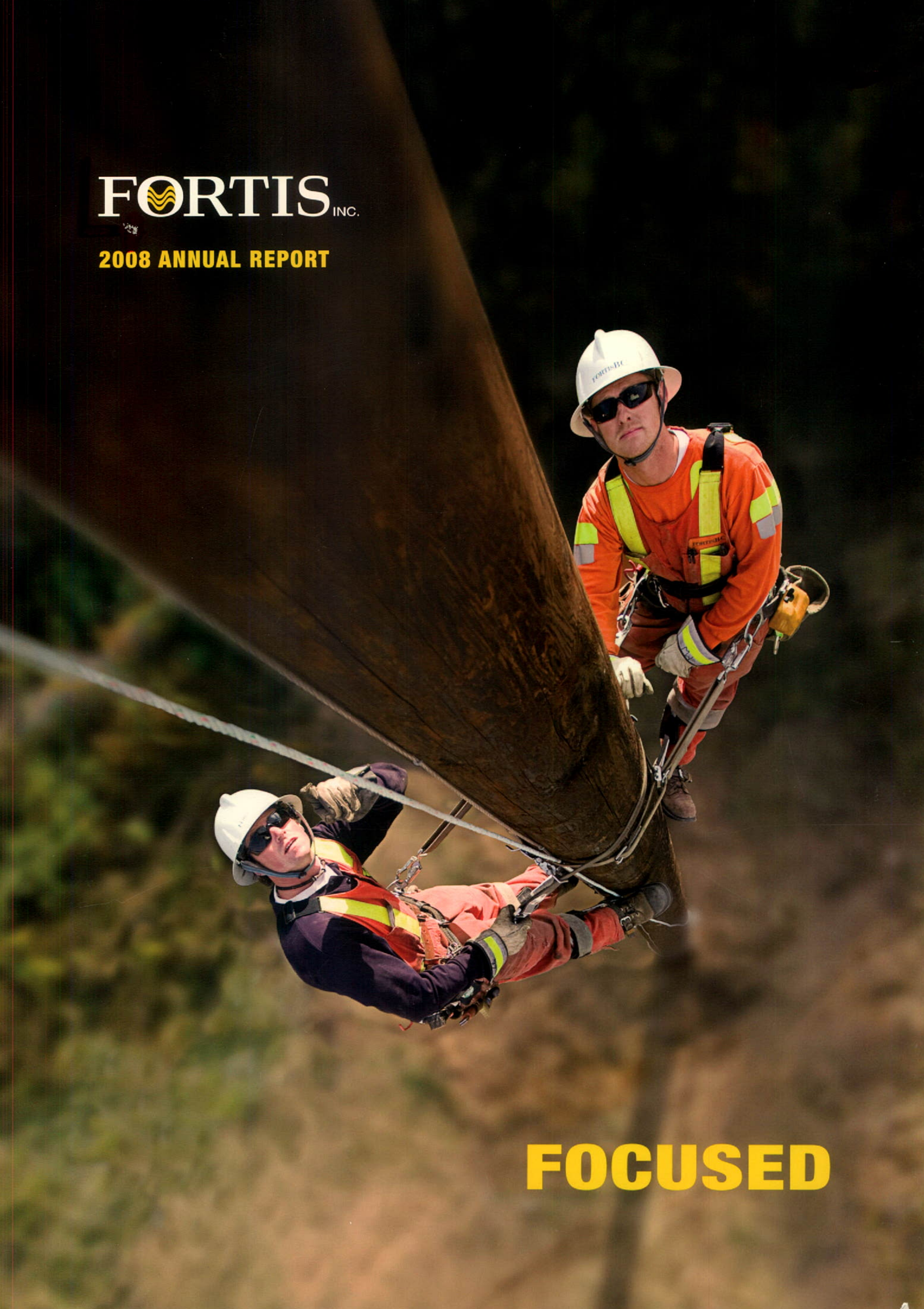
FORTIS INC.

2008 ANNUAL REPORT

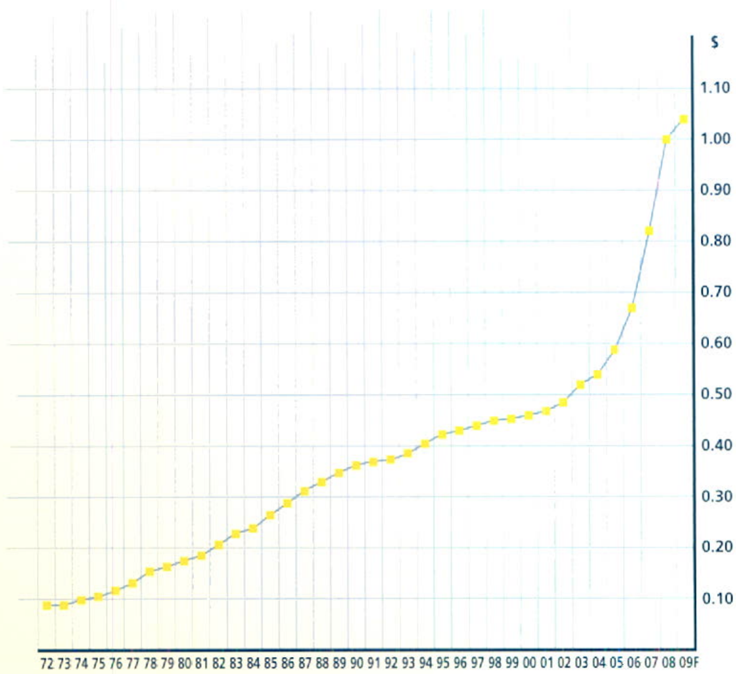


FOCUSED

Fortis Inc. is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers.

