over the next five years and thereafter, with $2 million expected to be received in 2010, $3 million over 2011 and 2012, $1 million over 2013 and 2014 and $1 million due after 2014.

Liquidity Risk

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

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

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $270 million. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2009, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 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 per cent 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, 2009**	Total as at December 31, 2008
Total credit facilities	$ 645	$ 1,495	$ 13	**$ 2,153**	$ 2,228
Credit facilities utilized:					
Short-term borrowings	–	(409)	(6)	**(415)**	(410)
Long-term debt *(Note 11)*[(1)]	(125)	(83)	–	**(208)**	(224)
Letters of credit outstanding	(1)	(98)	(1)	**(100)**	(104)
Credit facilities unused	$ 519	$ 905	$ 6	**$ 1,430**	$ 1,490

[(1)] As at December 31, 2009, credit facility borrowings classified as long-term debt included $13 million (December 31, 2008 – $8 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at December 31, 2009 and 2008, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other
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 $350 million unsecured committed revolving credit facility, maturing January 2011. 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 2012 and the remaining $100 million matures May 2010. 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 2011, and a $20 million demand credit facility.

Maritime Electric has a $50 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 ($34 million), comprised of a capital expenditure line of credit of US$18 million ($19 million), including amounts available for letters of credit, a US$7.5 million ($8 million) operating line of credit and a US$7.5 million ($8 million) catastrophe standby loan.

Fortis Turks and Caicos has unsecured credit facilities of US$21 million ($22 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 ($9.5 million) emergency standby loan.

Belize Electricity has an unsecured BZ$2 million ($1 million) and a secured BZ$5 million ($3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank, respectively.

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

Furthermore, 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, 2009, the Corporation's credit ratings were as follows:

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

The credit ratings reflect the diversity of the operations of Fortis, 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 continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

December 31, 2009 and 2008

26. Financial Risk Management (cont'd)

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2009.

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	$ 415	$ –	$ –	$ –	**$ 415**
Trade and other accounts payable	730	–	–	–	**730**
Natural gas derivatives[(1)]	81	31	5	–	**117**
Foreign exchange forward contract[(2)]	14	1	–	–	**15**
Dividends payable	3	–	–	–	**3**
Customer deposits[(3)]	2	2	1	2	**7**
Long-term debt, including current portion[(4)]	222	312	797	4,171	**5,502**
Interest obligations on long-term debt	346	667	641	4,972	**6,626**
Preference shares, classified as debt	–	–	123	197	**320**
Dividend obligations on preference shares, classified as interest expense	17	33	24	16	**90**
	$ 1,830	$ 1,046	$ 1,591	$ 9,358	**$ 13,825**

(1) Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2009 at $122 million.

(2) Amounts disclosed are on a gross cash flow basis. The contract was recorded in accounts receivable at fair value as at December 31, 2009 at $0.2 million.

(3) Customer deposits were recorded in deferred credits as at December 31, 2009.

(4) Excludes deferred financing costs of $39 million and capital lease obligations of $37 million

Market Risk

Foreign Exchange Risk

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, 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, 2009, the Corporation's corporately held US$390 million (December 31, 2008 – US$403 million) long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2009, the Corporation had approximately US$174 million (December 31, 2008 – US$119 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 per cent appreciation or depreciation of the US dollar relative to the Canadian dollar would have increased or decreased earnings by approximately $1 million for the year ended December 31, 2009 (2008 – $0.6 million) and would have decreased or increased other comprehensive income by $20 million for the year ended December 31, 2009 (2008 – $25 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 per cent 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 $31 million for the year ended December 31, 2009 (2008 – $32 million).

TGVI's US dollar payments under a contract for the construction of an LNG storage facility expose TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2009, a 5 per cent 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 contract, in the absence of rate regulation and with all other variables remaining constant, would have increased or decreased earnings by $1 million for the year ended December 31, 2009 (2008 – $3 million). Furthermore, TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Interest Rate Risk
The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt.

The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk and, during 2009, Fortis Properties was party to two interest rate swap agreements that effectively fixed the interest rates on its variable-rate borrowings. During the third quarter of 2009, one of Fortis Properties' interest rate swaps 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, 2009 (2008 – $5 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, 2009 (2008 – $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.

As at December 31, 2009, a 100 basis point increase or decrease in interest rates as it affects the measurement of the fair value of the interest rate swap agreement would have had no effect on other comprehensive income for the year ended December 31, 2009 (2008 – increased or decreased other comprehensive income by $0.1 million).

In addition, 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, 2009 (2008 – $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 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. 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.

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 $81 million for the year ended December 31, 2009 (2008 – $54 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 $81 million (December 31, 2008 – $54 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 $82 million for the year ended December 31, 2009 (2008 – $52 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $82 million (December 31, 2008 – $52 million).

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

December 31, 2009 and 2008

27. 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)]	**$ 746**	$ 387	$ 193	$ 166	$ –
Power purchase obligations					
FortisBC[(2)]	**2,921**	42	83	78	2,718
FortisOntario[(3)]	**509**	46	95	99	269
Maritime Electric[(4)]	**66**	47	2	2	15
Belize Electricity[(5)]	**327**	26	65	69	167
Capital cost[(6)]	**383**	15	40	42	286
Joint-use asset and shared service agreements[(7)]	**62**	4	6	6	46
Office lease – FortisBC[(8)]	**19**	1	4	3	11
Operating lease obligations[(9)]	**147**	17	31	27	72
Equipment purchase – Fortis Turks and Caicos[(10)]	**12**	8	4	–	–
Other	**30**	12	12	5	1
Total	**$ 5,222**	$ 605	$ 535	$ 497	$ 3,585

(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, 2009.

(2) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA"), as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant 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 power purchase agreement 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.

(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. The take-or-pay contract with NB Power includes, among other things, replacement energy and capacity for Point Lepreau during its refurbishment outage and the contract expires in December 2010. 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 power purchase agreement, 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 power purchase agreements 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.

In October 2009, the Comisión Federal de Electricidad of Mexico cancelled the guaranteed power supply contract for firm energy with Belize Electricity, citing force majeure reasons. The contract was to mature in December 2010.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from Point Lepreau 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.

(7) 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 contract, the calculation of future payments after 2014 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, 2005 and are subject to extension based on mutually agreeable terms.

(8) 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.

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

(10) Fortis Turks and Caicos has entered into an agreement with a supplier to purchase two diesel-powered generating units with a combined capacity of approximately 18 MW for delivery in mid-2010 and early 2011.

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 forecasted to be approximately $1.1 billion for 2010, 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 is expected to make a $4 million repayment on the loans in 2010 (2009 – $8 million). As at December 31, 2009, the outstanding balance of the repayable government loans was $53 million, with $4 million classified as current portion of long-term debt. Timing of the repayments of the government loans beyond 2010 are dependent upon the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms. TGVI, however, estimates making payments under the loans of $20 million in 2012, $14 million over 2013 and 2014 and $15 million thereafter.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The contract is for three years terminating in April 2010, with 9 million imperial gallons required to be purchased during 2010. 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.

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.

Consolidated defined benefit pension funding contributions, including current service, solvency and special funding amounts, are expected to be $20 million in 2010, $8 million in 2011, $4 million in 2012 and $3 million in 2013. The contributions, however, 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 as follows for the larger defined benefit pension plans:

December 31, 2009 – Terasen (covering non-unionized employees)
December 31, 2010 – Terasen (covering unionized employees) and FortisBC
December 31, 2011 – Newfoundland Power

28. 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

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset (Note 4 *(x)*). TGI was successful in its appeal to the Supreme Court of British Columbia in June 2009. The Province of British Columbia has been granted leave to appeal the decision to the British Columbia Court of Appeal.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

On July 16, 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 a pipeline rupture in July 2007. Terasen has filed a statement of defence but the claim is in its early stages and the amount and outcome of it is indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

In 2008, the Vancouver Island Gas Joint Venture ("VIGJV") commenced a lawsuit against TGVI seeking damages for alleged overpayments of past tolls and declarations for reduction of its future tolls. The Statement of Claim did not quantify damages and the case did not reach the stage where either party formally quantified VIGJV's claims. In December 2009, VIGJV abandoned its claim and in January 2010, the lawsuit was dismissed by consent dismissal order. The matter is now fully concluded.

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. The Company is communicating with its insurers and has filed a statement of defence in relation to both of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of Point Lepreau in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation, which confirmed the April 2006 reassessments. In March 2009, the Company filed an Appeal to the Tax Court of Canada.

Should Maritime Electric be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $14 million in taxes and accrued interest. As at December 31, 2009, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

Exploits Partnership

The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generation 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, a Crown corporation, 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 has 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.

29. Subsequent Event

In January 2010, Fortis completed a $250 million five-year fixed rate reset preference share offering. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into TGI to repay borrowings under the utility's credit facilities in support of working capital and capital expenditure requirements.

30. Comparative Figures

Certain comparative figures have been reclassified to comply with current period classifications, the most significant of which was the reclassification of $48 million from other assets to utility capital assets on the consolidated balance sheet as at December 31, 2008 related to the net book value of amounts paid to AESO for transmission capital projects at FortisAlberta. Capital expenditures related to AESO transmission projects were also reclassified from change in other assets and deferred credits to utility capital asset capital expenditures on the consolidated statement of cash flows for the year ended December 31, 2008. Additionally, $12 million was reclassified from long-term regulatory liabilities to utility capital assets on the consolidated balance sheet as at December 31, 2008 related to the change in presentation adopted by FortisBC as at December 31, 2009 as described in Note 2, Utility Capital Assets.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2009**	2008[1]	2007	2006[2]
Revenue, including equity income	**3,637**	3,903	2,718	1,472
Energy supply costs and operating expenses	**2,572**	2,855	1,904	939
Amortization	**364**	348	273	178
Finance charges	**360**	363	299	168
Corporate taxes	**49**	65	36	32
Results of discontinued operations, gains on sales and other unusual items	**–**	–	8	2
Non-controlling interest	**12**	13	15	8
Preference share dividends	**18**	14	6	2
Net earnings applicable to common share	**262**	245	193	147
Balance Sheets *(in $ millions)*				
Current assets	**1,126**	1,150	1,038	405
Goodwill	**1,560**	1,575	1,544	661
Other long-term assets	**949**	487	424	331
Utility capital assets, income producing properties and intangibles	**8,525**	7,954	7,276	4,049
Total assets	**12,160**	11,166	10,282	5,446
Current liabilities	**1,594**	1,697	1,804	558
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**1,307**	727	697	482
Long-term debt and capital lease obligations (excluding current portion)	**5,276**	4,884	4,623	2,558
Non-controlling interest	**123**	145	115	130
Preference share (classified as debt)	**320**	320	320	320
Shareholders' equity	**3,540**	3,393	2,723	1,398
Cash Flows *(in $ millions)*				
Operating activities	**637**	661	373	263
Investing activities	**1,052**	852	2,033	634
Financing activities	**599**	387	1,826	456
Dividends, excluding dividends on preference shares classified as debt	**161**	191	146	77
Financial Statistics				
Return on average book common shareholders' equity *(%)*	**8.41**	8.70	10.00	11.87
Capitalization Ratios *(%)* (year end)				
Total debt and capital lease obligations (net of cash)	**60.2**	59.5	64.3	61.1
Preference shares (classified as debt and equity)	**6.9**	7.3	5.2	10.0
Common shareholders' equity	**32.9**	33.2	30.5	28.9
Interest Coverage *(x)*				
Debt	**1.9**	1.9	1.9	2.2
All fixed charges	**1.8**	1.8	1.7	2.0
Total gross capital expenditures *(in $ millions)*	**1,024**	935	803	500
Common share data				
Book value per share (year end) *($)*	**18.61**	17.97	16.69	12.19
Average common shares outstanding *(in millions)*	**170.2**	157.4	137.6	103.6
Basic earnings per common share *($)*	**1.54**	1.56	1.40	1.42
Dividends declared per common share *($)*	**0.780**	1.010	0.880	0.700
Dividends paid per common share *($)*	**1.040**	1.000	0.820	0.670
Dividend payout ratio *(%)*	**67.5**	64.1	58.6	47.2
Price earnings ratio *(x)*	**18.6**	15.8	20.7	21.0
Share trading summary				
High price *($)* (TSX)	**29.24**	29.94	30.00	30.00
Low price *($)* (TSX)	**21.52**	20.70	24.50	20.36
Closing price *($)* (TSX)	**28.68**	24.59	28.99	29.77
Volume *(in thousands)*	**121,162**	132,108	100,920	60,094

(1) Certain 2008 comparative figures have been reclassified to comply with current period classifications. Refer to Notes 2 and 30 of the 2009 Annual Consolidated Financial Statements for further details.

(2) As at December 31, 2006, the regulatory provision for future 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 adoped by FortisBC effective December 31, 2009.

Historical Financial Summary

2005[2]	2004	2003	2002	2001	2000	1999
1,441	1,146	843	715	628	580	505
926	766	579	477	418	418	356
158	114	62	65	62	52	45
154	122	86	74	65	56	46
70	47	38	32	29	17	28
10	–	–	–	4	3	–
6	6	4	4	4	3	1
–	–	–	–	–	–	–
137	91	74	63	54	37	29
299	293	191	180	135	166	93
512	514	65	60	33	36	39
471	418	345	241	172	163	122
3,315	2,713	1,563	1,459	1,246	1,056	930
4,597	3,938	2,164	1,940	1,586	1,421	1,184
412	538	296	334	272	225	230
–	–	–	–	–	–	16
477	138	62	39	32	24	27
2,136	1,905	1,031	941	746	678	488
39	37	37	40	36	32	29
320	320	123	–	50	50	50
1,213	1,000	615	586	450	412	344
304	272	157	134	94	97	85
467	1,026	308	349	240	241	122
224	777	232	261	171	178	67
64	51	38	35	30	28	24
12.40	11.28	12.30	12.23	12.44	9.73	8.55
58.7	61.4	60.0	65.2	63.9	60.4	59.6
8.6	9.4	6.7	–	3.6	4.3	5.1
32.7	29.2	33.3	34.8	32.5	35.3	35.3
2.5	2.3	2.2	2.3	2.3	2.1	2.3
2.1	2.0	2.1	2.2	2.2	1.9	2.1
446	279	208	229	149	158	86
11.74	10.45	8.82	8.50	7.50	6.97	6.55
101.8	84.7	69.3	65.1	59.5	54.1	52.2
1.35	1.07	1.06	0.97	0.90	0.68	0.56
0.605	0.548	0.525	0.498	0.470	0.460	0.455
0.588	0.540	0.520	0.485	0.468	0.460	0.453
43.7	50.3	48.9	49.9	51.9	67.6	80.8
18.0	16.2	13.9	13.5	13.0	13.2	14.0
25.64	17.75	15.24	13.28	11.89	9.19	9.93
17.00	14.23	11.63	10.76	8.56	6.88	7.29
24.27	17.38	14.73	13.13	11.74	9.00	7.85
37,706	29,254	31,180	21,676	21,460	26,760	9,024

Board of Directors

Board of Directors (back row l-r): Peter E. Case, Frank J. Crothers, Roy P. Rideout, Ida J. Goodreau; (middle row l-r): Harry McWatters, Michael A. Pavey, David G. Norris, John S. McCallum; (front row l-r): H. Stanley Marshall, Geoffrey F. Hyland, Douglas J. Haughey, Ronald D. Munkley

Geoffrey F. Hyland ∗★✷ *Chair, Fortis Inc., Caledon, ON*
Mr. Hyland, 65, joined the Fortis Inc. Board in May 2001 and was appointed Chair of the Board in May 2008. He retired as President and CEO of Shawcor Ltd. in June 2005 after 37 years of service. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of SCITI Total Return Trust and Exco Technologies Limited.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 55, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. He was then a consultant to the utility industry and its regulators for three years. Prior to his position at CIBC, he was Managing Director at BMO Nesbitt Burns. Mr. Case was appointed Chair of the Board of FortisOntario Inc. in 2009. He has been a Director of FortisOntario Inc. since 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, BS*
Mr. Crothers, 65, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the past President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited and serves on the Board of Belize Electricity Limited. Mr. Crothers also serves as a Director of Templeton Mutual Funds, Talon Metals Corp. and Fidelity Merchant Bank & Trust (Cayman) Limited.

Ida J. Goodreau ✷ *Corporate Director, Vancouver, BC*
Ms. Goodreau, 58, joined the Fortis Inc. Board in May 2009. She is the past President and CEO of Lifelabs. Prior to joining Lifelabs in March 2009, Ms. Goodreau was President and CEO of the Vancouver Coastal Health Authority since 2002. She held senior leadership roles in several Canadian and international pulp and paper and natural gas companies prior to entering the health care field. She is a Director of Terasen Inc.

Douglas J. Haughey ∗ *President and CEO, Windshift Capital Corp., Calgary, AB*
Mr. Haughey, 53, joined the Fortis Inc. Board in May 2009. Prior to forming Windshift Capital Corp. in 2008, he was President and CEO of Spectra Energy Income Fund and President of Spectra Energy Transmission West, Spectra's Canadian natural gas and liquids midstream business. Mr. Haughey also led Spectra's strategic development and mergers and acquisitions teams, based in Houston, Texas. He serves as a Director of Pembina Pipeline Income Fund.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 59, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ∗★ *Professor of Finance, University of Manitoba, Winnipeg, MB*
Mr. McCallum, 66, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters ★ *Wine Consultant, Summerland, BC*
Mr. McWatters, 64, joined the Fortis Inc. Board in May 2007. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Harry McWatters Inc., Vintage Consulting Group Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

Ronald D. Munkley ★ *Corporate Director, Mississauga, ON*
Mr. Munkley, 63, joined the Fortis Inc. Board in May 2009. He retired in April 2009 as Vice Chairman and Head of the Power and Utility Business of CIBC World Markets. Mr. Munkley had acted as an advisor on most Canadian utility transactions since joining CIBC World Markets in 1998. Prior to that, he was employed at Enbridge Consumers Gas for 27 years, culminating as Chairman, President and CEO. He led Enbridge Consumers Gas through deregulation and restructuring in the 1990s.

David G. Norris ∗✷ *Corporate Director, St. John's, NL*
Mr. Norris, 62, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ✷ *Corporate Director, Moncton, NB*
Mr. Pavey, 62, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ★✷ *Corporate Director, Halifax, NS*
Mr. Rideout, 62, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of NAV CANADA.

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

Investor Information

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

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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.