Contents

Dividends paid per common share

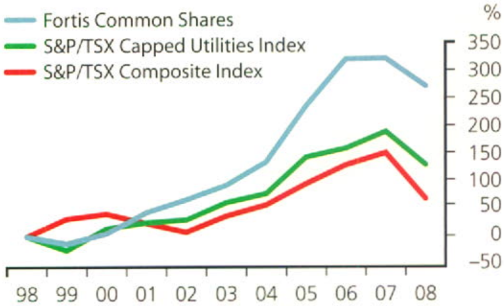


Fortis has increased its annual dividend to common shareholders for 36 consecutive years, the longest record of any public corporation in Canada.

Front Cover Photo: FortisBC employees Matt Wilson (left) and Dan Karslake (right)
Photo taken by Cam Craig, Terasen Gas employee

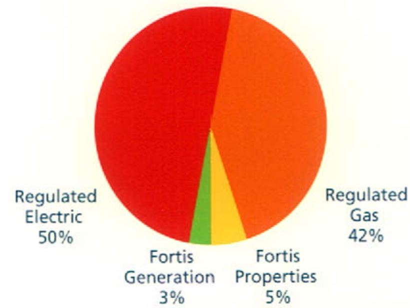
Back Cover Photo: Newfoundland Power Rattling Brook penstock
Photo taken by Gary Murray, Newfoundland Power employee

10-Year Cumulative Total Return

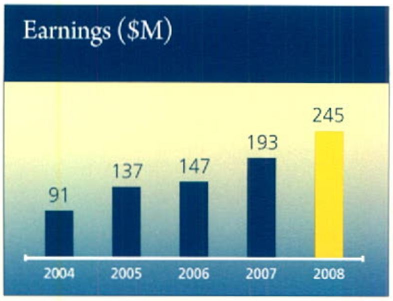


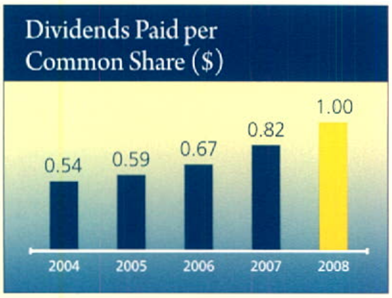
Total Assets Exceed $11 Billion

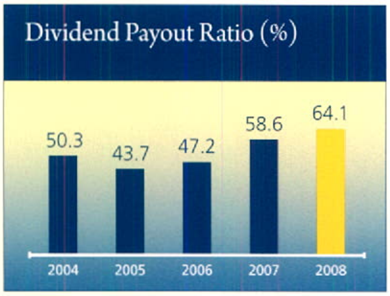
(as at December 31, 2008)

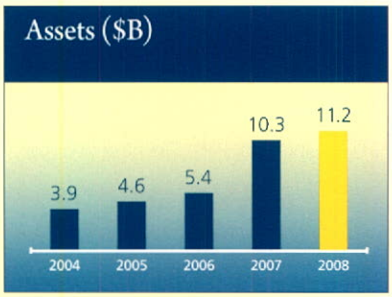


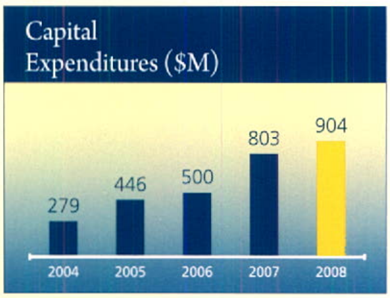
Investor Highlights

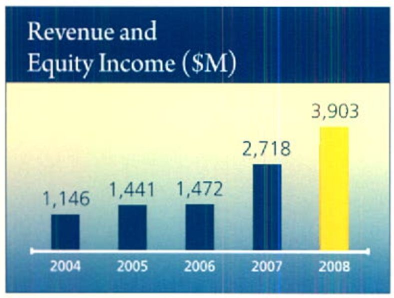


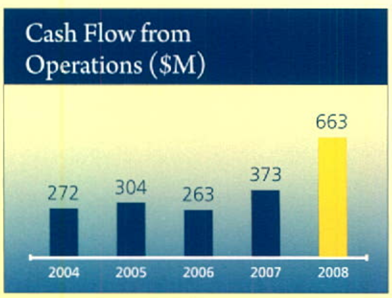


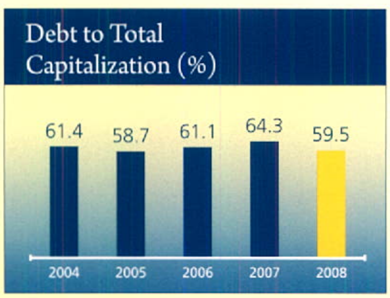


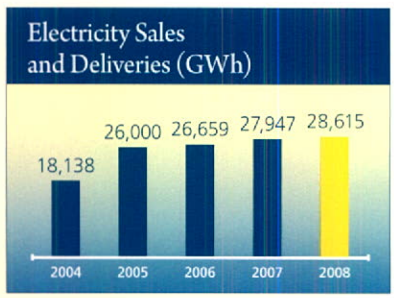












All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2008 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] 2008	Allowed ROE (%)[3] 2009
Total	931,000	1,260	1,402	221	220	4.6	3.1	118	8.62	8.47

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] 2008	Allowed ROE (%)[3] 2009
FortisAlberta	461,000	991	3,150	15,722	302	1.8	1.3	46	8.75	8.51[4]
FortisBC	157,000	545	746	3,087	117	1.2	0.9	34	9.02	8.87
Newfoundland Power	236,000	551	1,181	5,208	67	1.0	0.8	32	8.95	8.95
Maritime Electric	73,000	179	223	1,035	35	0.4	0.3	11	10.00	9.75
FortisOntario	52,000	125	227	1,147	11	0.2	0.1	3	9.00	8.39
Belize Electricity[5]	74,000	278	74	407	22	0.2	0.2	(4)	10.00[6]	10.00[6][7]
Caribbean Utilities[8]	24,000	197	94	635	44	0.6	0.4	13	9.00–11.00[6]	9.00–11.00[6]
Fortis Turks and Caicos	9,000	95	29	157	44	0.2	0.2	8	17.50[6][9]	17.50[6]
Total	1,086,000	2,961	5,724	27,398	642	5.6	4.2	143		

(1) Terasen primarily 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 2009
(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.
(4) Interim ROE pending outcome of regulatory proceeding
(5) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to the consolidated earnings of Fortis, based on the Corporation's 70.1% ownership interest.
(6) Regulated rate of return on rate base assets ("ROA")
(7) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application
(8) Fortis holds a 57% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations as at and for the 14 months ended December 31, 2008 due to a change in the utility's fiscal year end. Earnings represent Caribbean Utilities' contribution to the Corporation's consolidated earnings for the 14 months ended December 31, 2008.
(9) Significant investment is currently occurring at the utility. 2008 achieved ROA was lower than the ROA allowed under the licence.

Non-Regulated

Fortis Generation[1]

	Generating Capacity (MW)	Energy Sales (GWh)	Assets[3] ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	195	1,217	0.4	30	28

Fortis Properties[2]

	Employees (#)	Assets ($B)	Earnings[4] ($M)	Capital Program ($M)
Total	2,000	0.6	23	14

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State
(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 20 hotels across Canada
(3) Includes $126 million in "Other" non-regulated assets
(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2008

Information is for the fiscal year ended December 31, 2008 unless otherwise indicated.

Left – The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,402 TJ in 2008.

Right – Fortis electric utilities own and/or operate approximately 136,000 kilometres of transmission and distribution lines and met a combined peak demand of more than 5,700 MW in 2008.

Report to Shareholders

2008 has been another successful year for your company and marks the 9th consecutive year Fortis has delivered record earnings to shareholders.

Fortis achieved net earnings applicable to common shares of $245 million, 27 per cent higher than earnings of $193 million in 2007. Earnings per common share were $1.56, 16 cents higher than earnings per common share of $1.40 for the previous year.

Growth in earnings, excluding one-time items, was primarily attributable to a full year of earnings from Terasen and increased contributions from non-regulated hydroelectric generation. Earnings in 2008 were enhanced by a one-time $7.5 million tax reduction ($5.5 million at the Terasen Gas companies and $2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen but were reduced by a one-time $13 million charge that represented the Corporation's share of fuel and purchased power costs disallowed by Belize Electricity's regulator.

Dividends paid per common share grew to $1.00 in 2008, 22 per cent higher than 82 cents paid per common share in the previous year. The dividend payout ratio was approximately 64 per cent in 2008. Fortis increased its quarterly common share dividend to 26 cents, commencing with the first quarter dividend paid in 2009. The 4 per cent increase in the quarterly common share dividend translates into an annualized dividend of $1.04 and extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

In December, Fortis amended and restated its Dividend Reinvestment and Share Purchase Plan to provide shareholders with a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends. The discount became effective with dividends paid on March 1, 2009.

Over the past five years, Fortis delivered an average annualized total return of 14.3 per cent, the highest in its sector, and outperformed both the S&P/TSX Capped Utilities Index and S&P/TSX Composite Index, which delivered average annualized total returns of 7.3 per cent and 4.2 per cent, respectively, over that period.

In October 2008, Fortis was placed in the S&P/TSX 60, 60 Capped and Equity 60 indices. The average daily trading volume for the 46 trading days in 2008 that Fortis was a member of these indices was approximately 662,000 common shares, almost 35 per cent higher than the average daily trading volume for the year-to-date period prior to inclusion. Over the past five years, the average daily trading volume of Fortis common shares has increased 4.5 times, exceeding, on average, 525,000 common shares traded daily in 2008.