Expected Dividend* and Earnings Dates

Dividend Record Dates	
May 7, 2010	August 6, 2010
November 5, 2010	February 4, 2011
Dividend Payment Dates	
June 1, 2010	September 1, 2010
December 1, 2010	March 1, 2011
Earnings Release Dates	
April 30, 2010	August 4, 2010
November 5, 2010	February 3, 2011

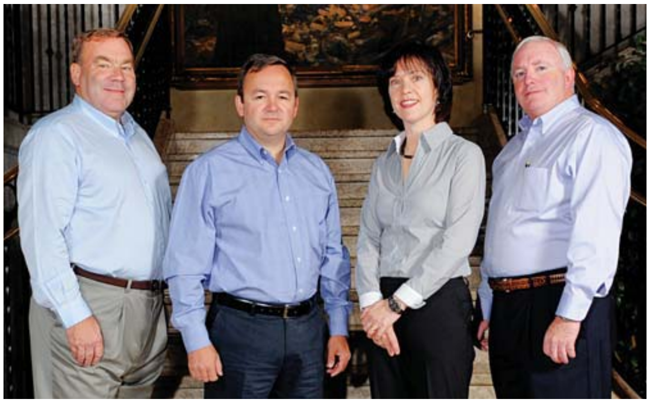
* *The declaration and payment of dividends are subject to the Board of Directors' approval.*

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 per cent 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.*



Fortis Inc. Officers (l-r): Stan Marshall, President and CEO; Barry Perry, VP, Finance and CFO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Ronald McCabe, VP, General Counsel and Corporate Secretary

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

Manager, Investor
and Public Relations
T: 709.737.2800
F: 709.737.5307
E: investorrelations@fortisinc.com

Annual Meeting

Tuesday, May 4, 2010
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Design and Production:
Colour, St. John's, NL
www.colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group,
Ottawa, ON

Cover photos by: Cam Craig, Terasen Gas employee
Jodie Foster-Sexsmith, FortisBC employee
Jack LeClair, Charlottetown, PE
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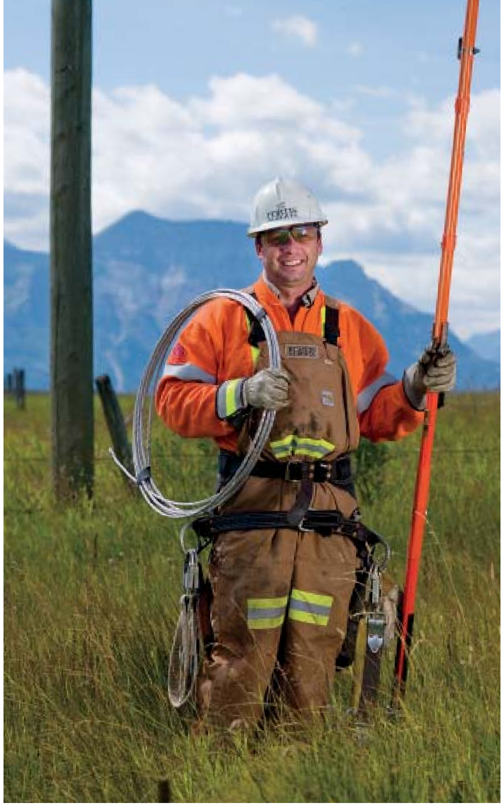
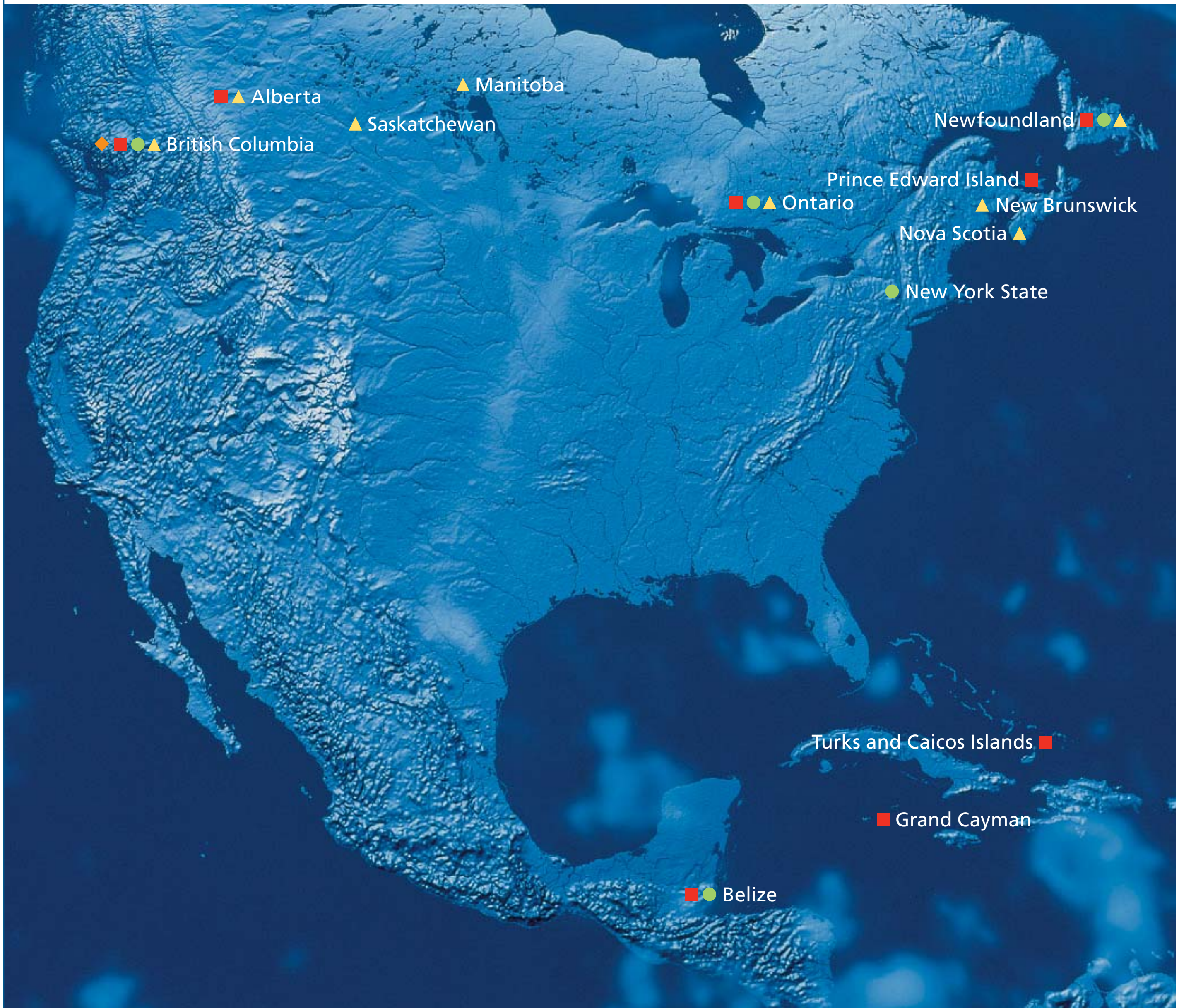


FORTIS INC.

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

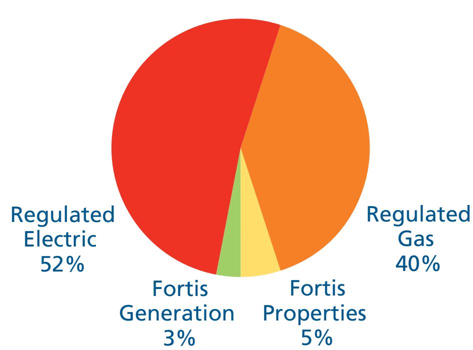
Fortis Properties ▲

Real Estate and Hotels

Across Canada

Total Assets Approach $13 Billion

(as at December 31, 2010)



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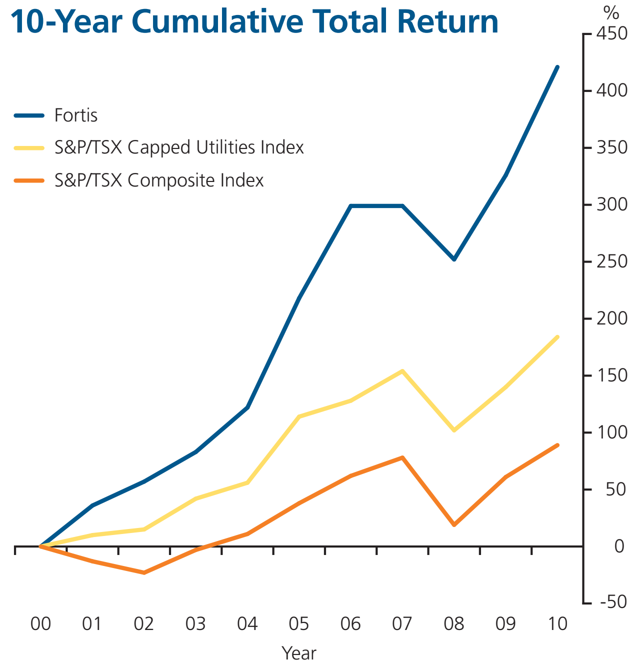
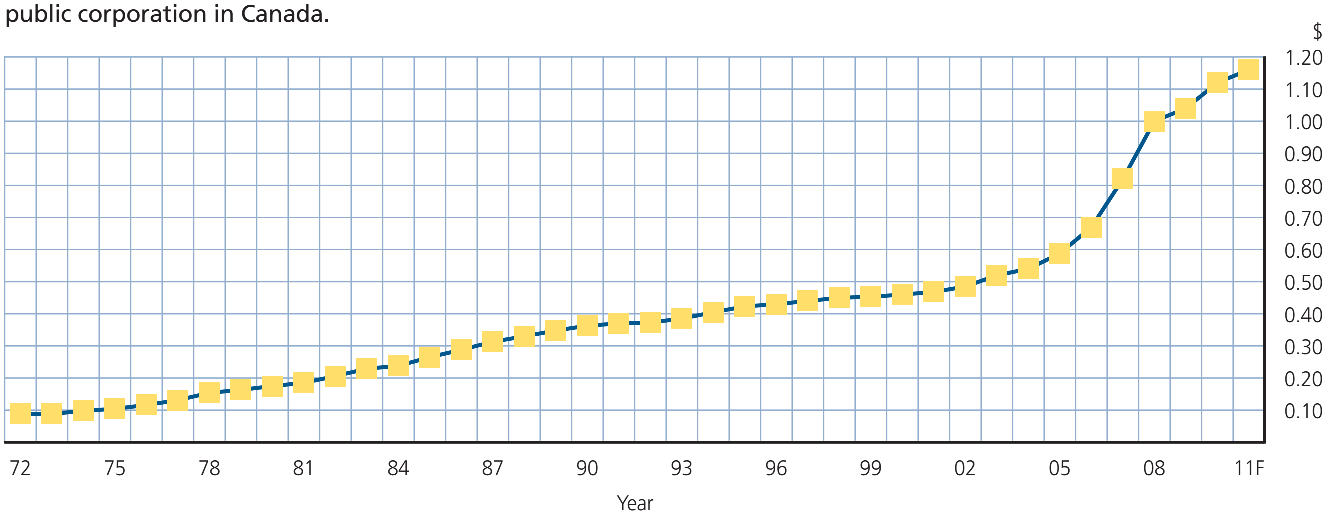
10-Year Cumulative Total Return



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.

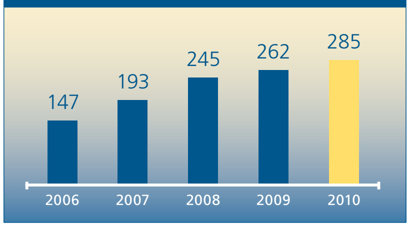
ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

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.

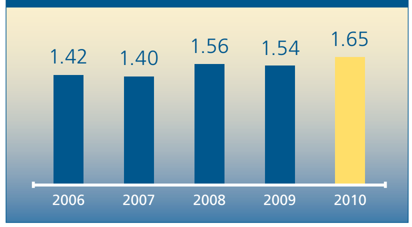
Investor Highlights

Five-Year Performance

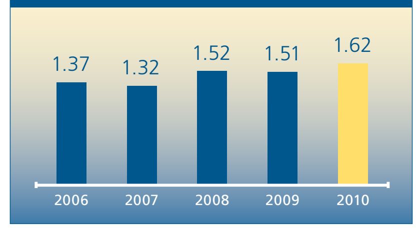
Earnings Applicable to Common Equity Shareholders ($M)



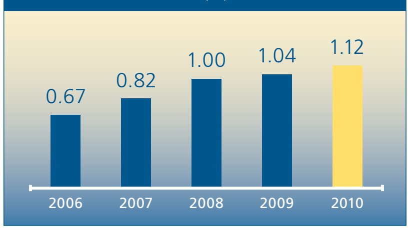
Basic Earnings per Common Share ($)



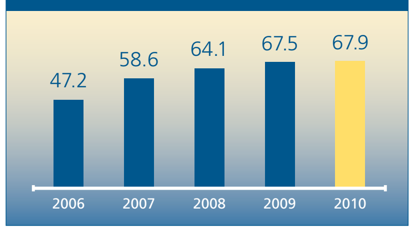
Diluted Earnings per Common Share ($)



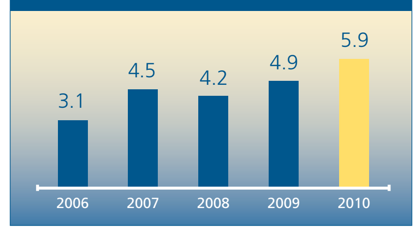
Dividends Paid per Common Share ($)



Dividend Payout Ratio (%)

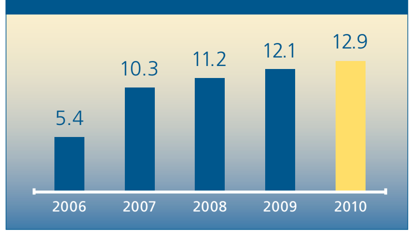


Market Capitalization ($B)

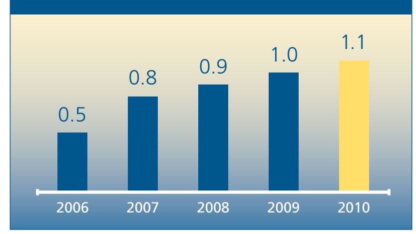


Return on Average Book Common Shareholders' Equity (%)

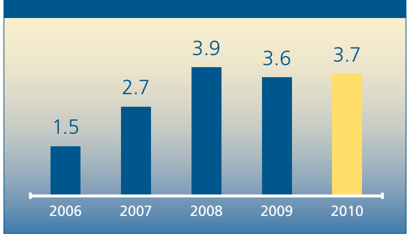
Assets ($B)



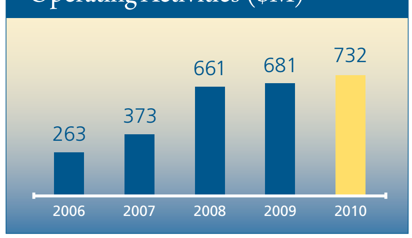
Capital Expenditures ($B)



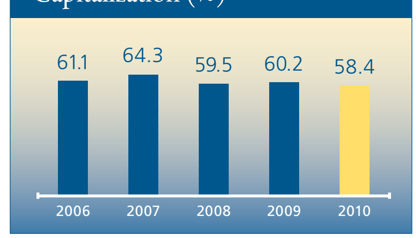
Revenue ($B)



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

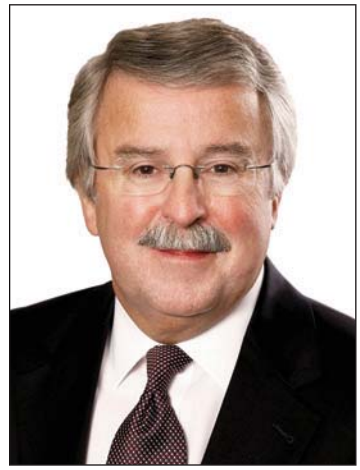
(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2010

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

Report to Shareholders

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.

Stan Marshall, President and CEO, Fortis Inc.



David Norris, Chair of the Board, Fortis Inc.

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.

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.

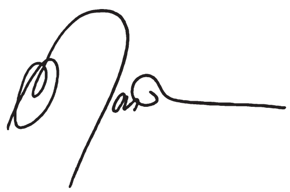
There is much work to be done. We expect to spend about $1.2 billion on our capital program in 2011 and near $5.5 billion over the next five years, driven by investment in infrastructure at our regulated utilities in western Canada and the Waneta Expansion Project. This investment will continue to drive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

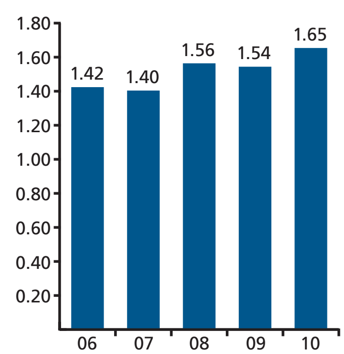
For the Years Ended December 31	**2010**	2009	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**285**	262	23
Basic Earnings per Common Share *($)*	**1.65**	1.54	0.11
Diluted Earnings per Common Share *($)*	**1.62**	1.51	0.11
Weighted Average Number of Common Shares Outstanding *(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.

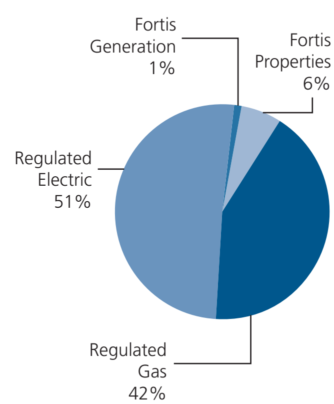
Basic earnings per share were $1.65 in 2010 compared to $1.54 in 2009, mainly due to growth in earnings year over year.

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 *($)*

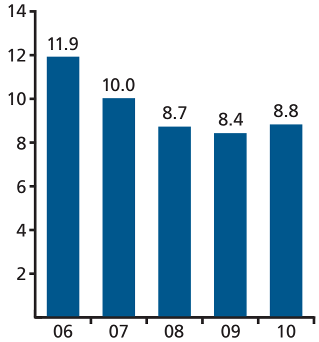


Revenue [(1)]
(year ended December 31, 2010)

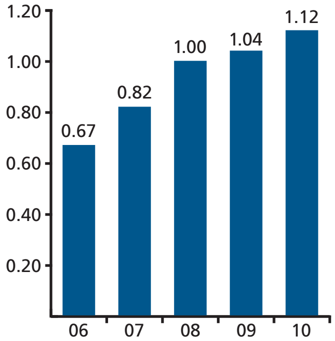


(1) Excludes Corporate and Other

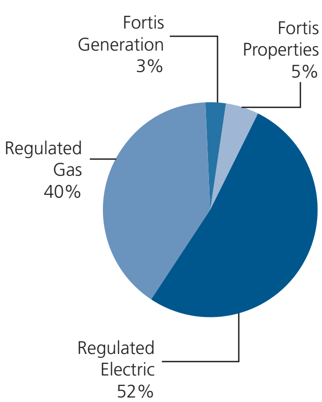
Return on Average Book Common Shareholders' Equity *(%)*



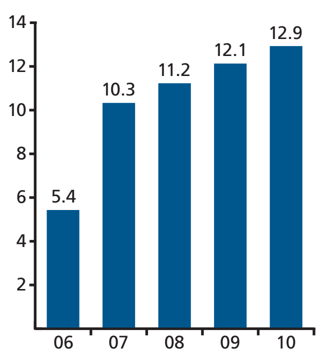
Dividends Paid per Common Share *($)*



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

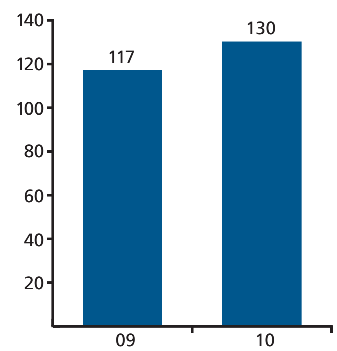
[(2)] Results for 2009 reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009, when the Rankine water rights expired at the end of a 100-year term. Results reflect contribution from the Vaca hydroelectric generating facility in Belize from March 2010 when 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)

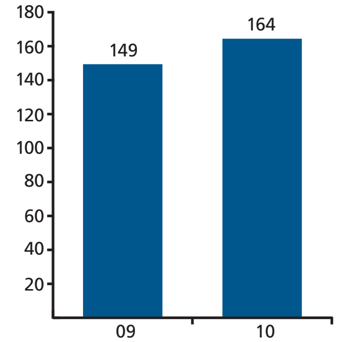
Unfavourable

- 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 Earnings *($ millions)*



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%).