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. At the end of 2008, regulated rate base assets approached $7 billion; total assets of Fortis exceeded $11 billion, more than five times the amount five years ago. Growth has been driven by two large acquisitions: the $3.7 billion acquisition of Terasen in May 2007 and the $1.5 billion acquisition of FortisAlberta and FortisBC in May 2004. As well, growth has occurred organically through the continued investment in energy infrastructure. Over the past five years, Fortis utilities have invested approximately $2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.

Left – Fortis, through its regulated and non-regulated businesses, owns and/or operates more than 1,800 MW of generation, mainly hydroelectric.
Right – The regulated utilities of Fortis serve more than 2,000,000 customers in five Canadian provinces and three Caribbean countries.

Report to Shareholders

2008 marked the largest annual capital investment program in the history of Fortis. Consolidated capital expenditures, before customer contributions, were $904 million. Much of this investment was driven by the Terasen Gas companies, FortisAlberta, FortisBC and regulated and non-regulated electric utility operations in the Caribbean. Terasen Gas (Vancouver Island) started construction of its approximate $200 million liquefied natural gas storage facility, which will enhance reliability of supply to customers when it comes into service in late 2011. FortisAlberta continued work on its four-year Automated Meter Infrastructure Project, estimated at a total cost of $124 million, which will enable customers to better monitor and manage energy consumption. FortisBC received regulatory approval to proceed in 2009 with the $141 million Okanagan Transmission Reinforcement Project, the largest capital initiative ever to be undertaken by the utility. The project will provide needed system enhancements in the Okanagan region and help ensure the delivery of safe, reliable energy to customers. Construction continued on the US$53 million 19-megawatt ("MW") Vaca hydroelectric generating facility in Belize. When it comes online, expected at the beginning of 2010, the amount of energy Belize Electricity sources from hydroelectricity, the least-cost source of energy supply available, will increase to approximately 45 per cent.

The Terasen acquisition became accretive to earnings per common share of Fortis in the first quarter of 2008. The Terasen Gas companies contributed $118 million to earnings for the full year in 2008 compared to $50 million for the 7½ months of ownership in 2007. Results for 2008 were favourably impacted by an approximate $5.5 million tax reduction related to the settlement of historical corporate tax matters and a higher allowed rate of return on common shareholder's equity ("ROE") compared to 2007. Results for 2007 included a $7 million after-tax gain on the sale of surplus land.

Canadian Regulated Electric Utilities contributed earnings of $126 million compared to $125 million for 2007. Earnings grew $5 million year over year, excluding the impact of a one-time gain of $2 million in 2007 associated with an interconnection agreement-related refund at FortisOntario and the subsequent regulator-required repayment of the refund in 2008 by the utility. The key performance drivers were rate base growth and the higher allowed ROEs at FortisAlberta, FortisBC and Newfoundland Power, partially offset by lower corporate tax recoveries at FortisAlberta.

Customer rates for 2009 have been approved for the four largest utilities, which account for approximately 77 per cent of the total assets of Fortis. The allowed ROEs for 2009 at Terasen Gas Inc. and FortisBC declined slightly to 8.47 per cent and 8.87 per cent, respectively. The allowed ROE for 2009 at Newfoundland Power remains at 8.95 per cent. FortisAlberta is currently engaged in a generic cost of capital proceeding with its regulator and a decision on the utility's allowed ROE for 2009 is not expected until later in the year. In the interim, as directed by its regulator, customer rates for 2009 at FortisAlberta have been set using the utility's allowed ROE for 2007 of 8.51 per cent.

Caribbean Regulated Electric Utilities contributed earnings of $17 million compared to $31 million for 2007. Earnings were $3 million lower year over year, excluding the impact of a one-time loss of $13 million in 2008 related to a regulatory order received at Belize Electricity, which is being legally contested by the Company, and a one-time loss of $2 million in 2007 associated with the disposal of steam-turbine assets at Caribbean Utilities. Overall electricity sales growth and two additional months of earnings from Caribbean Utilities, associated with a change in the utility's fiscal year end, were more than offset by the impact of a 3.25 per cent reduction in base electricity rates at Caribbean Utilities, effective January 1, 2008; a lower allowed rate of return on rate base assets ("ROA") at Belize Electricity; and an approximate $2 million revenue loss at Fortis Turks and Caicos associated with Hurricane Ike.

Over the past five years, Fortis utilities have invested approximately $2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.

Report to Shareholders

Non-Regulated Fortis Generation contributed earnings of $30 million, $6 million higher than for 2007. Performance was driven by increased hydroelectric production in central Newfoundland, Belize and Upper New York State, as a result of higher rainfall, and higher average wholesale energy prices in Upper New York State and Ontario.

Commencing in May 2009, Fortis will no longer have the benefit of the 75-MW Rankine generating facility in Ontario due to the expiration of the water rights on the Niagara River. However, earnings' projections for Vaca, combined with the planned substantial consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings associated with the expiry of the Rankine water rights.