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.

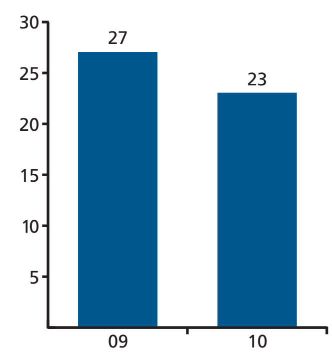
In February 2011 FortisOntario and First Nations' Lake Huron Anishinabek Transmission Company Inc. ("LHATC") entered into a memorandum of understanding ("MOU") for a joint venture to develop, construct and operate regulated electricity transmission projects in Ontario. FortisOntario will hold a minimum 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.

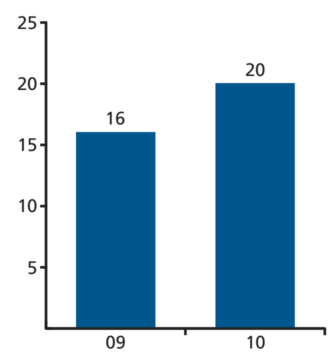
[3] Results reflect contribution from the Rankine hydroelectric generating facility in Ontario until April 30, 2009, when the Rankine water rights expired at the end of a 100-year term.

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

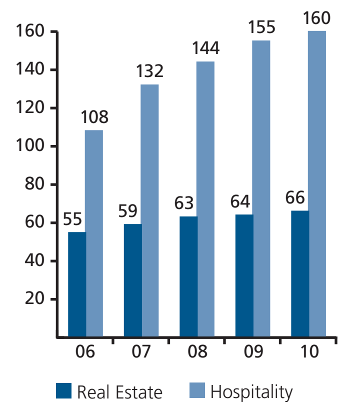
Favourable

- 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, 2010
(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.

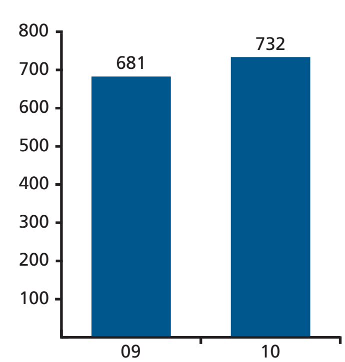
Summary of Consolidated Cash Flows

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.

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.

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).

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

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.

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.

December 31, 2010 and 2009

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

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.

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.

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.

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	

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.

(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.

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.

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

(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.

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		

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

December 31, 2010 and 2009

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

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)

(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

December 31, 2010 and 2009

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.

December 31, 2010 and 2009

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.

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

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Investor Information

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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

Board of Directors

David G. Norris ∗ ✷ ★
Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Peter E. Case ∗
Corporate Director
Kingston, Ontario

Frank J. Crothers
Chairman and CEO, Island Corporate Holdings
Nassau, Bahamas

Ida J. Goodreau ✷
Corporate Director
Vancouver, British Columbia

Douglas J. Haughey ∗
President and CEO, Provident Energy Ltd.
Calgary, Alberta

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

John S. McCallum ∗ ★
Professor of Finance, University of Manitoba
Winnipeg, Manitoba

Harry McWatters ★
Wine Consultant
Summerland, British Columbia

Ronald D. Munkley ★
Corporate Director
Mississauga, Ontario

Michael A. Pavey ✷
Corporate Director
Moncton, New Brunswick

Roy P. Rideout ✷ ★
Corporate Director
Halifax, Nova Scotia

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

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

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Shawn Talbot Photography, Kelowna, BC
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Oscar Kaus, Newfoundland Power employee

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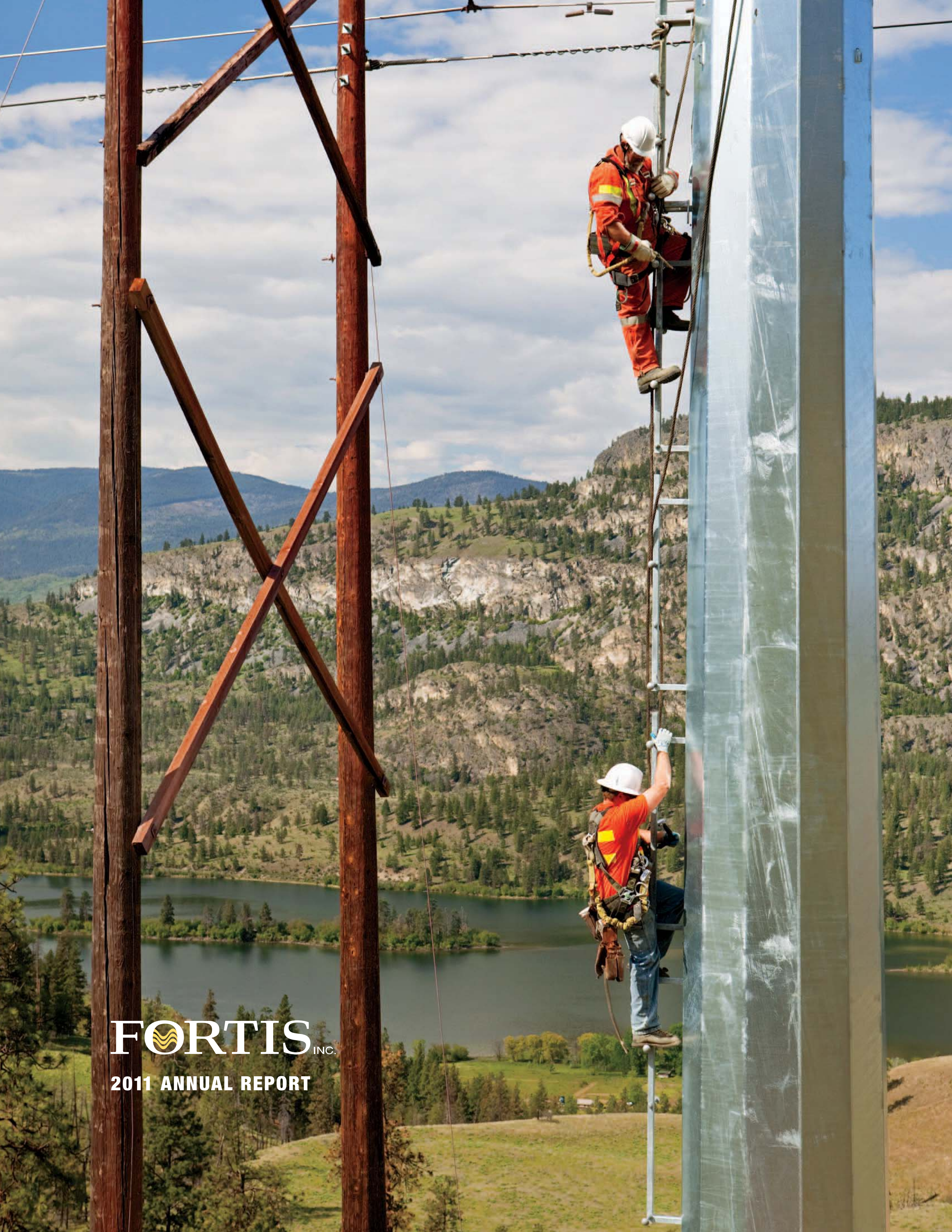
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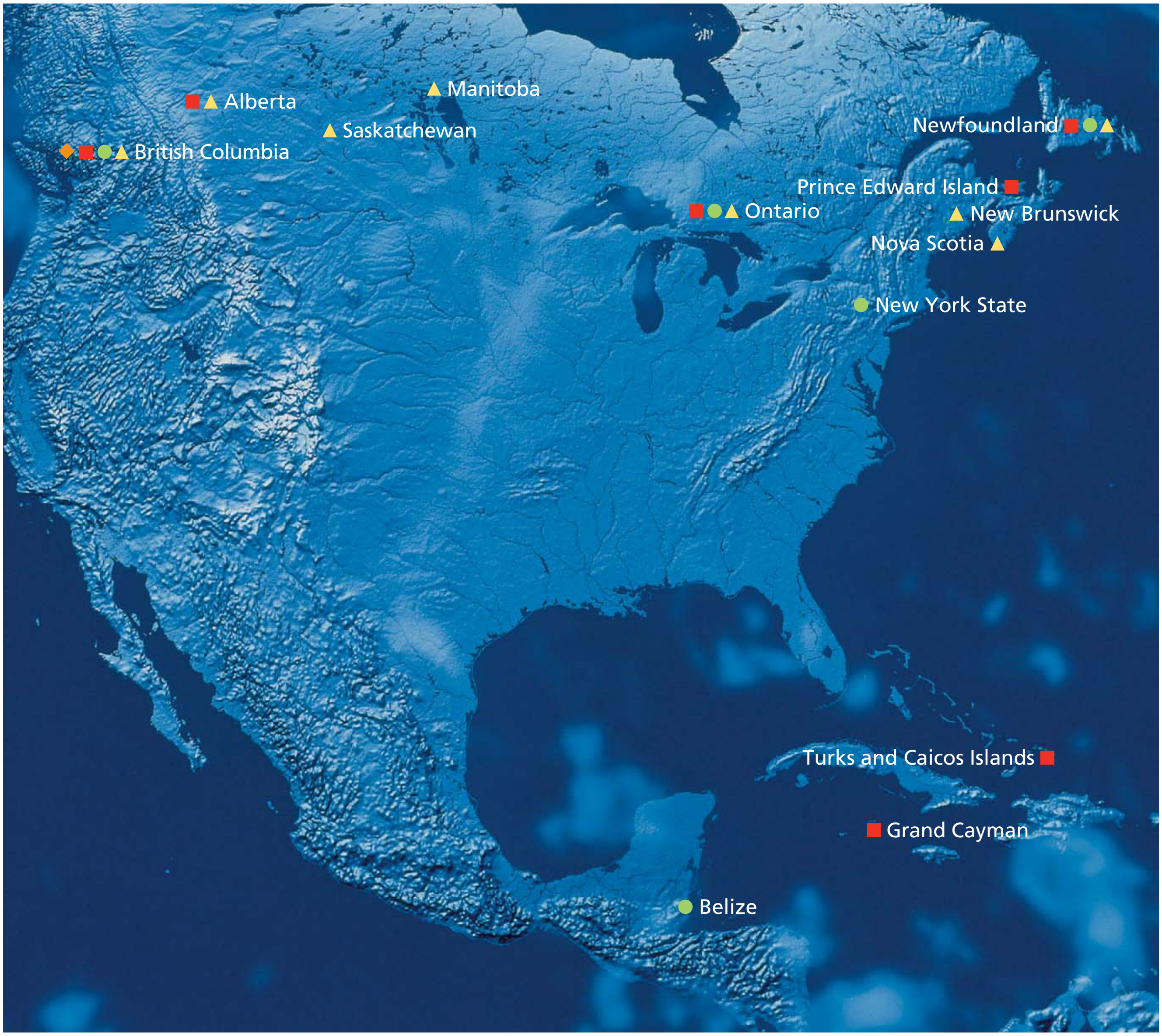
2011 ANNUAL REPORT

Operations



Regulated Utility Operations

Gas Operations

FortisBC *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation

Production Areas

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

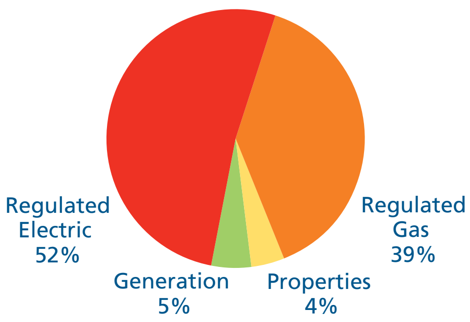
Fortis Properties

Real Estate and Hotels

Across Canada

Total Assets $13.6 Billion

(as at December 31, 2011)



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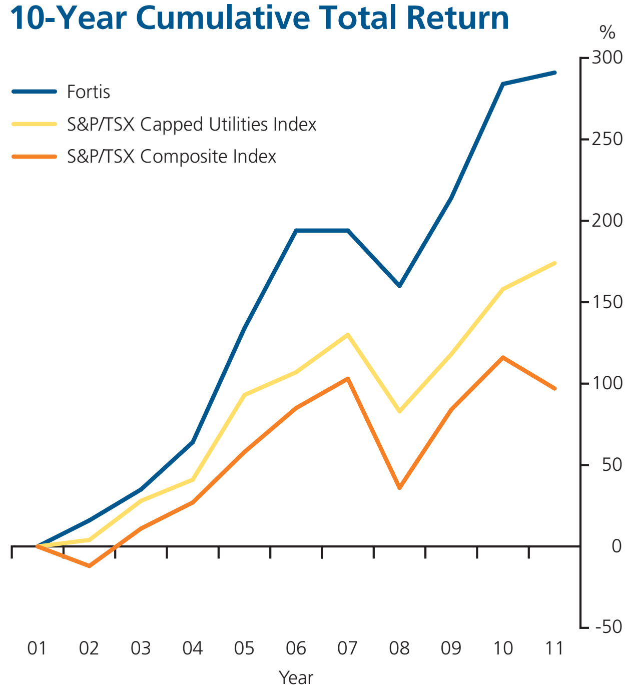
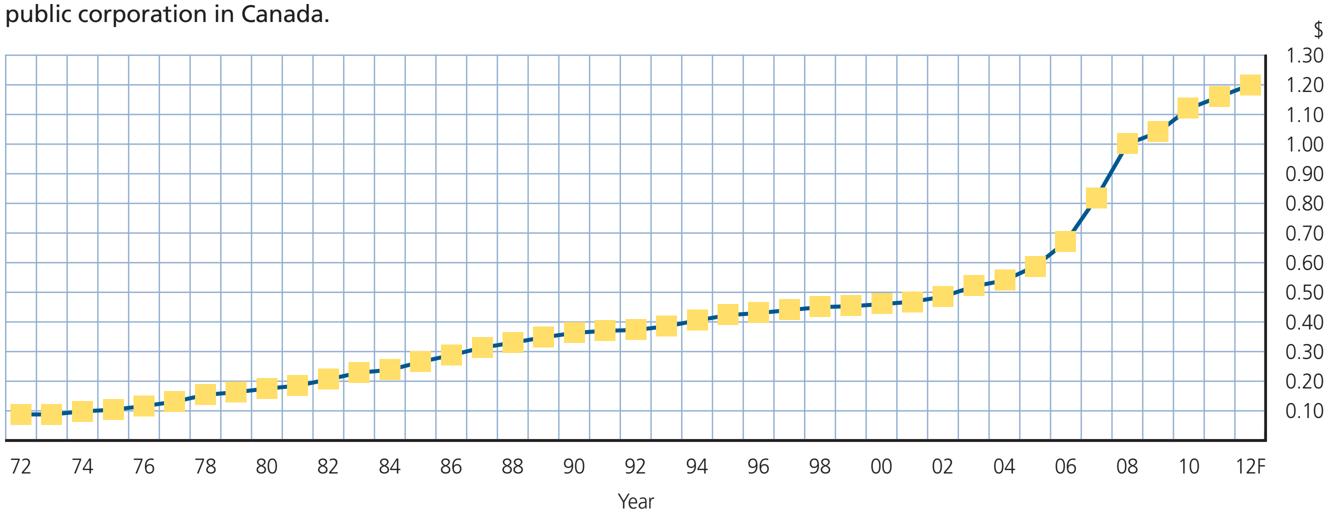
10-Year Cumulative Total Return



Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 39 consecutive years, the longest record of any public corporation in Canada.