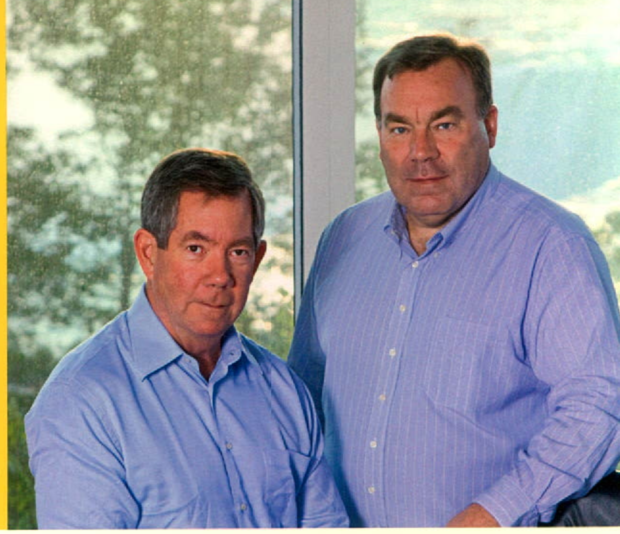
Fortis Properties delivered earnings of $23 million compared to $24 million for 2007. Excluding a $2 million favourable tax adjustment in 2007, earnings were $1 million higher year over year, mainly due to a full year of earnings from Delta Regina, which was acquired in August 2007.

Fortis continues to maintain strong investment-grade credit ratings, allowing it to have good access to the debt capital markets. Fortis is rated A– by Standard & Poor's and BBB(high) by DBRS. Its four largest utilities all have strong investment-grade credit ratings.

Fortis and its subsidiaries raised almost $1.2 billion in the capital markets in 2008. In December, the Corporation completed a $300 million common share issue, the net proceeds of which 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. In the second quarter of 2008, Fortis issued preference shares for gross proceeds of $230 million, the net proceeds of which were mainly used to repay $170 million borrowed under the Corporation's committed credit facility and to fund subsidiary equity requirements. Canadian Regulated Utilities issued $660 million of 30-year long-term debt at rates ranging from 5.80 per cent to 6.05 per cent. The proceeds provide long-term funding for capital programs to enhance reliability of gas and electricity service and meet customer growth.

At December 31, 2008, Fortis had consolidated credit facilities of $2.2 billion, of which $1.5 billion was unused. Approximately $2 billion of the total credit facilities are committed facilities, the majority of which have maturities ranging from 2011 to 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. The Corporation's long-term debt maturities and repayments are expected to average approximately $180 million annually over the next five years. With its substantial credit facilities and conservative capital structure, we believe Fortis has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009.

Employee success underpins corporate success. To each of our more than 6,200 employees, thank you for your commitment to customers. We extend our appreciation to the Board of Directors of Fortis for your governance and counsel. We also offer our gratitude and best wishes to Dr. Linda Inkpen who retires from the Board in 2009.



Left – The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts following Hurricane Ike, a Category 4 hurricane.

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

Report to Shareholders

Fortis is focused on executing its 2009 consolidated capital program, estimated at approximately $1 billion, to meet customers' expectations and growth in energy demand. Over the next five years, the consolidated capital expenditure program is expected to be approximately $4.5 billion, substantially all of which will be funded at the subsidiary level. This capital investment, which will mainly occur in western Canada, will add value for customers and shareholders and fortify the position of Fortis as a leading owner of energy infrastructure in Canada.

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.

Left – Officers of Terasen (back row l-r): Douglas Stout, VP, Marketing and Business Development; Dwain Bell, VP, Distribution; Robert Samels, VP, Business Services and CIO; Cynthia Des Brisay, VP, Gas Supply and Transmission; Roger Dall'Antonia, VP, Corporate Development and Treasurer; (front row l-r): Scott Thomson, VP, Regulatory Affairs and CFO; Jan Marston, VP, HR and Operations Governance; Randall Jespersen, President and CEO; David Bennett, VP, Regulatory Affairs and General Counsel

Right – Terasen began construction on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008.

Terasen

Regulated Gas Operations

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving 931,400 customers in more than 125 communities 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 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 designs, owns and operates geothermal systems, community piping and energy-transfer systems to harness renewable energy sources.

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 834,000 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 95,000 customers. TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines. In 2008, gas volumes exceeded 221,000 terajoules ("TJ") and a peak day demand of 1,402 TJ was met.

Terasen achieved an all-time high Customer Satisfaction Rating of 79.7 per cent in 2008. The Company has improved its Customer Satisfaction Rating for each of the past five years.

Approximately $220 million, before customer contributions, was invested in capital programs in 2008 to ensure the safe, reliable delivery of piped energy to customers.

Construction started on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008. 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. It is expected to come into service by late 2011.

Construction continued on the 50-kilometre natural gas pipeline from Squamish to Whistler. The pipeline, a key component of the Sustainable Energy Plan of the Resort Municipality of Whistler, is expected to be completed in spring 2009, followed by the conversion of the community's propane system. The total cost of the pipeline and conversion is expected to be approximately $51 million.

Completed under budget and almost two months ahead of schedule, the $24 million Vancouver Low-Pressure Replacement Project concluded with the seismic upgrade of 95 kilometres of natural gas distribution pipelines and 7,100 service connections. In addition to ensuring the safety and integrity of the gas distribution system, the project enhances delivery service by accommodating modern high-efficiency appliances.

Left – The four-year Automated Meter Infrastructure ("AMI") Project, estimated at a total capital cost of $124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

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

FortisAlberta

Regulated Electric Operations

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 108,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 461,000 customers in 175 communities and met a peak demand of 3,150 MW in 2008.