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

The Corporation will continue to focus on three primary objectives:

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

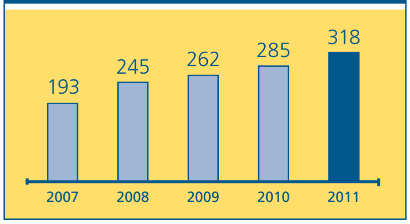
ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

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

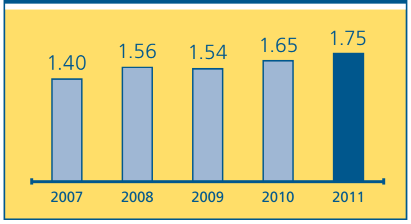
Investor Highlights

Five-Year Performance

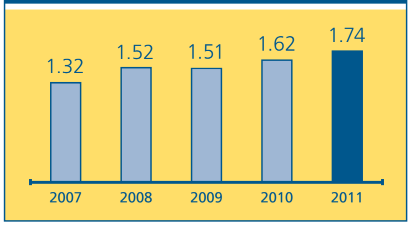
Earnings Attributable to Common Equity Shareholders ($M)



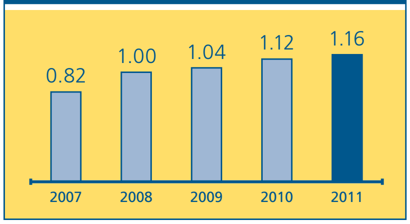
Basic Earnings per Common Share ($)



Diluted Earnings per Common Share ($)

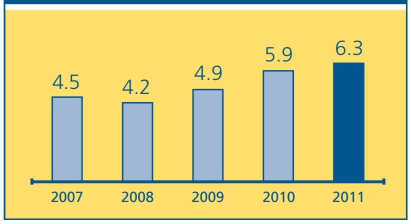


Dividends Paid per Common Share ($)

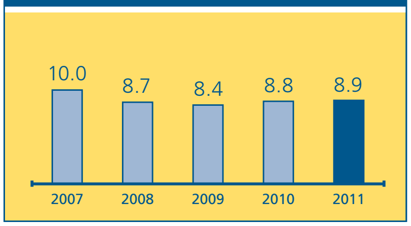


Dividend Payout Ratio (%)

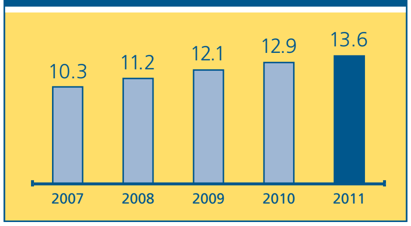
Market Capitalization ($B)



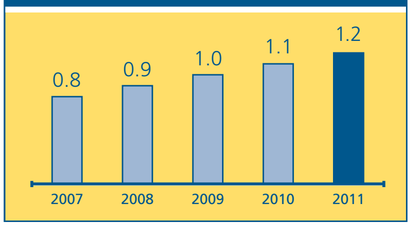
Return on Average Book Common Shareholders' Equity (%)



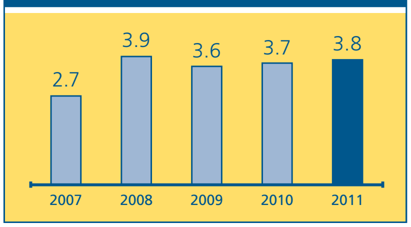
Assets ($B)



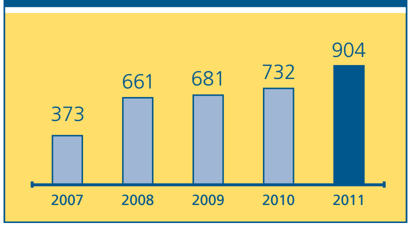
Capital Expenditures ($B)



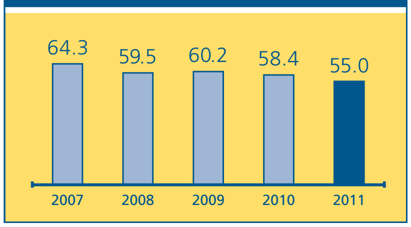
Revenue ($B)



Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



All financial information is presented in Canadian dollars.

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

Regulated

Gas

FortisBC [1]	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) [2]	Earnings ($M)	Allowed ROE (%) [3] 2011	2012
Total	**956,000**	**1,789**	**1,210**	**203**	**253**	**5.3**	**3.6**	**139**	**9.50**	**9.50** [4]

Electric

	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) [2]	Earnings ($M)	Allowed ROE(%) [3] 2011	2012
FortisAlberta	499,000	1,036	2,505	16,367	416	2.7	2.0	75	8.75	8.75
FortisBC	162,000	528	669	3,143	102	1.6	1.1	48	9.90	9.90 [4]
Newfoundland Power	247,000	640	1,166	5,553	81	1.2	0.9	34	8.38	8.38 [5]
Maritime Electric	75,000	181	224	1,048	27	0.4	0.3	12	9.75	9.75
FortisOntario	64,000	198	276	1,318	20	0.3	0.2	10	8.01/9.85 [6]	8.01/9.85 [6]
Belize Electricity [7]	–	–	76	194	9	0.1	–	–	–	–
Caribbean Utilities [8]	27,000	193	99	554	36	0.5	0.4	11	7.75–9.75 [9]	7.75–9.75 [9] [10]
Fortis Turks and Caicos	9,500	114	30	170	26	0.2	0.2	9	17.50 [9] [11]	17.50 [9] [11]
Total	**1,083,500**	**2,890**	**5,045**	**28,347**	**717**	**7.0**	**5.1**	**199**		

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

(2) Forecast midyear 2012

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

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

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

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

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

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

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

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

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

Non-Regulated

Fortis Generation [1]

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

Fortis Properties [2]

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

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

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

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

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

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

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

Report to Shareholders

Stan Marshall,
President and CEO, Fortis Inc.

David Norris,
Chair of the Board, Fortis Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in New York State's Mid-Hudson River Valley, whose operations are similar to our regulated utility operations in Canada. The acquisition, which is subject to CH Energy Group's common shareholders' approval, and regulatory and other approvals, is anticipated to close in approximately 12 months and is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

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

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

On behalf of the Board of Directors,

David G. Norris
Chair of the Board
Fortis Inc.

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

Management Discussion and Analysis

Dated March 13, 2012

FORWARD-LOOKING INFORMATION

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


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

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's focus on the United States and Canada in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America; investment to harvest shale oil and gas in Alberta, Canada, is expected to continue and should favourably impact energy sales and rate base investment in FortisAlberta's service territory; the expectation that the Government of British Columbia's new Natural Gas Strategy should favourably impact natural gas throughput at the FortisBC Energy companies; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030; the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the next five years; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program should support continuing growth in earnings and dividends; there is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; forecast midyear rate base for each of the Corporation's four large Canadian regulated utilities; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2012 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2012 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; except for debt at the Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2012; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2012; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2012; the expectation that electricity sales growth at the Corporation's regulated utilities in the Caribbean will be minimal for 2012; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; the expectation that FortisBC will continue efforts in 2012 to further integrate its gas and electricity businesses; the expectation that the Corporation's consolidated earnings and earnings per common share for 2012 will not be materially impacted by the transition to accounting principles generally accepted in the United States ("US GAAP"); the expectation of an increase in consolidated defined benefit net pension cost for 2012 and the fact that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future; and the expected timing of the closing of the acquisition of CH Energy Group, Inc. by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding one-time transaction expenses. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of *natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards ("IFRS") after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology ("IT") infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on allowed rates of return on common shareholders' equity of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risk associated with defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of IT infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2011.*

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

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CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. In 2011 the Corporation's electricity distribution systems met a combined peak demand of 5,045 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ").

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

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and hotels and commercial office and retail space, which are treated as two separate segments. The Corporation's non-regulated generation assets have a combined generating capacity of 139 MW, which is mainly hydroelectric, and are managed as a segment to ensure standard operating practices, to leverage expertise across the various jurisdictions and to allow the pursuit of additional non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return. Income from non-regulated investments is used to help offset corporate holding company expenses, a large part of which is interest expense associated with the financing of premiums paid on the acquisition of regulated utilities.

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

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

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

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

Regulated Gas Utilities – Canadian

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

FEI is the largest distributor of natural gas in British Columbia, serving approximately 852,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves more than 102,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service to more than 2,600 customers.

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

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 499,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 162,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC Electric component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 247,000 customers. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving more than 75,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to more than 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company has an installed diesel-powered generating capacity of 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

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

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

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

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Includes six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

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

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

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

Non-Regulated – Fortis Properties: Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

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

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

CORPORATE VISION AND STRATEGY

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

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. Over the past 10 years, earnings per common share of Fortis have grown at a compound annual growth rate of 6.9%. Fortis delivered an average annualized total return to shareholders of approximately 15% over the past 10 years, exceeding the Standard and Poor's ("S&P")/Toronto Stock Exchange ("TSX") Capped Utilities and S&P/TSX Composite Indices, which delivered annualized performance of approximately 11% and 7%, respectively, over the same period.

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

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

KEY TRENDS AND RISKS

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

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

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

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

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

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

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

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

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

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

Greenhouse Gas Emissions: Implemented and potential government legislation, driven by concerns over the impact of greenhouse gas ("GHG") emissions in contributing to climate change, has significant implications for the energy industry. Canada accounts for about 2% of the world's GHG emissions, as per Scotia Capital's April 2011 *Energy Infrastructure Outlook*. Canada has one of the cleanest electricity systems in the world, with three quarters of its energy supply having no GHG emissions. In 2009 the electricity sector in Canada was responsible for 14% of the country's GHG emissions, according to Environment Canada's *National Inventory Report 1990–2009*. The most significant impact for Fortis with respect to GHG emissions legislation pertains to FortisBC's gas business as it relates to the combustion of and/or release of natural gas.

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

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

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

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

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

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

Regulator-Approved Allowed ROEs

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

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

The use of automatic adjustment mechanisms to annually calculate allowed ROEs was introduced in Canada in the mid to late 1990s, with the goal of providing efficiency in the regulatory process by reducing the frequency of cost of capital reviews. Generally, the mechanisms used a formula that calculated an annual adjustment to allowed ROEs based upon changes in long-term Canada bond rates. As long-term Canada bond rates declined, the use of ROE automatic adjustment mechanisms came under increased scrutiny in many jurisdictions in Canada because they failed to produce allowed ROEs that were high enough to meet the fair return standard. The regulatory decisions received by the Corporation in 2009 regarding cost of capital reviews in British Columbia and Alberta resulted in the elimination of the ROE automatic adjustment mechanism for FortisBC's gas and electric utilities and the suspension of the mechanism at FortisAlberta. The suspension of the automatic adjustment mechanism has been continued in Alberta for 2011 and 2012, with an allowed ROE ordered by the Alberta Utilities Commission ("AUC") of 8.75% for these years. The BCUC issued preliminary notification in November 2011 to all regulated utilities in British Columbia that it plans to initiate a Generic Cost of Capital ("GCOC") Proceeding. The proceeding will commence in March 2012 and will review, among other things, cost of capital and whether the re-establishment of an ROE automatic adjustment mechanism is warranted. An ROE automatic adjustment mechanism was in effect at Newfoundland Power for 2011. In December 2011 the regulator approved Newfoundland Power's request to suspend the operation of the ROE automatic mechanism for 2012 and to review cost of capital in 2012.

Uncertainty exists regarding the duration of the current environment of low interest rates and what effect it may have on allowed ROEs of the Corporation's regulated utilities.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is regulated by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been satisfactory, with reasonably fair decisions reached in the past several years, with the exception of the June 2008 regulatory rate decision received by Belize Electricity. That decision ultimately led to the expropriation of the Corporation's investment in Belize Electricity by the GOB in June 2011. For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A.

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

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

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

Fortis continues to control and consolidate the financial statements of BECOL. For further information, refer to the "Business Risk Management – Investment in Belize" section of this MD&A.

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

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities issue debt usually at terms ranging between 10 and 50 years. As at December 31, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $2.2 billion in credit facilities, of which approximately $1.9 billion was unused as at December 31, 2011. With strong credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2012.

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

Dividend Increases: Dividends per common share increased to $1.16 in 2011. Fortis increased its quarterly common share dividend to 30 cents, commencing with the first quarter dividend paid in 2012. The 3.4% increase in the quarterly common share dividend translates into an annualized dividend of $1.20 for 2012 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada. Fortis expects that its significant capital program should support continuing growth in earnings and dividends.

Caribbean Operating Environment: Regulated assets in the Caribbean region comprised 7% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 8%). Generally, the achieved ROA at electric utilities in the Caribbean region is higher than that achieved by electric utilities in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors, as well as weather conditions, including a significant exposure to hurricanes. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

While still higher than that achieved by regulated utilities in Canada, the allowed ROA at Caribbean Utilities was lowered beginning in 2008 due to the negotiation of new licences at the utility, and the achieved ROA at Fortis Turks and Caicos has been significantly lower than that allowed under its licence due to significant capital investment occurring at the utility in recent years without corresponding increases in base customer electricity rates.

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

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

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

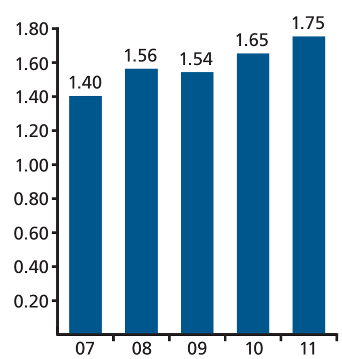
For further information with respect to the Corporation's transition to US GAAP, refer to the "Business Risk Management – Transition to New Accounting Standards" and "Future Accounting Changes" sections of this MD&A.

SUMMARY FINANCIAL HIGHLIGHTS

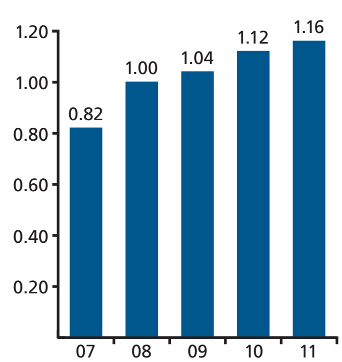
For the Years Ended December 31	2011	2010	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**318**	285	33
Basic Earnings per Common Share *($)*	**1.75**	1.65	0.10
Diluted Earnings per Common Share *($)*	**1.74**	1.62	0.12
Weighted Average Number of Common Shares Outstanding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

Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $318 million in 2011, up $33 million from $285 million in 2010. The increase in earnings was due to the $11 million after-tax fee paid to Fortis following the termination of the Merger Agreement with CVPS combined with higher earnings from the Corporation's Canadian regulated utilities associated with: (i) rate base growth, driven by the regulated utilities in western Canada; (ii) lower-than-expected corporate income taxes, finance charges and amortization costs, and increased gas transportation volumes to the forestry and mining sectors at the FortisBC Energy companies, partially offset by lower-than-expected customer additions at these companies; (iii) higher capitalized allowance for funds used during construction ("AFUDC") at FortisAlberta, as well as customer growth and increased energy deliveries, return earned on additional investment in automated meters, as approved by the regulator, and an approximate $1 million gain on the sale of property, partially offset by the impact of a lower allowed ROE for 2011 at the utility; (iv) lower purchased power costs and higher electricity sales at FortisBC Electric, partially offset by lower capitalized AFUDC at the utility; (v) an increase in the allowed ROE at Algoma Power; and (vi) lower corporate business development costs and finance charges. The above increases were partially offset by: (i) lower earnings from Caribbean Regulated Electric Utilities, due to the expropriation of Belize Electricity in June 2011, combined with lower earnings at Fortis Turks and Caicos due to higher operating expenses and amortization costs, partially offset by reduced energy supply costs in 2011; (ii) decreased earnings at Fortis Properties reflecting higher corporate income taxes and lower occupancies at hotels in western Canada; (iii) decreased earnings from non-regulated hydroelectric generation operations, largely due to lower production in Belize because of reduced rainfall, and overall lower interest income; (iv) lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with new joint-use pole support structure arrangements with Bell Aliant Inc. ("Bell Aliant") in 2011 and higher operating expenses, partially offset by reduced energy supply costs in 2011 and higher electricity sales; and (v) approximately $1 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated earnings due to the weakening of the US dollar relative to the Canadian dollar year over year.

Basic Earnings per Common Share *($)*



Dividends Paid per Common Share *($)*

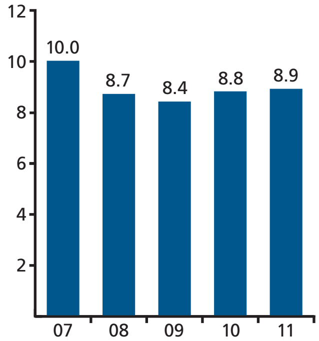


Basic Earnings per Common Share: Basic earnings per common share were $1.75 in 2011 compared to $1.65 in 2010. The increase was due to improved performance, partially offset by the impact of an increase in the weighted average number of common shares outstanding associated with the public common equity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

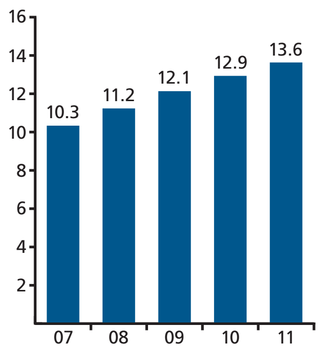
Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $904 million for 2011, up $172 million from $732 million for 2010. The increase was driven by favourable changes in working capital, mainly related to accounts payable, accounts receivable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

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

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



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



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

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

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

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

CONSOLIDATED RESULTS OF OPERATIONS

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

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- Approximately $15 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant in 2011
- Increased performance-based rate-setting ("PBR")-incentive adjustments to be refunded to customers by FortisBC Electric

Factors Contributing to Energy Supply Costs Variance

Unfavourable

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

Favourable

- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower purchased power costs at FortisBC Electric
- Approximately $8 million associated with favourable foreign currency translation

Factors Contributing to Operating Expenses Variance

Unfavourable

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

Favourable

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

Factors Contributing to Amortization Costs Variance

Unfavourable

- Continued investment in energy infrastructure and income producing properties

Favourable

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

Factors Contributing to Other Income (Expenses) Variance

Favourable

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

Factors Contributing to Finance Charges Variance

Unfavourable

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

Favourable

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

Factors Contributing to Corporate Taxes Variance

Unfavourable

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

Favourable

- Lower statutory income tax rates

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31

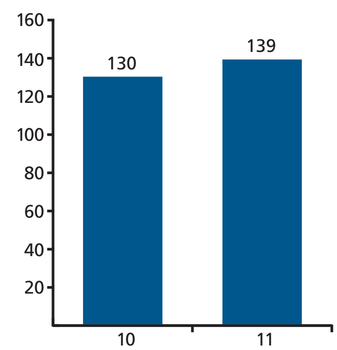
($ millions)	**2011**	2010	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**139**	130	9
Regulated Electric Utilities – Canadian			
FortisAlberta	***75***	*68*	*7*
FortisBC Electric	***48***	*42*	*6*
Newfoundland Power	***34***	*35*	*(1)*
Other Canadian Electric Utilities	***22***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

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A. A discussion of the Corporation's consolidated capital expenditure program and breakdown of actual 2011 and forecast 2012 gross capital expenditures by segment is provided in the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

REGULATED UTILITIES

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

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



Regulated Gas Utilities – Canadian

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

FortisBC Energy Companies

Gas Volumes by Major Customer Category

Years Ended December 31

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

Factors Contributing to Gas Volumes Variance

Favourable

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

Unfavourable

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

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

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

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

FortisBC Energy Companies

Financial Highlights

Years Ended December 31

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Factors Contributing to Earnings Variance

Favourable

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

Unfavourable

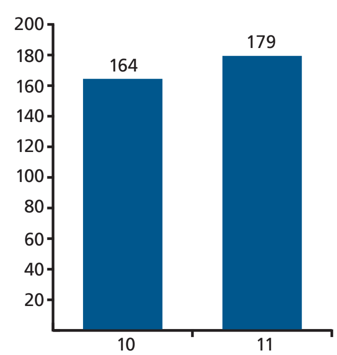
- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Lower-than-expected customer additions in 2011

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

Regulated Electric Utilities – Canadian

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

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



FortisAlberta

Financial Highlights

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

Factors Contributing to Energy Deliveries Variance

Favourable

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

Unfavourable

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

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Factors Contributing to Earnings Variance

Favourable

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

Unfavourable

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

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

FortisBC Electric

Financial Highlights

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

Factors Contributing to Electricity Sales Variance

Favourable

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Factors Contributing to Earnings Variance

Favourable

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

Unfavourable

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

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

Newfoundland Power

Financial Highlights

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

Factors Contributing to Electricity Sales Variance

Favourable

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Factors Contributing to Earnings Variance

Unfavourable

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

Favourable

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

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

Other Canadian Electric Utilities

Financial Highlights

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

Factors Contributing to Electricity Sales Variance

Favourable

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

Unfavourable

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Factors Contributing to Earnings Variance

Favourable

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

Unfavourable

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

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

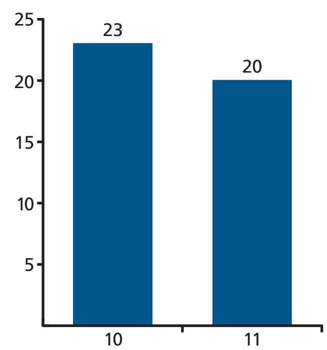
Both Algoma Power's allowed ROE for 2012 of 9.85% and Canadian Niagara Power's allowed ROE for 2012 of 8.01% remain unchanged from 2011.

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

Regulated Electric Utilities – Caribbean

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

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



Financial Highlights

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

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

Factors Contributing to Electricity Sales Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. For further information, refer to the "Business Risk Management – Investment in Belize" section of this MD&A.
- Reduced energy consumption, due to challenging economic conditions in the region, the high cost of fuel and the early and extended closure of certain hotel and other commercial customers in the Turks and Caicos Islands resulting from a hurricane in August 2011
- The number of work permit holders in the region has declined significantly, causing some rental properties with active electricity connections to be vacant.
- Excluding Belize Electricity, there was no growth in electricity sales year over year.

Favourable

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

Factors Contributing to Revenue Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $13 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year

Favourable

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

Factors Contributing to Earnings Variance

Unfavourable

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

Favourable

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

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

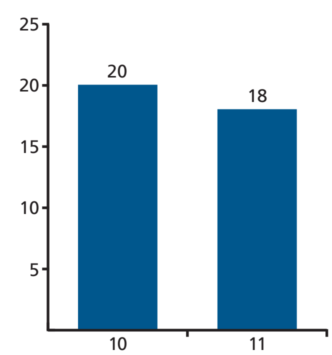
NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

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

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



Factors Contributing to Energy Sales Variance

Unfavourable

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

Factors Contributing to Revenue Variance

Unfavourable

- Decreased production in Belize

Favourable

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

Factors Contributing to Earnings Variance

Unfavourable

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

Favourable

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

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

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

Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31 *($ millions)*	2011	2010	Variance
Hospitality Revenue	**164**	160	4
Real Estate Revenue	**67**	66	1
Total Revenue	**231**	226	5
Earnings	**23**	26	(3)

Factors Contributing to Revenue Variance

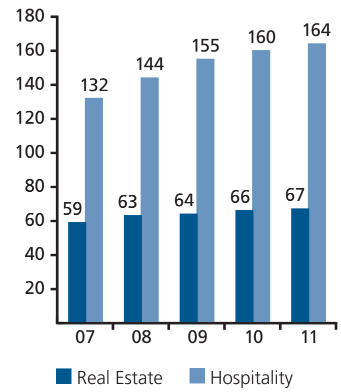
Favourable

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

Unfavourable

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

Fortis Properties Revenue *($ millions)*



Factors Contributing to Earnings Variance

Unfavourable

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

Favourable

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

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

The Real Estate Division is expected to produce stable results in 2012. The Real Estate Division operates primarily in Atlantic Canada, where the majority of properties are located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates that reduce the risk of vacancy exposure.

Corporate and Other

Financial Highlights

Years Ended December 31

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

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

Factors Contributing to Net Corporate and Other Expenses Variance

Favourable

- Higher other income, net of expenses, due to: (i) a $17 million (US$17.5 million) ($11 million after-tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS; and (ii) a $4.5 million foreign exchange gain associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity. The foreign exchange gain was partially offset by a $3.5 million ($3 million after-tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated debt. The favourable net impact to 2011 earnings of the above foreign exchange impacts was approximately $1.5 million. Business development costs of approximately $6 million ($4 million after tax) incurred in the first half of 2010 also had a favourable impact on other income, net of expenses, year over year.
- Lower finance charges due to the refinancing of maturing corporate debt at lower rates, the repayment of credit facility borrowings during the third quarter of 2011 with a portion of the proceeds from the common share offering in June and July 2011, and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense.

Unfavourable

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

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

REGULATORY HIGHLIGHTS

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

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2010	2011	2012	Supportive Features / Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	BCUC	40	9.50	9.50	9.50 (1)	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40	10.00	10.00	10.00 (1)	ROEs established by the BCUC
FEWI	BCUC	40	10.00	10.00	10.00 (1)	Future Test Year
FortisBC Electric	BCUC	40	9.90	9.90	9.90 (1)	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC Future Test Year
FortisAlberta	AUC	41	9.00	8.75	8.75	COS/ROE ROE established by the AUC Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.00 +/– 50 bps	8.38 +/– 50 bps	8.38 (2) +/– 50 bps	COS/ROE The allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. The formula has been suspended for 2012. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year
FortisOntario	Ontario Energy Board ("OEB")					
	Canadian Niagara Power	40	8.01	8.01	8.01 (3)	Canadian Niagara Power – COS/ROE
	Algoma Power	40	8.57	9.85	9.85 (3)	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Franchise Agreement					
	Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2009 test year for 2010, 2011 and 2012 Algoma Power – 2007 historical test year for 2010; 2011 test year for 2011 and 2012
				ROA		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 – 9.75	7.75 – 9.75	7.75 – 9.75 (4)	Rate-cap adjustment mechanism ("RCAM") based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings to the Interim Government of the Turks and Caicos Islands ("Interim Government")	N/A	17.50 (5)	17.50 (5)	17.50 (5)	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

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

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

(3) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 9.42% for 2012. This ROE is not applicable to the regulated electric utilities until they are scheduled to file full COS rate applications. As a result, the allowed ROE of 9.42% is not applicable to Canadian Niagara Power or Algoma Power in 2012.

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

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

Material Regulatory Decisions and Applications

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

Material Regulatory Decisions and Applications (cont'd)

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

Material Regulatory Decisions and Applications (cont'd)

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

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• In December 2011 the PUB approved Newfoundland Power's application requesting the adoption of US GAAP, effective January 1, 2012, for regulatory reporting purposes. • In December 2011 the PUB approved, as filed, Newfoundland Power's 2012 Capital Expenditure Plan totalling approximately $77 million. • In November 2011 Newfoundland Power's allowed ROE for 2012 was calculated at 7.85% under the ROE automatic adjustment formula, a decrease from 8.38% for 2011. In December 2011 the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 and to review cost of capital for 2012. As a result, current customer rates and the allowed ROE of 8.38% will continue in effect for 2012 on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012. • Newfoundland Power's midyear rate base for 2012 is forecast at $879 million. • The Company is currently assessing the requirement for it to file a general rate application with the PUB to recover increased costs in 2013.
Maritime Electric	• In November 2010 Maritime Electric signed the Accord with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by IRAC, incremental replacement energy costs totalling approximately $47 million incurred by Maritime Electric during the refurbishment of Point Lepreau up to the end of February 2011 were deferred. The deferred costs are included in rate base. For further information on Maritime Electric's contractual obligations with respect to Point Lepreau, refer to the "Contractual Obligations" section of this MD&A. • The nature and timing of the recovery of the deferred costs related to Point Lepreau is to be determined by the PEI Energy Commission (the "PEI Commission"), which was established by the Government of PEI in 2011. Having authority under the *Public Inquiries Act*, the co-chaired five-member PEI Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, among other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year PPA between Maritime Electric and NB Power, customer electricity rates decreased overall by approximately 14%, effective March 1, 2011, reflecting a decrease in the Energy Cost Adjustment Mechanism ("ECAM") and base component of rates. A two-year customer rate freeze commenced after the March 1, 2011 rate adjustment. The allowed ROE for 2011 and 2012 is 9.75%, as set under the terms of the Accord. • Maritime Electric intends to file an application with IRAC in fall 2012 for 2013 customer rates and allowed ROE.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation IRM as prescribed by the OEB. In March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflected an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an average customer's electricity bill, including rate riders and other charges, was an overall increase of 3.8%. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program. Algoma Power consulted with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. The balance of Algoma Power's revenue requirement is recovered from the RRRP Program. In September 2011 Algoma Power filed its first Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The Third-Generation IRM maintains the allowed ROE at 9.85%. Algoma Power has proposed that both electricity rates and funding under the RRRP Program be indexed through a price-cap formula. In December 2011 the OEB approved current customer rates as interim rates for 2012 for Algoma Power, pending a final decision on Algoma Power's rate application. In its March 2012 rate decision, the OEB approved a price cap index of 2.81% for customers subject to RRRP funding and 0.38% for those customers not subject to RRRP funding. RRRP funding for 2012 has been set at approximately $11 million. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase is subject to OEB approval.

Material Regulatory Decisions and Applications (cont'd)

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

CONSOLIDATED FINANCIAL POSITION

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

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

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

Summary of Consolidated Cash Flows

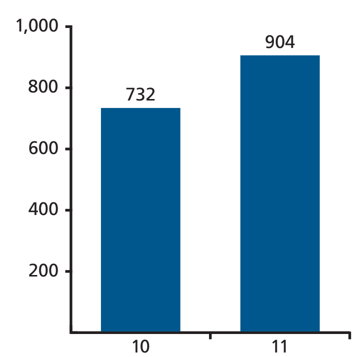
Years Ended December 31

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

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

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

Cash Flow from Operating Activities
($ millions)



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

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

Net repayment of short-term borrowings was $198 million in 2011 compared to $56 million for 2010. The increase in the repayment of short-term borrowings was driven by the FortisBC Energy companies, Maritime Electric and Caribbean Utilities.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations, and net borrowings (repayments) under committed credit facilities for 2011 compared to 2010 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

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

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

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

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

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

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

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

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

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

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

Repayments of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

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

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

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	2011	2010	Variance
FortisAlberta	**6**	1	5
FortisBC Electric	**9**	(35)	44
Newfoundland Power	**5**	1	4
Corporate	**(165)**	41	(206)
Total	**(145)**	8	(153)

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

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

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of approximately $300 million. In July 2011 an additional 1.2 million common shares were publicly issued upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million. The total net proceeds of $327 million from the common share offering were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion, in support of infrastructure investment, and for general corporate purposes.

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

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

Common share dividends paid in 2011 totalled $151 million, net of $59 million in dividends reinvested, compared to $135 million, net of $58 million in dividends reinvested, paid in 2010. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.16 in 2011 compared to $1.12 in 2010. The weighted average number of common shares outstanding was 181.6 million for 2011 compared to 172.9 million for 2010.

Contractual Obligations

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

Contractual Obligations

As at December 31, 2011 *($ millions)*	Total	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt (1)	**5,788**	103	791	440	4,454
Waneta Partnership promissory note (2)	**72**	–	–	–	72
Brilliant Terminal Station ("BTS") (3)	**87**	3	6	6	72
Gas purchase contract obligations (4)	**300**	180	120	–	–
Power purchase obligations					
FortisBC Electric (5)	**2,430**	47	85	81	2,217
FortisOntario (6)	**413**	48	99	103	163
Maritime Electric (7)	**190**	50	78	48	14
Capital cost (8)	**461**	17	36	36	372
Joint-use asset and shared service agreements (9)	**64**	3	8	7	46
Office lease – FortisBC Electric (10)	**17**	2	4	2	9
Operating lease obligations (11)	**152**	26	33	32	61
Defined benefit pension funding contributions (12)	**58**	26	28	2	2
Other (13)	**22**	3	8	7	4
Total	**10,054**	508	1,296	764	7,486

(1) In prior years, FEVI received non-interest bearing repayable loans from the federal government and Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates. As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the contractual obligations table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

(2) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion.

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

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

(5) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. Additionally, in November 2011, FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount estimated to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount has not been included in the Contractual Obligations table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

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

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

(8) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of the agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

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

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

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

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

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

Other Contractual Obligations: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The gross consolidated capital program of the Corporation, including capital spending at the non-regulated operations, is forecast to be approximately $1.3 billion for 2012, which is not included in the Contractual Obligations table above.

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

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

Capital Structure

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

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

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

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

(2) Includes preference shares classified as both long-term liabilities and equity

(3) Excludes amounts related to non-controlling interests

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

Credit Ratings

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

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

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

Capital Expenditure Program

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $98 million in maintenance and repairs was expensed in 2011 compared to approximately $96 million in 2010.

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

Gross Consolidated Capital Expenditures [(1)]

Year Ended December 31, 2011

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

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures were permissible in rate base in 2011.

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

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

Gross consolidated capital expenditures of $1,174 million for 2011 were $38 million lower than $1,212 million forecast for 2011, as disclosed in the MD&A for the year ended December 31, 2010. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts. Lower-than-forecasted capital spending was mainly due to: (i) a shift in the timing of certain capital expenditures from 2011 to 2012 and various small capital projects determined to be not required at the FortisBC Energy companies; (ii) the discontinuance of the consolidation method of accounting for Belize Electricity, effective June 2011; and (iii) a shift in capital expenditures from 2011 to 2012 related to the timing of payments associated with the Waneta Expansion.

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

Forecast Gross Consolidated Capital Expenditures [(1)]

Year Ending December 31, 2012

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

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

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

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

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

Gross Consolidated Capital Expenditures

Year Ending December 31 *(%)*	**Actual 2011**	Forecast 2012
Growth	**44**	40
Sustaining [(1)]	**30**	33
Other [(2)]	**26**	27
Total	**100**	100

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

(2) Relates to facilities, equipment, vehicles, information technology systems and other assets, including AESO transmission-related capital expenditures at FortisAlberta and the Customer Care Enhancement Project at FEI.

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

Significant Capital Projects [(1)]

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

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

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

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

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

FEI's Customer Care Enhancement Project, at an estimated total project cost of $110 million, came into service in January 2012. The Company estimates approximately $30 million of the project cost to be incurred in the first half of 2012 related to final contractor payments, with the total project cost expected to come in under budget. The project entailed the insourcing of core elements of FEI's customer care services, including two Company-owned call centres and billing operations, and implementation of a new customer information system. The BCUC approved the project upon the Company's acceptance of a cost risk-sharing condition, whereby FEI agreed to equally share with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost.

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

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

During 2011 FortisAlberta continued the replacement of vintage poles under its Pole Management Program, which involves 96,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through to 2019 is now expected to be approximately $335 million, an increase from the $283 million forecast as at December 31, 2010. The increase is primarily due to a revised forecast estimating higher labour and material costs later in the program and a change in the program scope to include minor-line rebuilds.

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

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

The Environmental Compliance Project at FortisBC Electric relates to work required to ensure compliance of the utility's substation equipment with the *Canadian Environmental Protection Act PCB Regulations (SOR/2008-273)* by 2014. The project is estimated to cost approximately $28 million through to 2014. Regulatory approval was obtained for 2011 costs with the remaining project costs subject to BCUC approval.

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

Construction progress on the $900 million 335-MW Waneta Expansion, in partnership with CPC/CBT, is going well and the project is currently on schedule. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Major construction activities on-site include the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $244 million has been spent on the Waneta Expansion since construction began late in 2010. The Waneta Expansion will be included in the amended and restated Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, is expected to be sold to FortisBC Electric under a long-term capacity purchase agreement. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table above, includes capitalized interest of Fortis during construction and a $72 million payment expected to be made in 2020 related to certain intangible assets and project design costs previously incurred by CPC/CBT. The table above excludes forecast capitalized interest of the Corporation's partners, CPC/CBT.

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

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

Cash Flow Requirements

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

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The subsidiaries expect to be able to source the cash required to fund their 2012 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be $103 million in 2012 and to average approximately $270 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For a further discussion of the Exploits Partnership, refer to the "Key Trends and Risks – Expropriated Assets" section of this MD&A.

Except for the debt at the Exploits Partnership, as described above, Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2011 and are expected to remain compliant in 2012.

Credit Facilities

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

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

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

Credit Facilities

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

As at December 31, 2011 and 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

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

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

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

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

In June 2011 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility to August 2015 from August 2013. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In August 2011 the Corporation renegotiated and amended its unsecured committed revolving credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the maturity date of the facility to July 2015 from May 2012. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In September 2011 FortisAlberta amended its unsecured committed revolving credit facility to increase the amount available under the facility to $250 million from $200 million and extend the maturity date to September 2015 from May 2012. The amended credit facility agreement reflects an increase in pricing.

In November 2011 FEVI renegotiated and amended its unsecured committed revolving credit facility, decreasing the amount available under the facility from $300 million to $200 million and extending the maturity date of the facility to December 2013 from May 2012. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

OFF-BALANCE SHEET ARRANGEMENTS

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

BUSINESS RISK MANAGEMENT

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

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

Approximately 93% of the Corporation's operating revenue was derived from regulated utility operations in 2011 (2010 – 93%), while approximately 89% of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2011 (2010 – 87%). Regulated utility assets comprised approximately 91% of total assets of Fortis as at December 31, 2011 (December 31, 2010 – 92%). The Corporation's regulated utilities primarily operate under COS methodologies. The utilities are subject to the normal uncertainties faced by regulated entities, including approval by the respective regulatory authority of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, the continuation of licences. Generally, the ability of the utilities to recover the actual costs of providing services and to earn the approved ROEs and/or ROAs is impacted by achieving the forecasts established in the rate-setting processes. Upgrades of, and additions to, gas and electricity infrastructure require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS.

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

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

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

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

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

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

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

FEI, FEVI, FEWI and FortisBC Electric are regulated by the BCUC and have used PBR mechanisms from time to time. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. The PBR mechanism at FortisBC Electric expired at the end of 2011 and the PBR mechanism at FEI expired at the end of 2009, with a two-year phase-out to the end of 2011. Upon expiry of PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be. FortisBC Electric and the FortisBC Energy companies have filed full COS applications for 2012 and 2013 rates with no assumption of PBR.

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

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

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

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

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory determined or negotiated process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. The formulaic ROE automatic adjustment mechanisms tied to long-term Canada bond rates, used in recent years at the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power, had resulted in lower allowed ROEs. A significant decline in interest rates and their impact on allowed ROEs could adversely affect the financial condition and results of operations of the Corporation's regulated utilities.

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

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

As at December 31, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2011.

Total Debt

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

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

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2011, is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates, as that change would have affected 2011 financial results, is disclosed in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

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

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

The Corporation's utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. The failure to do so may disrupt the ability of the utilities to safely distribute gas and electricity, which could have a material effect on the operations of the utilities.