FortisAlberta achieved a Customer Satisfaction Rating of 81 per cent in 2008, a marked improvement from its average annual rating for the past three years of 76 per cent.

A record $302 million, before customer contributions, was invested in capital assets in 2008, primarily to meet growth in customer demand. More than 12,000 new customers were connected to the utility's distribution system. The Company worked closely with the transmission service provider and the Alberta Electric System Operator to add substation capacity, improve reliability and meet customer load growth in Balzac, Tilley, Stavely, Bruderheim and Blackfalds.

The Automated Meter Infrastructure ("AMI") Project involved the installation of more than 70,000 electronic meters at customer sites in 2008. AMI technology, which replaces the manual meter reading system, will help reduce operating costs and enable customers to better monitor and manage their energy usage on a monthly basis. The four-year AMI Project, estimated at a total capital cost of $124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

Approximately $50 million was invested in projects to improve system reliability, customer service and safety. Projects included the replacement of more than 4,000 deteriorated poles, the installation of distribution automation equipment in Airdrie and St. Albert to enable fast restoration of service following an outage and the introduction of new technology that involves the injection of silicone to extend the service life of underground cables.

Construction was completed on the utility's $26 million 88,000-square foot operations and customer service facility in Airdrie. The new facility houses approximately 30 per cent of FortisAlberta's workforce, previously located in leased office space in Calgary. The Company earned the City of Airdrie's 2008 Eco Edge Award as a result of environmental leadership at the new facility, which features innovative environmental considerations including a 95,000-litre rainwater cistern and energy-efficient windows and lighting.

As a result of productivity improvements, FortisAlberta achieved an operating cost per customer of $209 compared to $216 in 2007. Better performance was achieved as a result of revised work practices to improve the time to complete projects and enhance work capacity. New conductor installation equipment helped improve field work practices, resulting in increased efficiency and higher quality of work. Efficiencies were also created through the utility's ability to assign resources, bundle work and reduce employee travel time.

The Company implemented an environmental management system consistent with the international ISO 14001 standard. The system and related training initiatives provide a new tool to manage environmental issues and improve operational performance.

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

Right – FortisBC invested approximately $117 million, before customer contributions, in capital projects in 2008 to meet growing energy demand and replace aging infrastructure.

FortisBC

Regulated Electric Operations

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution 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 about 1,591 gigawatt hours ("GWh"). FortisBC also manages 904 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 Company met a record peak demand of 746 MW in 2008, exceeding the previous record of 718 MW reached in 2006.

FortisBC achieved a Customer Satisfaction Rating of 86 per cent in 2008, consistent with its rating in 2007.

An intense wind storm swept through the utility's service territory in July, causing power outages to approximately 25,000 customers. More than 150 employees, including power-line technicians, call centre and system control centre personnel and meter readers, were involved in safely restoring power to the majority of customers within 24 hours. Call centre personnel fielded more than 5,000 calls during one storm day, ten times the normal daily call volume.

FortisBC is focused on providing the highest level of customer service and ensuring the timely and cost-efficient installation of new service connections. In 2008, 454 residential extension quotes were processed and 1,664 new service installations were completed. Electronic billing (eBills) was introduced, with more than 6,400 customers choosing to receive their electricity bills this way.

In 2008, approximately $117 million, before customer contributions, was invested in capital projects to meet growing energy demand and replace aging infrastructure. Construction was completed on the $6.2 million Ootischenia substation, creating an additional source of power supply to the Castlegar area in the West Kootenays. The new substation at Big White ski area, the final phase of the $20.5 million Big White Project, was commissioned and the $27 million Kettle Valley Substation Project in Rock Creek was energized. Work began on the $14.4 million Black Mountain substation and associated distribution line, servicing growth to areas northeast of Kelowna. The first phase of the $17.2 million Ellison Substation Project in Kelowna began with the upgrading of six kilometres of distribution and transmission lines.

Approximately $11 million was invested in the utility's ongoing hydroelectric generation Upgrade and Life-Extension Program. The program, which involves rebuilding 11 of the 15 hydroelectric generating units in the Company's four generating stations, is expected to be completed in 2012. The program will improve efficiency, safety and environmental stewardship and maintain the overall reliability of the plants.

Regulatory approval was received in 2008 for the $141 million Okanagan Transmission Reinforcement Project, the largest capital project to be undertaken by FortisBC. The project entails upgrades to the utility's existing transmission lines and substations and the building of a new 230-kilovolt ("kV") transmission line and substation. It will provide needed system enhancements in the Okanagan area, ensuring customers have safe and reliable energy as residential and business growth continues in the region. Construction is scheduled to commence spring 2009 with completion in mid-2011.

Left – Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008.

Right – Officers of Newfoundland Power (l-r): Jocelyn Perry, VP, Finance and CFO; Gary Smith; VP, Engineering and Operations; Earl Ludlow, President and CEO; Lisa Hutchens, VP, Customer Relations and Corporate Services; Peter Alteen, VP, Regulatory Affairs and General Counsel

Newfoundland Power

Regulated Electric Operations

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 236,000 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 1,181 MW in 2008. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

Despite the impact to customers of rising energy prices, Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008, slightly higher than the rating achieved in the previous year. Strategic capital investments and employee commitment to customer service enabled electricity to be delivered to customers 99.97 per cent of the time in 2008.