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

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

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

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

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

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

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

Fortis also holds investments in both commercial office and retail space and hotel properties, with those assets representing 4% of the Corporation's total assets. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 9% per annum over the next five years. Approximately 56% of Fortis Properties' operating income was derived from hotel investments in 2011 (2010 – 55%). Organic revenue and earnings growth at Fortis Properties' Hospitality Division has been low in recent years, due to challenging economic conditions and the overall impact on leisure and business travel and hotel stays. Occupancy increases, however, were achieved in 2011 at the Company's hotel operations in Atlantic Canada and central Canada, but were more than offset by occupancy decreases experienced in western Canada. It is estimated that a 10% decrease in revenue at Fortis Properties' Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

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

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its larger subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and the financial position of the Corporation and the subsidiaries, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) may not be sufficient to fund the repayment of all outstanding liabilities when due, as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

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

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

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The $800 million committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes and may be increased to $1 billion at any time prior to maturity upon written notice by Fortis. As at December 31, 2011, Fortis had approximately $2.2 billion in consolidated credit facilities, of which $2.1 billion is committed with maturities ranging from 2012 through 2015. Approximately $1.9 billion of the credit facilities were unused as at December 31, 2011. No amounts were drawn on the corporate credit facility at as December 31, 2011.

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

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

Further information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

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

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

As at February 29, 2012, Belize Electricity owed BECOL US$7.5 million for overdue energy purchases, representing almost one-third of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Weather and Seasonality Risk: The physical assets of the Corporation and its subsidiaries could be exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At FEI a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing FEI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers.

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

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

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

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

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

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

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

Commodity Price Risk: The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility. In the past, the FortisBC Energy companies employed a number of tools to reduce exposure of commodity rates charged to customers to natural gas price volatility. Prior to mid-2011, these tools included hedging strategies based on a combination of both physical and financial transactions. As ordered by the BCUC, the FortisBC Energy companies discontinued most hedging activities by mid-2011, with existing hedges being managed to expiry. The use of natural gas derivatives effectively fixes the price of natural gas purchases and any resulting gains or losses effectively accrue entirely to customers. The absence of hedging activities may cause an increase in natural gas price volatility as this affects customer rates.

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

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

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

The Corporation's earnings from, and net investment in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on self-sustaining foreign net investments, which are also recognized in other comprehensive income. As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining foreign net investments remaining to be hedged.

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

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

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

Counterparty Risk: The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including existing natural gas commodity swaps and options. The FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit approval practices. The FortisBC Energy companies did not experience any counterparty defaults in 2011 and do not expect any counterparties to fail to meet their obligations. As events in the recent past have indicated, however, the credit quality of counterparties can change rapidly.

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

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since the majority of electricity prices in British Columbia were set based on the historical average cost of production (primarily associated with hydroelectric generation), rather than based on market forces, the competitive advantage of natural gas was substantially eroded during the decade that followed. More recently, however, there is potentially significant new investment in the electricity generation and transmission sector in British Columbia, which may put upward pressure on electricity rates. Furthermore, the growth in natural gas supply, due to the productivity and cost improvements associated with shale gas production, and subsequent decline in market natural gas prices, have helped to improve natural gas competitiveness on an operating basis. However, differences in upfront capital costs between electric-heated homes and natural gas-heated homes present a challenge for the competitiveness of natural gas on a full-cost basis. Further, there are other competitive factors that are impacting the penetration of natural gas in new housing builds, such as the green attributes of the energy source, government policy and the type of housing being built. A reduction in natural gas supply, due to low market prices and increased industrial and commercial demand due to stronger economic growth, are factors that may lead to materially higher market gas prices and volatility. In the future, if natural gas pricing becomes uncompetitive with pricing for electricity and other alternative energy sources, the ability of the FortisBC Energy companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and could, in an extreme case, ultimately lead to an inability to fully recover COS of the FortisBC Energy companies in rates charged to customers. Refer also to the "Business Risk Management – Risks Related to FEVI" and "Environmental Risks" sections of this MD&A.

Natural Gas, Fuel and Electricity Supply: The FortisBC Energy companies are dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas, where the majority of the natural gas distribution customers of the FortisBC Energy companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the FortisBC Energy companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the FortisBC Energy companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The addition of the new LNG storage facility on Vancouver Island, however, provides short-term supply during cold weather conditions or emergency situations.

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

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

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

In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion, the 335-MW hydroelectric generating facility currently under construction adjacent to the existing Waneta hydroelectric generating facility on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership between Fortis, which owns a 51% controlling interest, and CPC/CPT, which own a 49% minority interest. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010 and an executed version of the agreement was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of filing of the executed agreement.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of FHI, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees. Approximately 60% of the above utilities' total employees are members of such plans.

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

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

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

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

The above-noted risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power, actual net pension cost above or below the forecast net pension cost approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. There can be no assurance that net pension cost deferral mechanisms that were approved by the BCUC to the end of 2011 for the FortisBC Energy companies and FortisBC Electric will continue in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through net pension costs in customer rates could materially impact the results of operations, financial position and cash flows of the regulated utilities. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta, Newfoundland Power and FortisOntario are closed to all new employees.

Risks Related to FEVI: FEVI operates in the price-competitive service area of Vancouver Island, with a customer base and revenue that are currently sufficient to meet the Company's current COS. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement provided royalty revenue from the Government of British Columbia that covered approximately 20% of FEVI's COS. The royalty revenue expired at the end of 2011, after which time FEVI's customers began absorbing the full commodity cost of natural gas and all other COS. The Company has requested the continuation of the Rate Stabilization Deferral Account mechanism in its 2012–2013 Revenue Requirements Application, which allows FEVI to accumulate the recovery of costs from customers above FEVI's COS. Also, the remaining $49 million of outstanding non-interest bearing government loans, which is currently treated as a government contribution against rate base, is expected to be repaid by the end of 2016. As the debt is repaid, the higher rate base will increase COS and customer rates. With the cessation of royalty revenue and repayment of the government loans, the resultant increase in customer rates, as compared to electricity or alternative forms of energy, may make gas less competitive on Vancouver Island over time.

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

The management of GHG emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act*. The Energy Plan, released in 2007, is a natural progression from the previous plan, with a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature amending the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act,* which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. Specifically, the *Clean Energy Act* outlines 16 energy objectives for British Columbia, including the objective to have 93% of British Columbia's electricity generated from clean or renewable resources, to take demand-side measures and to conserve energy to meet a minimum of 66% of the expected increase in BC Hydro's demand for electricity by the year 2020, and to become a net exporter of electricity generated from clean or renewable resources. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2010 the FortisBC Energy companies began reporting and had external verification of GHG emissions generated by its facilities, as required under the *Greenhouse Gas Reduction (Cap and Trade) Act.* While a cap and trade program associated with GHG emissions was expected to begin on January 1, 2012, the Government of British Columbia has delayed the development of this regulatory initiative. If implemented, the cap and trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amount.

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

In 2011 Canada announced its decision to invoke its legal right to formally withdraw from the Kyoto Protocol. It is uncertain as to what impact this withdrawal may have going forward.

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

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

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

The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs can arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages could become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2011, there were no material environmental liabilities recognized in the Corporation's 2011 Consolidated Financial Statements. Also, there were no material unrecorded environmental liabilities known to management, except for the possibility of liabilities associated with various contingencies as discussed in the "Critical Accounting Estimates – Contingencies" section of this MD&A. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

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

Each of the utilities of Fortis has an Environmental Management System ("EMS"), with the exception of Fortis Turks and Caicos which expects to complete the implementation of its EMS in 2013. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge on environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

During 2011 direct costs arising from environmental protection, compliance, damages and carrying out the EMSs were not material to the Corporation's consolidated results of operations, cash flows or financial position. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable.

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

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

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

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

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

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the results of operations, cash flows and financial position of FortisAlberta.

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

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

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

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

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

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

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

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

In August 2011 the Government of Canada introduced additional legislative proposals relating to the taxation of multinationals. These changes recommend new rules relating to upstream loans and propose a new regime for the repatriation of capital. The upstream loans, i.e., loans made from a foreign affiliate to its parent, will now be required to be repaid within two years, after which time the loans will be included in the taxable income of the Canadian parent. Fortis uses upstream interest-free loans from its Caribbean subsidiaries as a tax-deferred repatriation of earnings. As at December 31, 2011, the Corporation had approximately $68 million of upstream loans that will now have to be repaid before December 31, 2013, at which time any outstanding balance will be included in the Corporation's taxable income. The Corporation also had approximately $18 million in downstream loans, as at December 31, 2011, that can be used to offset the impacts of having to repay the upstream loans.

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

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

Information Technology Infrastructure Risk: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information; and support the financial and general operating aspects of their business. System failures could have a material adverse effect on the utilities, such as the inability to provide energy to customers.

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

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

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

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

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

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

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

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

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

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

FUTURE ACCOUNTING CHANGES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FINANCIAL INSTRUMENTS

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

Financial Instruments

As at December 31	**2011**		2010	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**45**	**49**	42	40
Long-term debt, including current portion (1)	**5,788**	**7,143**	5,669	6,431
Preference shares, classified as debt (2)	**320**	**348**	320	344

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

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

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

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

From time to time the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

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

Derivative Financial Instruments

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

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

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

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to temper gas price volatility on customer rates and to reduce the risk of regional price discrepancies. For further information refer to the "Business Risk Management – Commodity Price Risk" section of this MD&A.

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

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

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

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Certain amounts are recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings.

Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. As at December 31, 2011, Fortis recognized $1,195 million in current and long-term regulatory assets (December 31, 2010 – $1,095 million) and $601 million in current and long-term regulatory liabilities (December 31, 2010 – $527 million).

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2011, the Corporation's consolidated utility capital assets, income producing properties and intangible assets totalled approximately $9.6 billion, or approximately 71% of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangible assets totalling approximately $9.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2010. The increase in capital assets was primarily associated with capital expenditures, which totalled approximately $1.2 billion in 2011. Amortization costs for 2011 were $419 million compared to $410 million for 2010. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization costs.

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

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

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

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

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. Fair market value is determined using net present value financial models and management's assumption of the future profitability of the reporting units. As at October 1 of each year, the Corporation reviews for impairment of goodwill. There was no impairment provision required on approximately $1.6 billion of goodwill recognized on the Corporation's consolidated balance sheet as at December 31, 2011.

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

The expected weighted-average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2012, is 6.76%, which is down slightly from 6.88% used in 2011. The defined benefit pension plan assets experienced total positive returns of approximately $42 million in 2011 compared to expected positive returns of $47 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed weighted-average discount rate used to measure the accrued pension benefit obligations on the applicable measurement dates in 2011 and determine net pension cost for 2012 is 4.65%, compared to the assumed weighted-average discount rate used to measure the accrued pension benefit obligations in 2010 and determine net pension cost for 2011 of 5.37%. The decrease in the assumed weighted-average discount rate is mainly due to lower credit risk spreads and cost of capital on investment-grade corporate bonds. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

There was a $7 million increase in consolidated defined benefit net pension cost for 2011 compared to 2010, mainly as a result of the impact of lower assumed discount rates for calculating net pension cost in 2011 compared to 2010 and the amortization of net actuarial losses that arose in prior years.

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

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recognized in the Corporation's 2011 Consolidated Financial Statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

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

Year Ended December 31, 2011

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

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

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

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

As approved by the respective regulator, the cost of OPEB plans at FortisAlberta, and at Newfoundland Power until December 31, 2010, is recovered in customer rates based on the cash payments made. The cost of defined benefit pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being recovered in customer rates based on the accrual method of accounting for OPEBs. As discussed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the FortisBC Energy companies and FortisBC Electric, and Newfoundland Power beginning in 2011, have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above deferral mechanism at the FortisBC Energy companies and FortisBC Electric will continue in the future as it is dependent on future regulatory decisions and orders.

As at December 31, 2011, for all defined benefit and OPEB plans, the Corporation had a consolidated accrued benefit asset of $87 million (December 31, 2010 – $94 million) and a consolidated accrued benefit liability of $168 million (December 31, 2010 – $157 million). During 2011 the Corporation recognized a consolidated net benefit cost of $54 million (2010 – $38 million) for all defined benefit and OPEB plans.

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, there were no amounts recognized as at December 31, 2011 and 2010, with the exception of AROs recognized by FortisBC Electric.

As at December 31, 2011, FortisBC Electric has recognized an approximate $4 million ARO (December 31, 2010 – $3 million) associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment, which has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating FortisBC Electric's ARO represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. The ARO may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2011, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

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

Revenue Recognition: Revenue at the Corporation's regulated utilities is recognized on an accrual basis. Gas and electricity consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically, usually monthly, and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2011, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $341 million (December 31, 2010 – $342 million) on annual consolidated revenue of approximately $3,747 million for 2011 (2010 – $3,657 million).

Capitalized Overhead: As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utiltiies and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but do relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

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

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

FHI

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

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric, dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2011, 2010 and 2009. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected for non-regulated entities.

Selected Annual Financial Information

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

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

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

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

2011/2010: Revenue increased $90 million, or 2.5%, over 2010 and net earnings attributable to common equity shareholders grew to $318 million, up $33 million from 2010. For a discussion of the reasons for the increases in revenue and net earnings attributable to common equity shareholders year over year, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A. The growth in total assets was primarily due to the Corporation's continued investment in energy infrastructure, driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2011 of committed credit facility borrowings, classified as long term, with a portion of the proceeds from the $341 million public common equity offering. The increases in total assets and long-term debt were partially offset by the impact of the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility in 2011. Basic earnings per common share increased 10 cents, or 6%, from 2010, mainly due to increased earnings, partially offset by the impact of an increase in the weighted average number of common shares outstanding, mainly associated with the public common equity offering in 2011. Dividends declared per common and preference shares for 2011 decreased from 2010 as a result of the timing of the declaration of dividends, partially offset by a 3.4% increase in the quarterly common share dividend declared in the fourth quarter of 2011. First quarter 2010 dividends were declared in January 2010, when normally they would have been declared in the fourth quarter of the preceding year, resulting in five quarters of dividends per common share being declared in 2010.

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

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the quarters ended December 31, 2011 and 2010. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. A discussion of the financial results for the fourth quarter of 2011 is also contained in the Corporation's fourth quarter 2011 media release, dated and filed on SEDAR at www.sedar.com on February 9, 2012, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue Fourth Quarters Ended December 31 *(Unaudited)*	**Gas Volumes Energy and Electricity Sales**			**Revenue** *($ millions)*		
	2011	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
FortisBC Energy Companies	**62,753**	60,398	2,355	**477**	479	(2)
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,232**	4,255	(23)	**102**	99	3
FortisBC Electric	**843**	847	(4)	**81**	73	8
Newfoundland Power	**1,527**	1,488	39	**156**	152	4
Other Canadian Electric Utilities	**568**	578	(10)	**84**	87	(3)
	7,170	7,168	2	**423**	411	12
Regulated Electric Utilities – Caribbean	**174**	270	(96)	**70**	84	(14)
Non-Regulated – Fortis Generation	**112**	137	(25)	**9**	9	–
Non-Regulated – Fortis Properties				**58**	57	1
Corporate and Other				**7**	7	–
Inter-Segment Eliminations				**(7)**	(13)	6
Total				**1,037**	1,034	3

Factors Contributing to Gas Volumes Variance

Favourable

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

Unfavourable

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

Factors Contributing to Energy and Electricity Sales Variances

Unfavourable

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

Favourable

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

Factors Contributing to Revenue Variance

Favourable

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

Unfavourable

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

Segmented Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*

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

Factors Contributing to Earnings Variance

Favourable

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

Unfavourable

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

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

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

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

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

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

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2010 through December 31, 2011. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements, which have been prepared in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share **Basic** *($)*	**Diluted** *($)*
December 31, 2011	1,037	86	0.46	0.45
September 30, 2011	702	57	0.31	0.31
June 30, 2011	849	58	0.33	0.33
March 31, 2011	1,159	117	0.67	0.65
December 31, 2010	1,034	85	0.49	0.47
September 30, 2010	719	45	0.26	0.26
June 30, 2010	834	55	0.32	0.32
March 31, 2010	1,070	100	0.58	0.56

A summary of the past eight quarters mainly reflects the Corporation's continued organic growth, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Earnings for the third quarter ended September 30, 2011 included the $11 million after-tax termination fee paid to Fortis by CVPS. Financial results for the fourth quarter ended December 31, 2011 reflected the acquisition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011. Financial results from June 20, 2011 reflected the discontinuance of the consolidation method of accounting for Belize Electricity due to the expropriation of the utility by the GOB. For further information, refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of this MD&A. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with the 2010 revenue requirements decision at FortisAlberta. The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since that date.

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

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

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

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

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

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2011 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2011 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2011, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing ("the Acquisition"). CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the Acquisition, which is expected in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

OUTLOOK

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

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

OUTSTANDING SHARE DATA

As at March 12, 2012, the Corporation had issued and outstanding 189.3 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; and 10.0 million First Preference Shares, Series H. Only the common shares of the Corporation have voting rights.

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

Conversion of Securities into Common Shares

As at March 12, 2012 *(Unaudited)*

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

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

Financials

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Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2011 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2011 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

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

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

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2011 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2011 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2011 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

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

St. John's, Canada

Independent Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, retained earnings and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

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

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

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

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
March 13, 2012

Consolidated Balance Sheets

FORTIS INC.

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

As at December 31 (in millions of Canadian dollars)

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

Commitments *(Note 30)*

Contingent Liabilities *(Note 32)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2011**	2010
		(Note 34)
Revenue	**$ 3,747**	$ 3,657
Expenses		
Energy supply costs	**1,697**	1,686
Operating	**865**	822
Amortization	**419**	410
	2,981	2,918
Operating income	**766**	739
Other income (expenses), net *(Note 20)*	**40**	13
Finance charges *(Note 21)*	**370**	362
Earnings before corporate taxes	**436**	390
Corporate taxes *(Note 22)*	**80**	67
Net earnings	**$ 356**	$ 323
Net earnings attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**318**	285
	$ 356	$ 323
Earnings per common share *(Note 16)*		
Basic	**$ 1.75**	$ 1.65
Diluted	**$ 1.74**	$ 1.62

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

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

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
Net earnings	**$ 356**	$ 323
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and tax *(Note 18)*	**2**	(12)
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity *(Notes 8 and 18)*	**17**	–
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 18)*	**1**	1
	20	(11)
Comprehensive income	**$ 376**	$ 312
Comprehensive income attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**338**	274
	$ 376	$ 312

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
		(Note 34)
Operating activities		
Net earnings	**$ 356**	$ 323
Items not affecting cash:		
Amortization – utility capital assets and income producing properties	**380**	368
Amortization – intangible assets	**42**	40
Amortization – other	**(3)**	2
Future income taxes *(Note 22)*	**4**	(3)
Accrued employee future benefits	**18**	8
Equity component of allowance for funds used during construction *(Note 20)*	**(13)**	(15)
Other	**(4)**	2
Change in long-term regulatory assets and liabilities	**26**	9
	806	734
Change in non-cash operating working capital *(Note 26)*	**98**	(2)
	904	732
Investing activities		
Change in other assets and other liabilities	**(52)**	–
Capital expenditures – utility capital assets	**(1,086)**	(1,008)
Capital expenditures – income producing properties	**(30)**	(19)
Capital expenditures – intangible assets	**(58)**	(46)
Contributions in aid of construction	**75**	67
Proceeds on sale of utility capital assets and income producing properties *(Note 7)*	**51**	15
Business acquisition, net of cash acquired *(Note 24)*	**(25)**	–
	(1,125)	(991)
Financing activities		
Change in short-term borrowings	**(198)**	(56)
Proceeds from long-term debt, net of issue costs	**343**	523
Repayments of long-term debt and capital lease obligations	**(36)**	(329)
Net (repayments) borrowings under committed credit facilities	**(145)**	8
Net advances from non-controlling interests	**81**	45
Issue of common shares, net of costs and dividends reinvested	**345**	22
Issue of preference shares, net of costs	**–**	242
Dividends		
Common shares, net of dividends reinvested	**(151)**	(135)
Preference shares	**(29)**	(28)
Subsidiary dividends paid to non-controlling interests	**(9)**	(9)
	201	283
Change in cash and cash equivalents	**(20)**	24
Cash and cash equivalents, beginning of year	**109**	85
Cash and cash equivalents, end of year	**$ 89**	$ 109

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

See accompanying Notes to Consolidated Financial Statements

1. Description of the Business

Nature of Operations

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

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

Regulated Utilities

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

Regulated Gas Utilities – Canadian

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

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

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

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

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

Regulated Electric Utilities – Canadian

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

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

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

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies.

December 31, 2011 and 2010

1. Description of the Business (cont'd)

Regulated Utilities (cont'd)

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

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

c. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. Fortis held an approximate 70% controlling ownership interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011 (Notes 8 and 31).

Non-Regulated – Fortis Generation

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

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Includes six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Fortis Properties holds directly a 51% interest in the Exploits Partnership and Abitibi holds the remaining 49% interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement ("PPA") expiring in 2033. In December 2008 the Government of Newfoundland and Labrador expropriated the hydroelectric assets and water rights of the Exploits Partnership. As a result of no longer controlling the cash flows and operations of the Exploits Partnership, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership, effective February 2009 (Note 31).

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

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

Non-Regulated – Fortis Properties

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

Corporate and Other

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

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

2. Nature of Regulation

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

FortisBC Energy Companies and FortisBC Electric

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

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

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

Under the previous PBR mechanisms, FEI customers equally shared achieved earnings above or below the allowed ROE and FortisBC Electric customers equally shared achieved earnings above or below the allowed ROE up to an achieved ROE that was 200 basis points above or below the allowed ROE. Any excess was subject to deferral account treatment. FortisBC Electric's portion of the PBR incentive was subject to the Company meeting certain performance standards and BCUC approval. The BCUC-approved Negotiated Settlement Agreements for 2010 and 2011 for FEI and the 2012–2013 Revenue Requirements Applications for both FortisBC Electric and FEI did not include new PBR mechanisms.

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

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

2. Nature of Regulation (cont'd)

FortisAlberta

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

FortisAlberta operates under COS regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75% for 2011 (2010 – 9.00%) on a deemed capital structure of 41% common equity. The Company applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

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

Newfoundland Power

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

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

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

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

Maritime Electric

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

IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a targeted capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75% for 2011 (2010 – 9.75%) on a targeted minimum capital structure of 40% common equity.

In November 2010 Maritime Electric signed the Accord with the Government of PEI. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to Maritime Electric's 4.7% entitlement from the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. Maritime Electric also signed a five-year energy purchase agreement with NB Power, effective March 1, 2011. As a result of the Accord and the impact of the new energy purchase agreement, energy supply costs have decreased and customer electricity rates were lowered by approximately 14.0%, effective March 1, 2011, at which time a two-year customer rate freeze commenced.

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

FortisOntario
Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs.

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

Effective December 1, 2010, Algoma Power's allowed ROE was 9.85% on a deemed capital structure of 40% common equity and the utility's electricity distribution rates were rebased using forecast 2011 costs. Prior to December 1, 2010, the Company's allowed ROE was 8.57% on a deemed capital structure of 50% common equity and the utility's electricity distribution rates were based upon costs derived from a 2007 historical test year. Algoma Power is subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario.

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

Caribbean Utilities
Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The non-exclusive generation licence is for a period of 21.5 years, expiring September 2029.

The licences contain the provision for a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer electricity rates for 2011 were set in accordance with the licences, translating into a targeted allowed rate of return on rate base assets ("ROA") range of 7.75% to 9.75% (2010 – 7.75% to 9.75%). The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the RCAM and annually approves capital expenditures.

Fortis Turks and Caicos
Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through FortisTCI and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated January and October 1987, and November 1986 (collectively, the "Agreements"), respectively. Among other matters, the Agreements describe how electricity rates are to be set by the Interim Government of the Turks and Caicos Islands ("Interim Government"), using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.50% (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall").

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

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

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

3. Summary of Significant Accounting Policies

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

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

All amounts presented are in Canadian dollars unless otherwise stated.

Cash and Cash Equivalents

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

Regulatory Assets and Liabilities

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

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

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

Inventories

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

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated amortization, with the following exceptions for rate-setting purposes: (i) utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost; (ii) utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost; and (iii) utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions at Fortis Turks and Caicos are at cost, including the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by the Agreements for US$2.00, in aggregate, as valued in the books of the Companies.

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

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

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

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

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

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

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 5 *(viii)*).

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

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

As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, Fortis Turks and Caicos and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets but do relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million).

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

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

December 31, 2011 and 2010

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

Utility Capital Assets (cont'd)

As approved by the regulator, FEVI has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FEVI increases both utility capital assets and long-term debt (Note 30).

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

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

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

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

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

Income Producing Properties

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

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

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are amortized over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; and customer contracts.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually either individually or at the reporting unit level. Such intangible assets are not amortized. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

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

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

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

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

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval. In the absence of rate regulation, any loss on the retirement or disposal of intangible assets would be recognized in earnings in the period incurred.

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

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2011 and 2010.

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

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

Goodwill

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

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. The annual impairment test was performed as at October 1, 2011. No goodwill impairment provision has been determined for the years ended December 31, 2011 and 2010.

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

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans
The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees; and defined contribution pension plans, including group Registered Retirement Savings Plans ("RRSPs"), for employees. The accrued pension benefit obligation and the value of pension cost of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

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

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

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

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

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

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

Other Post-Employment Benefit Plans
The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits ("OPEBs") through defined benefit plans, including certain health and dental coverage, for qualifying members.

The accrued benefit obligation and the value of the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation at the beginning of the fiscal year and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

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

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

Stock-Based Compensation

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

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

Foreign Currency Translation

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

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of self-sustaining foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income.

Effective June 20, 2011, as a result of the expropriation of Belize Electricity by the GOB, the Corporation's asset associated with its previous investment in Belize Electricity (Notes 8 and 31) is no longer a self-sustaining foreign subsidiary of Fortis and, therefore, does not qualify for hedge accounting. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and any corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment are recognized in earnings.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Financial Instruments

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

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

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

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

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

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

Hedging Relationships

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

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

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

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

The fair values of the fuel option contracts, the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet date. As at December 31, 2011, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The Corporation's earnings from, and net investments in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on self-sustaining foreign net investments, which are also recognized in other comprehensive income.

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory balances for which deferred income tax is recovered or refunded in current customer rates, as prescribed by the respective regulator. Therefore, current customer rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. The above utilities recognize an offsetting regulatory asset or liability for the amount of future income taxes that are expected to be collected or refunded in customer rates once they become payable or receivable (Note 5 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher corporate income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs. Belize Electricity is subject to corporate tax under the *Income and Business Tax Act* (Belize). Up to April 1, 2010, corporate tax was capped at 1.75% of gross revenue. Effective April 1, 2010, the corporate tax rate increased to 6.50% of gross revenue. The additional 4.75% corporate tax was being deferred by Belize Electricity for recovery from customers in future electricity rates.

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

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

Revenue Recognition

Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

Revenue from the sale of gas by the FortisBC Energy companies and electricity by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on an accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

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

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with the Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. As approved by the regulator, FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers is deferred to be recovered from, or refunded to, customers in future rates (Note 5 *(vi)*). In the absence of rate regulation, deferral account treatment would not be permitted.

FortisOntario's regulated operations primarily consist of the operations of Cornwall Electric, Canadian Niagara Power and Algoma Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power and Algoma Power are not bundled. At Canadian Niagara Power and Algoma Power, the cost of power and/or transmission is a flow through to customers and revenue associated with the recovery of these costs is tracked and recorded separately. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

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

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

Revenue Recognition (cont'd)

The leases are primarily of a net nature, with tenants paying basic rent plus a pro-rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants are recorded as revenue. Base rent and the escalation of lease rates included in long-term leases are recognized in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations

Asset-retirement obligations ("AROs"), including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

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

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods.

Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Certain amounts are recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Income Producing Properties, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 5 and 32.

4. Future Accounting Changes

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

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

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

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

5. Regulatory Assets and Liabilities

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

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

December 31, 2011 and 2010

5. Regulatory Assets and Liabilities (cont'd)

Regulatory Liabilities

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

Description of the Nature of Regulatory Assets and Liabilities

(i) *Future Income Taxes*

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

(ii) *Rate Stabilization Accounts – FortisBC Energy Companies*

The rate stabilization accounts at the FortisBC Energy companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, natural gas cost volatility and changes in the fair value of natural gas commodity derivative instruments.

At FEI a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of FEI's natural gas commodity derivative instruments. At FEVI a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on FEVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in fair value of FEVI's natural gas commodity derivative instruments.

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

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

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

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

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

(iii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos) are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. The rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power, the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. The weather normalization account reduces the volatility in Newfoundland Power's year-to-year earnings that would otherwise result from fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, ranges from one to three years and is subject to periodic review by the respective regulatory authority.

The balance in Newfoundland Power's weather normalization account as at December 31, 2011 was a net regulatory liability of $7 million (December 31, 2010 – net regulatory liability of $3 million). The account balance should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB in 2008, a non-reversing asset balance of approximately $7 million of the weather normalization account is being amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recognized in earnings as incurred. The recovery period of the remaining balance of the weather normalization account is yet to be determined as it depends on weather conditions in the future.

As at December 31, 2011, $6 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of three years. Subsequent to 2003, annual deferral of energy costs to the ECAM account was recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period. In accordance with the PEI Energy Accord which came into effect on March 1, 2011, the balance of the ECAM regulatory liability of $21 million will be refunded to customers commencing in 2013 and, as a result, has been classified as long-term. The remaining settlement period of the post-2003 ECAM is to be determined at a future time.

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

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

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

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

(iv) Regulatory OPEB Plan Assets

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

(v) Point Lepreau Replacement Energy Deferral

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

(vi) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates.

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

(vii) Deferred Energy Management Costs

The FortisBC Energy companies, FortisBC Electric, Newfoundland Power and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, the above regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 4 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(viii) Deferred Losses on Disposal of Utility Capital Assets

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

(ix) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets. In the absence of rate regulation, the operating costs would be expensed in the period incurred and no deferral account treatment would be permitted.

(x) Income Taxes Recoverable on OPEB Plans

At FEI and FortisBC Electric, the regulator allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the regulator, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. In the absence of rate regulation, the income taxes would not be deferred.

(xi) *Whistler Pipeline Contribution Deferral*

The Whistler pipeline contribution deferral represents the capital contribution from FEWI to FEVI on completion of the natural gas pipeline to Whistler, as constructed by FEVI. The deferral is to be recovered from FEWI's customers over a period of 50 years, as approved by the regulator. In the absence of rate regulation, the capital contribution deferral would have been capitalized and amortized to earnings over the life of the asset.

(xii) *Customer Care Enhancement Project Cost Deferral*

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

(xiii) *Deferred Development Costs for Capital*

Deferred development costs for capital projects include costs for projects under development at the FortisBC Energy companies that are subject to regulatory approval for recovery in future customer rates. The majority of the balance relates to the project cost overrun incurred on the conversion of FEWI customer appliances from propane to natural gas, for which FEWI received a decision from the BCUC allowing these additional costs to be deferred and collected in FEWI customer rates. In the absence of rate regulation, the deferred development costs for capital would be capitalized; however, the ultimate period of amortization would likely differ.

(xiv) *Pension Cost Variance Deferral*

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

(xv) *Deferred Costs – Smart Meters*

In 2006 the Government of Ontario committed to install smart electricity meters in all Ontario residences and small commercial businesses by the end of 2010. FortisOntario is eligible to recover from customers in future customer rates all prudent and reasonable costs that were incurred related to this smart metering initiative. These deferred costs represent incremental operating, administrative and capital costs directly related to the smart metering initiative and are subject to regulatory approval. In the absence of rate regulation, these deferred costs would have been capitalized; however, the method of amortization to earnings would likely differ.

(xvi) *Alternative Energy Projects Cost Deferral*

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

(xvii) *Deferred Lease Costs*

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

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

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

(xviii) *2010 Accrued Distribution Revenue Adjustment Rider*

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

5. Regulatory Assets and Liabilities (cont'd)

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

(xix) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2011, $65 million (December 31, 2010 – $43 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2011, $10 million (December 31, 2010 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

(xx) Asset Removal and Site Restoration Provision

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

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

(xxi) Income Tax Variance Deferral

The income tax variance deferral account at the FortisBC Energy companies accumulates the difference in income tax expense as a result of changes in tax laws, audit reassessments, accounting policy changes and changes in income tax rates for refund to customers in future rates over a period of three years, as approved by the regulator. In the absence of rate regulation, deferral account treatment would not be permitted and the income tax variance would be reflected in earnings in the period the change occurred.

(xxii) Deferred Interest

The FortisBC Energy companies have interest deferral mechanisms, as approved by the regulator, which accumulate variances between actual and approved interest rates associated with long-term and short-term borrowings and between the actual and forecast interest calculated on the average balance of the MCRA account. The deferred interest will be refunded to customers in future rates over one to three years. In the absence of rate regulation, actual interest costs would have been expensed in the period incurred.

(xxiii) Southern Crossing Pipeline Deferral

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

(xxiv) PBR Incentive Liabilities

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

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

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

(xxvi) 2010 FEI Revenue Surplus

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

(xxvii) Unbilled Revenue Liability

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

(xxviii) Other Regulatory Liabilities

Other regulatory liabilities relate to the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2011, $25 million (December 31, 2010 – $21 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2011, $7 million (December 31, 2010 – $10 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

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

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

6. Inventories

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

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

7. Assets Held for Sale

In 2010 Bell Aliant Inc. ("Bell Aliant") exercised its option, under an agreement with Newfoundland Power, to buy back 40% of all joint-use poles owned by Newfoundland Power. In October 2011 Newfoundland Power received proceeds of approximately $46 million from Bell Aliant. The proceeds from the sale of the joint-use poles approximated net book value.

8. Other Assets

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

December 31, 2011 and 2010

8. Other Assets (cont'd)

As a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB and the consequential loss of control over the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's previously 70% controlled foreign net investment in Belize Electricity has been classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing as at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity does not qualify for hedge accounting and, as a result, from June 20, 2011, an approximate $4.5 million foreign exchange gain on the translation of the asset was recognized in earnings for 2011 (Note 20).

As at June 20, 2011, approximately $28 million of unrealized foreign currency translation losses related to the translation into Canadian dollars of the Corporation's previous foreign net investment in Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, were reclassified to long-term other assets from accumulated other comprehensive loss and were included in the $106 million balance as at December 31, 2011 (Note 18).

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

9. Utility Capital Assets

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

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

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

As at December 31, 2011, assets under construction associated with larger projects included the Waneta Expansion and AESO transmission-related capital projects at FortisAlberta.

The cost of utility capital assets under capital lease as at December 31, 2011 was $61 million (December 31, 2010 – $59 million) and related accumulated amortization was $26 million (December 31, 2010 – $25 million).

10. Income Producing Properties

2011

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

2010

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

11. Intangible Assets

2011

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

2010

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

December 31, 2011 and 2010

11. Intangible Assets (cont'd)

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

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

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

12. Goodwill

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

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

13. Long-Term Debt and Capital Lease Obligations

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

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

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

As identified in the table above, certain long-term debt instruments issued by FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Properties are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the company to which the long-term debt is associated.

Regulated Utilities

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

The majority of the long-term debt instruments at Regulated Utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

December 31, 2011 and 2010

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

Corporate – Fortis and FHI

The majority of the unsecured debentures and all of the US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

The US$40 million unsecured subordinated convertible debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 per share (US$29.11 per share) in November 2011, as permitted under the debt agreement (Note 16).

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

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2012	$ 106	$ –	$ 106
2013	97	–	97
2014	422	280	702
2015	152	–	152
2016	294	–	294
Thereafter	3,872	605	4,477

14. Other Liabilities

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

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2011, its discounted net present value was $45 million (December 31, 2010 – $42 million). The promissory note was incurred on the acquisition by the Waneta Partnership, from a company affiliated with CPC/CBT, of certain intangible assets and project design costs associated with the construction of the Waneta Expansion. The promissory note is payable on the fifth anniversary of the commercial operation date of the Waneta Expansion, which is projected to be in spring 2015.

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

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

15. Preference Shares

Authorized
(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding			**2011**		2010	
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**	10,000,000	245
Total classified as equity			**24,200,000**	**$ 592**	24,200,000	$ 592

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

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

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

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

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series C and Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series C and Series E for cash or arrange for the sale of those shares to other purchasers.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each preference share may be converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G and Series H are entitled to receive fixed cumulative preferential cash dividends in the amounts of $1.3125 and $1.0625 per share per annum, respectively, for each year up to but excluding September 1, 2013 and June 1, 2015, respectively. As at September 1, 2013 and June 1, 2015 and each five-year period thereafter, the holders of First Preference Shares, Series G and Series H, respectively, are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G and Series H, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13% and 1.45%, respectively.

On each Series H Conversion Date, the holders of First Preference Shares, Series H have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I. The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

16. Common Shares

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

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

Common shares issued during the year were as follows:

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

In June 2011 Fortis publicly issued 9.1 million common shares for $33.00 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses. In July 2011 an additional 1.24 million common shares of Fortis were publicly issued for $33.00 per share upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million, or approximately $40 million net of after-tax expenses.

The US$40 million unsecured subordinated convertible debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 per share (US$29.11 per share) in November 2011, as permitted under the debt agreement (Note 13).

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

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

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

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

Earnings per Common Share

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 181.6 million for 2011 and 172.9 million for 2010.

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

EPS were as follows:

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

17. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2011, the Corporation had the following stock option plans: the 2006 Plan and the 2002 Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to replace the former Executive Stock Option Plan ("ESOP") and the Directors' Stock Option Plan. All of the outstanding options under the former ESOP were exercised during 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options issued under this plan are exercised or expire in or before 2016. The Corporation ceased granting options under the 2002 Plan and all options granted after 2006 are under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

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

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

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

Stock Options (cont'd)

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

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

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

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

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

The fair values of the above option grants were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions.