Approximately $67 million, before customer contributions, was invested in capital projects to help strengthen the electricity system, including $18.3 million to provide service to new customers. The Company invested $1.5 million and worked jointly with Newfoundland Hydro and two independent developers to connect 54 MW of renewable wind energy to the island's electricity system. To further enhance system reliability, Newfoundland Power completed a $3.4 million upgrade of the transmission lines on the Bonavista Peninsula and Southern Shore of the Avalon Peninsula and refurbished several of its substations across the island at a total cost of $2.4 million. Performance optimization of 43 distribution feeders in high-growth areas was undertaken to prevent power outages and the use of handheld computers was increased to streamline maintenance workflow.

The Company partnered with Newfoundland Hydro to provide customers with the information, tools and programs they need to be energy efficient. The two utilities completed a Five-Year Energy-Conservation Plan with the goal of conserving an estimated 70 GWh of energy annually through 2013, scheduled to begin in 2009. Newfoundland Power became an active partner in the Energy Conservation and Efficiency Partnership under the Government of Newfoundland and Labrador's Energy Plan, coordinating and assisting with energy conservation and efficiency initiatives.

Online connection with customers improved throughout the year. Customer visits to the corporate website increased 20 per cent over the previous year.

Newfoundland Power completed its first year under the internationally recognized OHSAS 18001 Health and Safety Management System standard. Safety education, training and awareness initiatives included comprehensive employee programs dealing with hazard assessment through risk management/job planning, high-voltage electricity switching and safe work practices around de-energized equipment. The Company launched a new contractor website, which provides easy online access to safety training requirements, practices and policies. Electrical safety presentations were delivered to more than 2,600 children in 53 schools throughout the province. Newfoundland Power delivered safety training to 190 firefighters across the island and training was provided to members of the Canadian military in preparation for their power-restoration efforts in Afghanistan.

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

Right – Maritime Electric serves approximately 73,000 customers, or 90 per cent of electricity consumers, on Prince Edward Island.

Maritime Electric

Regulated Electric Operations

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI" or the "Island"), serves approximately 73,000 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 at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. 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 223 MW in 2008.

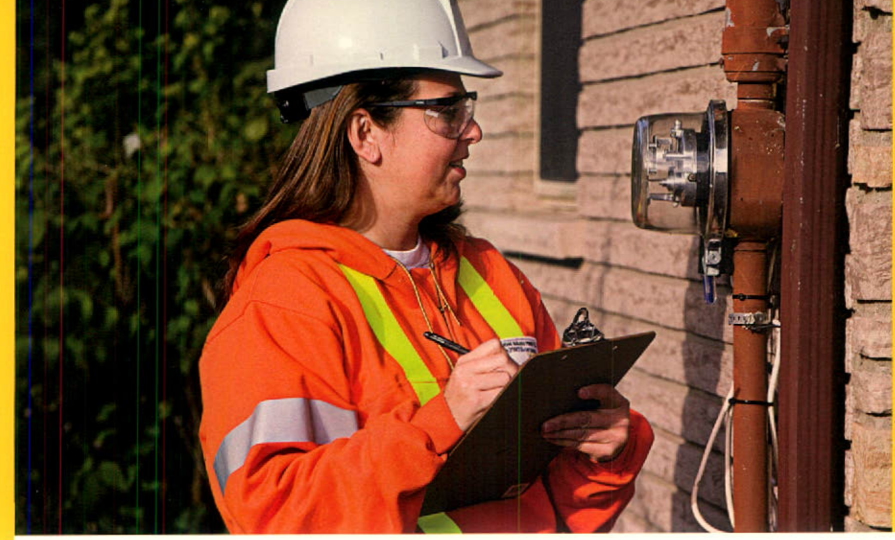
Maritime Electric purchases approximately 87 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these stations.

In April 2008, a refurbishment began on the Point Lepreau Generating Station that will extend its life by 25 years and provide additional stability with respect to long-term energy supply. 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 13 per cent of total energy supply was derived from wind-powered generation in 2008.

The Government of Prince Edward Island requires Maritime Electric to have a total of 30 per cent of its annual energy sales sourced from on-Island wind farms by 2013. The Company is working with the Government of Prince Edward Island and PEI Energy Corporation on the development of additional wind-powered generation. It is expected that a request for proposal for the additional wind-powered energy expansion will be issued by the provincial government by mid-2009.

Approximately $35 million, before customer contributions, was invested in capital projects to improve system reliability and customer service. Construction continued on the $14 million 138-kV transmission line and power corridor in western PEI. The 71-kilometre transmission line will deliver wind-powered energy from current and future commercial operations in western PEI to the North American grid. The power corridor, which will be jointly funded by the Government of Prince Edward Island and SUEZ Energy North America, will facilitate further expansion of wind-powered generation.

Despite the impact of high world fossil fuel prices on the cost of energy purchased to meet the Island's energy demand, Maritime Electric achieved a Customer Satisfaction Rating of 80 per cent in 2008 compared to 73 per cent for the previous year. Several customer service initiatives were completed in 2008, including an upgrade of the Company's website. A number of new and improved website features were added, such as the Energy Calculator, which will assist customers in better understanding and managing their electricity consumption.