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

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

Directors' DSU Plan

The Corporation's Directors' DSU Plan is an optional means for directors to elect to receive credit for their annual retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006 directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

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

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

During 2011 31,821 DSUs were paid out, subsequent to the death of a Board member, at a price of $33.06 per DSU, for a total of approximately $1 million.

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

PSU Plan

The Corporation's PSU Plan is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

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

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

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

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

18. Accumulated Other Comprehensive Loss

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive loss by category is provided as follows:

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

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

The net change in accumulated other comprehensive loss for 2011 includes the reclassification of $28 million of unrealized foreign currency translation losses, related to the translation into Canadian dollars of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in self sustaining Belize Electricity, to long-term other assets from accumulated other comprehensive loss. The reclassifications were the result of the expropriation of Belize Electricity on June 20, 2011 (Notes 8 and 31).

19. Non-Controlling Interests

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

20. Other Income (Expenses), Net

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

The termination fee was paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation.

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

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

21. Finance Charges

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

December 31, 2011 and 2010

22. Corporate Taxes

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

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

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

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

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

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

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

23. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group RRSPs for employees. The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and Algoma Power also offer OPEB plans for qualifying employees.

For the defined benefit pension plan arrangements, the accrued pension benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, the FortisBC Energy companies, Newfoundland Power and Caribbean Utilities, and as at September 30 of each year for FortisAlberta, FortisBC Electric, FortisOntario and Algoma Power. The most recent actuarial valuation of the pension plans for funding purposes was as of July 1, 2009 for Algoma Power; as of December 31, 2009 for the FortisBC Energy companies (covering non-unionized employees) and FortisOntario; as of December 31, 2010 for the FortisBC Energy companies (covering unionized employees), FortisAlberta and FortisBC Electric; and as of December 31, 2011 for the Corporation, Newfoundland Power and Caribbean Utilities. The next required valuations for funding purposes will be, at the latest, three years from the date of the most recent actuarial valuation of each plan, as noted above.

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

Plan assets as at December 31

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

December 31, 2011 and 2010

23. *Employee Future Benefits (cont'd)*

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

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

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

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

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

For 2011 the effects of changing the health-care cost trend rate by 1% were as follows:

(in millions)	1% increase in rate	1% decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 25**	**$ (21)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

December 31, 2011 and 2010

23. Employee Future Benefits (cont'd)

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

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

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

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

24. Business Acquisition

2011

NON-REGULATED – FORTIS PROPERTIES

In October 2011 Fortis Properties purchased the Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million, which was allocated to income producing properties. The acquisition has been accounted for using the purchase method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing October 2011.

25. Segmented Information

Information by reportable segment is as follows:

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

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

December 31, 2011 and 2010

25. Segmented Information (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011, and to FortisOntario; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) finance charges on related party borrowings. The significant related party inter-segment transactions during the years ended December 31 were as follows:

Significant Related Party Inter-Segment Transactions

(in millions)	2011	2010
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	$ 7	$ 24
Sales from Fortis Generation to Other Canadian Electric Utilities	1	1
Sales from Newfoundland Power to Fortis Properties	5	4
Inter-segment finance charges on borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	1	4
Corporate to Other Canadian Electric Utilities	2	1
Corporate to Regulated Electric Utilities – Caribbean	4	3
Corporate to Fortis Generation	3	4
Corporate to Fortis Properties	13	12

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

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

26. Supplementary Information to Consolidated Statements of Cash Flows

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

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

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

27. Capital Management

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

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

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

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

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2011, the Corporation and its subsidiaries, except for the Exploits Partnership, as described below, were in compliance with their debt covenants.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. See Note 31 for further information on the Exploits Partnership.

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

28. Financial Instruments

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

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

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

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

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

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

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

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

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

29. Financial Risk Management

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

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

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

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2011, its gross credit risk exposure was approximately $150 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the FortisBC Energy companies have significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

December 31, 2011 and 2010

29. Financial Risk Management (cont'd)

Credit Risk (cont'd)

The Corporation is exposed to credit risk associated with the amount and timing of compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. The Corporation has a long-term other asset of $106 million, including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 8 and 31).

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

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

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

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

Liquidity Risk

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

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

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $270 million. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

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

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

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

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

As at December 31, 2011 and 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

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

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

Regulated Utilities
FEI has a $500 million unsecured committed revolving credit facility, maturing August 2013. FEVI has a $200 million unsecured committed revolving credit facility, maturing December 2013. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes. FEVI also has a $20 million unsecured committed non-revolving credit facility, maturing January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

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

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2012 and the remaining $100 million matures May 2014. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand credit facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2015, and a $20 million demand credit facility.

Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing February 2014, and a $5 million unsecured demand credit facility.

FortisOntario has secured lines of credit totalling $20 million, of which $14 million is authorized solely for letters of credit.

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

Fortis Turks and Caicos has unsecured credit facilities of US$21 million ($21 million), comprised of a revolving operating credit facility of US$5 million ($5 million), a capital expenditure line of credit of US$7 million ($7 million) and a US$9 million ($9 million) emergency standby loan.

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

December 31, 2011 and 2010

29. Financial Risk Management (cont'd)

Liquidity Risk (cont'd)

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

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

The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing (Note 33), DBRS placed the Corporation's credit rating under review with developing implications. Similarly, Standard & Poor's placed the Corporation's credit rating on credit watch with negative implications.

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

Financial Liabilities

(in millions)	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years	**Total**
Short-term borrowings	$ 159	$ –	$ –	$ –	**$ 159**
Trade and other accounts payable	778	–	–	–	**778**
Natural gas derivatives [(1)]	88	41	–	–	**129**
Fuel option contracts [(2)]	1	–	–	–	**1**
Foreign exchange forward contract [(3)]	4	–	–	–	**4**
Dividends payable	60	–	–	–	**60**
Customer deposits [(4)]	–	2	1	3	**6**
Waneta Partnership promissory note [(5)]	–	–	–	72	**72**
Long-term debt, including current portion [(6)]	103	791	440	4,454	**5,788**
Interest obligations on long-term debt	356	690	597	5,201	**6,844**
Preference shares, classified as debt	–	123	197	–	**320**
Dividend obligations on preference shares, classified as finance charges	17	25	17	–	**59**
Total	$ 1,566	$ 1,672	$ 1,252	$ 9,730	**$ 14,220**

(1) Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2011 at $135 million.

(2) Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at $1 million.

(3) Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at less than $1 million.

(4) Customer deposits were recorded in other liabilities as at December 31, 2011.

(5) Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in other liabilities at discounted net present value as at December 31, 2011 at $45 million.

(6) Excludes deferred financing costs of $43 million and capital lease obligations of $40 million

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity (Note 8) does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. As a result, the Corporation recognized a net foreign exchange gain of approximately $1 million ($1.5 million after tax) in earnings in 2011 (Note 20).

A 5% appreciation or depreciation of the US dollar relative to the Canadian dollar would have: (i) increased or decreased earnings by approximately $6 million for the year ended December 31, 2011 (2010 – $2 million); (ii) increased or decreased long-term other assets by approximately $4 million as at December 31, 2011 (2010 – nil); and (iii) decreased or increased other comprehensive income by $24 million for the year ended December 31, 2011 (2010 – $25 million). This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense, earnings streams from the Corporation's foreign subsidiaries, the translation of the Corporation's long-term other asset associated with its previous investment in Belize Electricity, and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased or decreased other comprehensive income by $28 million for the year ended December 31, 2011 (2010 – $30 million).

FEI's US dollar payments under a contract for the implementation of a customer care information system are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2011, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar, as it impacts the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased or decreased earnings by less than $1 million for the year ended December 31, 2011 (2010 – less than $1 million). Furthermore, FEI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $3 million for the year ended December 31, 2011 (2010 – $4 million). A 25 basis point decrease in interest rates associated with variable-rate debt, with all other variables remaining constant, would have increased earnings by $1 million for the year ended December 31, 2011 (2010 – $1 million). Furthermore, the FortisBC Energy companies and FortisBC Electric have regulatory deferral accounts that mitigate exposure to fluctuations in interest rates associated with variable-rate debt and are recovered from, or refunded to, customers in future rates.

Certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by approximately $1 million for the year ended December 31, 2011 (2010 – $1 million).

Commodity Price Risk

The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk has been minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. In 2011 the BCUC determined that commodity hedging in the current environment was not a cost-effective means to meet the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011–2014 Price Risk Management Plan with the exception of certain elements to address regional price discrepancies. As a result, the FortisBC Energy companies have suspended all commodity hedging activities, with the exception of certain limited swaps as permitted by the BCUC. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

29. Financial Risk Management (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have been less out-of-the-money and, in the absence of rate regulation, other comprehensive income would have increased by $59 million for the year ended December 31, 2011 (2010 – $63 million). However, the FortisBC Energy companies defer any changes in the fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $59 million (December 31, 2010 – $63 million). Had the price of natural gas, with all other variables remaining constant, decreased by $1 per gigajoule, the fair value of the natural gas derivatives would have been further out-of-the-money and, in the absence of rate regulation, other comprehensive income would have decreased by $59 million for the year ended December 31, 2011 (2010 – $62 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $59 million (December 31, 2010 – $62 million).

The Corporation's exposure to market risk related to the foreign exchange forward contract and natural gas derivatives represents an estimate of possible changes in fair value that would occur assuming hypothetical movements in foreign exchange rates and commodity prices. The estimates may not be indicative of actual results and do not represent the maximum possible fair value gains and losses that may occur.

30. Commitments

The Corporation's consolidated commitments in each of the next five years and thereafter, as at December 31, 2011, excluding repayments of long-term debt and capital lease obligations, which are separately disclosed in Note 13, are as follows:

(in millions)	Total	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Gas purchase contract obligations (1)	**$ 300**	$ 180	$ 74	$ 46	$ –	$ –	$ –
Power purchase obligations							
FortisBC Electric (2)	**2,430**	47	45	40	41	40	2,217
FortisOntario (3)	**413**	48	49	50	51	52	163
Maritime Electric (4)	**190**	50	38	40	47	1	14
Capital cost (5)	**461**	17	17	19	17	19	372
Operating lease obligations (6)	**152**	26	17	16	16	16	61
Waneta Partnership promissory note (7)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (8)	**64**	3	4	4	4	3	46
Defined benefit pension funding contributions (9)	**58**	26	25	3	1	1	2
Office lease – FortisBC Electric (10)	**17**	2	2	2	1	1	9
Other (11)	**7**	1	1	1	1	–	3
Total	**$ 4,164**	$ 400	$ 272	$ 221	$ 179	$ 133	$ 2,959

(1) Gas purchase contract obligations relate to various gas purchase contracts at the FortisBC Energy companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2011.

(2) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new

resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. Additionally, in November 2011 FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount expected to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount has not been included in the commitments table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

(3) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 gigawatt hours ("GWh") of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(4) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In November 2010 the Company signed a new five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The new contract includes fixed pricing for the entire five-year period and covers, among other things, replacement energy and capacity for Point Lepreau. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(5) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(6) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases. They also include the operating lease obligations, up to April 2012, associated with the electricity distribution assets of Port Colborne Hydro and $7 million for the exercised election under the operating lease agreement to purchase the remaining assets of Port Colborne Hydro in April 2012.

(7) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion.

(8) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

(9) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2011 – Newfoundland Power
December 31, 2012 – FortisBC Energy companies (covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (covering unionized employees)
December 31, 2013 – FortisBC Electric

(10) On September 29, 1993 FortisBC Electric began leasing an office building in Trail, British Columbia for a term of 30 years. The terms of the agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

30. Commitments (cont'd)

(11) Other contractual obligations include building operating leases, AROs and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The consolidated capital program of the Corporation, including capital spending at its non-regulated operations, is forecast to be approximately $1.3 billion for 2012 and $5.5 billion in total from 2012 through 2016, which has not been included in the commitments table above.

In prior years, FEVI received non-interest bearing repayable loans from the federal government and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates.

As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the commitments table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

31. Expropriated Assets

Belize Electricity

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet (Note 8).

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Exploits Partnership

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

32. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI has begun the appeal process associated with the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

33. Subsequent Event

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing ("the Acquisition"). CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the Acquisition, which is expected to occur in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

34. Comparative Figures

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes related to: (i) a $58 million decrease in cash from financing activities associated with the issuance of common shares and a corresponding decrease in cash used in financing activities associated with dividends paid on common shares; (ii) a $17 million increase in long-term regulatory assets and a corresponding decrease in utility capital assets associated with a change in presentation at the FortisBC Energy companies; and (iii) a $13 million increase in other income (expenses) net, offset by a $7 million decrease in revenue, a $6 million decrease in operating expenses and a $12 million increase in finance charges associated with a change in the presentation of other income (expenses), net on the consolidated statement of earnings.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2011**	2010 [(1)]	2009 [(1)]
Revenue, including equity income	**3,747**	3,657	3,641
Energy supply costs and operating expenses	**2,562**	2,508	2,577
Amortization	**419**	410	364
Other income (expenses), net	**40**	13	10
Finance charges	**370**	362	369
Corporate taxes	**80**	67	49
Results of discontinued operations, gains on sales and other unusual items	**–**	–	–
Net earnings	**356**	323	292
Net earnings attributable to non-controlling interests	**9**	10	12
Net earnings attributable to preference equity shareholders	**29**	28	18
Net earnings attributable to common equity shareholders	**318**	285	262
Balance Sheets *(in $ millions)*			
Current assets	**1,120**	1,204	1,124
Goodwill	**1,557**	1,553	1,560
Other long-term assets	**1,263**	1,083	917
Utility capital assets, income producing properties and intangible assets	**9,622**	9,069	8,538
Total assets	**13,562**	12,909	12,139
Current liabilities	**1,320**	1,517	1,592
Other long-term liabilities	**1,566**	1,404	1,288
Long-term debt and capital lease obligations (excluding current portion)	**5,679**	5,609	5,276
Preference shares (classified as debt)	**320**	320	320
Total liabilities	**8,885**	8,850	8,476
Shareholders' equity	**4,677**	4,059	3,663
Cash Flows *(in $ millions)*			
Operating activities	**904**	732	681
Investing activities	**1,125**	991	1,045
Financing activities	**390**	455	563
Dividends, excluding dividends on preference shares classified as debt	**189**	172	176
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.86**	8.79	8.41
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease obligations (net of cash)	**55.0**	58.4	60.2
Preference shares (classified as debt and equity)	**8.6**	9.0	6.9
Common shareholders' equity	**36.4**	32.6	32.9
Interest Coverage *(x)*			
Debt	**2.1**	2.0	1.9
All fixed charges	**2.0**	1.9	1.8
Total Gross Capital Expenditures *(in $ millions)*	**1,174**	1,073	1,024
Common Share Data			
Book value per share (year end) *($)*	**20.53**	18.92	18.61
Average common shares outstanding *(in millions)*	**181.6**	172.9	170.2
Basic earnings per common share *($)*	**1.75**	1.65	1.54
Dividends declared per common share *($)*	**1.170**	1.410	0.780
Dividends paid per common share *($)*	**1.160**	1.120	1.040
Dividend payout ratio *(%)*	**66.3**	67.9	67.5
Price earnings ratio *(x)*	**19.1**	20.6	18.6
Share Trading Summary			
High price *($)* (TSX)	**35.45**	34.54	29.24
Low price *($)* (TSX)	**28.24**	21.60	21.52
Closing price *($)* (TSX)	**33.37**	33.98	28.68
Volume *(in thousands)* (TSX)	**126,341**	120,855	121,162

[(1)] Certain 2010 and 2009 comparative figures have been reclassified to comply with current period classifications, including the reporting of other income (expenses), net separately on the statement of earnings. Figures prior to 2009 have not been restated. Refer to Note 34 of the 2011 Annual Consolidated Financial Statements for further details.

[(2)] As at December 31, 2006, the regulatory provision for asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric due to a change in presentation adopted by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2008	2007	2006 (2)	2005 (2)	2004	2003	2002
3,907	2,718	1,472	1,441	1,146	843	715
2,859	1,904	939	926	766	579	477
348	273	178	158	114	62	65
–	–	–	–	–	–	–
363	299	168	154	122	86	74
65	36	32	70	47	38	32
–	8	2	10	–	–	–
272	214	157	143	97	78	67
13	15	8	6	6	4	4
14	6	2	–	–	–	–
245	193	147	137	91	74	63
1,150	1,038	405	299	293	191	180
1,575	1,544	661	512	514	65	60
487	424	331	471	418	345	241
7,954	7,276	4,049	3,315	2,713	1,563	1,459
11,166	10,282	5,446	4,597	3,938	2,164	1,940
1,697	1,804	558	412	538	296	334
727	697	482	477	138	62	39
4,884	4,623	2,558	2,136	1,905	1,031	941
320	320	320	320	320	123	–
7,628	7,444	3,918	3,345	2,901	1,512	1,314
3,538	2,838	1,528	1,252	1,037	652	626
661	373	263	304	272	157	134
852	2,033	634	467	1,026	308	349
387	1,826	456	224	777	232	261
191	146	77	64	51	38	35
8.70	10.00	11.87	12.40	11.28	12.30	12.23
59.5	64.3	61.1	58.7	61.4	60.0	65.2
7.3	5.2	10.0	8.6	9.4	6.7	–
33.2	30.5	28.9	32.7	29.2	33.3	34.8
1.9	1.9	2.2	2.5	2.3	2.2	2.3
1.8	1.7	2.0	2.1	2.0	2.1	2.2
935	803	500	446	279	208	229
17.97	16.69	12.19	11.74	10.45	8.82	8.50
157.4	137.6	103.6	101.8	84.7	69.3	65.1
1.56	1.40	1.42	1.35	1.07	1.06	0.97
1.010	0.880	0.700	0.605	0.548	0.525	0.498
1.000	0.820	0.670	0.588	0.540	0.520	0.485
64.1	58.6	47.2	43.7	50.3	48.9	49.9
15.8	20.7	21.0	18.0	16.2	13.9	13.5
29.94	30.00	30.00	25.64	17.75	15.24	13.28
20.70	24.50	20.36	17.00	14.23	11.63	10.76
24.59	28.99	29.77	24.27	17.38	14.73	13.13
132,108	100,920	60,094	37,706	29,254	31,180	21,676

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 17, 2012	August 17, 2012
November 16, 2012	February 14, 2013

Dividend Payment Dates

June 1, 2012	September 1, 2012
December 1, 2012	March 1, 2013

Earnings Release Dates

May 2, 2012	July 31, 2012
November 1, 2012	February 7, 2013

* *The declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Friday, May 4, 2012
10:30 a.m.
Delta St. John's
120 New Gower Street
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) to Common Shareholders as a convenient method of increasing their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

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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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St. John's, Newfoundland and Labrador

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Moncton, New Brunswick

Roy P. Rideout ✴ ★
Corporate Director
Halifax, Nova Scotia

✳ Audit Committee
✴ Human Resources Committee
★ Governance and Nominating Committee

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