Left – By mid-2009, FortisOntario is scheduled to begin the installation of smart meters, which track time-of-use consumption data.

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

FortisOntario

Regulated Electric Operations

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power and Cornwall Electric and serves approximately 52,000 customers, mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario. Its regulated assets include approximately 1,570 kilometres of distribution and transmission lines in the Niagara and Cornwall regions, including an international interconnection between New York State and Fort Erie. FortisOntario owns a 10 per cent interest in Westario Power Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies that together serve more than 27,000 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. FortisOntario met a combined peak demand of 227 MW in 2008.

In October 2008, the Company entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc., which serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

The Company achieved an overall Customer Satisfaction Rating of 84 per cent in 2008, slightly higher than its rating for the previous year. Customers continue to rate the utility's reliability/safe delivery of electricity and quality of service at 91 per cent and 88 per cent, respectively.

FortisOntario again exceeded performance standards set by the OEB with respect to response times, service connections and call answer statistics. OEB standards will be expanded in 2009 and the Company will ensure all reporting requirements are met.

FortisOntario undertook two electricity conservation and demand management programs during the year. Almost 700 customers enrolled in the Summer Sweepstakes Program, which encouraged customers to reduce their electricity consumption by 10 per cent in July and August.

The Company invested $11 million, before customer contributions, in capital projects involving new service connections and rebuild projects designed to improve the safety and reliability of its distribution systems. In Port Colborne, construction began on a new $1.5 million substation that will support load growth and replace an existing substation near the end of its useful life.

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 2008, FortisOntario selected a supplier of smart meters and installation of this new technology is scheduled to begin by mid-2009. Approximately 27,000 of the utility's metered customers will move to time-of-use rates by the end of 2010.

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

Right – Belize Electricity earned a record Customer Satisfaction Rating of 86 per cent in 2008.

Belize Electricity

Regulated Electric Operations

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 74,000 customers, the utility met a peak demand of 74 MW in 2008 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), Hydro Maya Limited and its own diesel-fired 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 approximately 2,840 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

The ability of Belize Electricity to meet the energy needs of its customers was significantly challenged by regulatory decisions received in 2008. During the year, the Company was forced to delay several planned initiatives aimed at system expansion and improvement as a result of a US$12.5 million limit on capital expenditures imposed by the Public Utilities Commission of Belize.

While regulatory approval was granted in the latter part of the year to complete rural electrification projects and build interconnection facilities to connect with new generation sources, cash flow challenges continued to restrict Belize Electricity's ability to proceed with these projects and other key capital works. Revisions were made to various project schedules to reflect the capital work suspensions, including the construction of substations to connect with independent power producers, now scheduled for completion in the second quarter in 2009.

The Company invested approximately $22 million, before customer contributions, in capital expenditures in 2008. Projects completed during the year included the connection of several rural communities in the Belize and Cayo Districts to the national grid and the construction of an alternate feeder to serve the popular tourist destination of Placencia Village in Southern Belize. The new feeder will address Placencia's load growth, provide an alternate distribution line to the service area and enable service upgrades with fewer interruptions. A US$2 million mobile substation was also procured to maintain service while substation repairs and maintenance are being carried out.

The Company signed a revised Power Purchase Agreement ("PPA") with CFE during the year. Under the revised contract, Belize Electricity has the option to purchase up to 50 MW of energy at a firm rate with the option to purchase the 50 MW of energy at an economic rate if available and less expensive. The utility also signed a PPA with Belize Aquaculture Limited for the supply of approximately 15 MW of power sourced from a heavy fuel oil-fired generating facility in Southern Belize. Connection to the utility's electricity system, which is expected to occur in the second quarter of 2009, will enable the facility to provide backup power to improve system reliability. It will also reduce reliance on Belize Electricity's diesel generators, which are more costly to operate.

Despite the significant operational constraints imposed as a result of the regulatory decisions received, the Company earned a record Customer Satisfaction Rating of 86 per cent in 2008. Several improvement initiatives focused on enhancing service delivery. Operational regions were defined and a service-order management team was established to ensure customer requests are met expeditiously. As well, several new line vehicles were purchased and deployed to various load centres as necessary.

Left – Caribbean Utilities' electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

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

Caribbean Utilities

Regulated Electric Operations

Caribbean Utilities generates, transmits and distributes electricity to more than 24,000 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 137 MW and the Company met a record peak demand of 94 MW in 2008.

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 57 per cent controlling ownership interest in the utility.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region. A Customer Satisfaction Rating of 90 per cent was achieved in 2008 compared to 84 per cent in 2007. For the six-month period ended October 31, 2008, an Average Service Availability Index of 99.9 per cent was posted, with customers experiencing, on average, a total of less than one hour of outages for that period.

The Company successfully completed a Class A Ordinary Share Rights Offering (the "Offering") and related stand-by agreement in August 2008. Under the Offering, Caribbean Utilities raised US$28.2 million, the proceeds of which are supporting the ongoing capital programs necessary to meet energy demand and sustain reliability in the existing generation, transmission and distribution infrastructure.

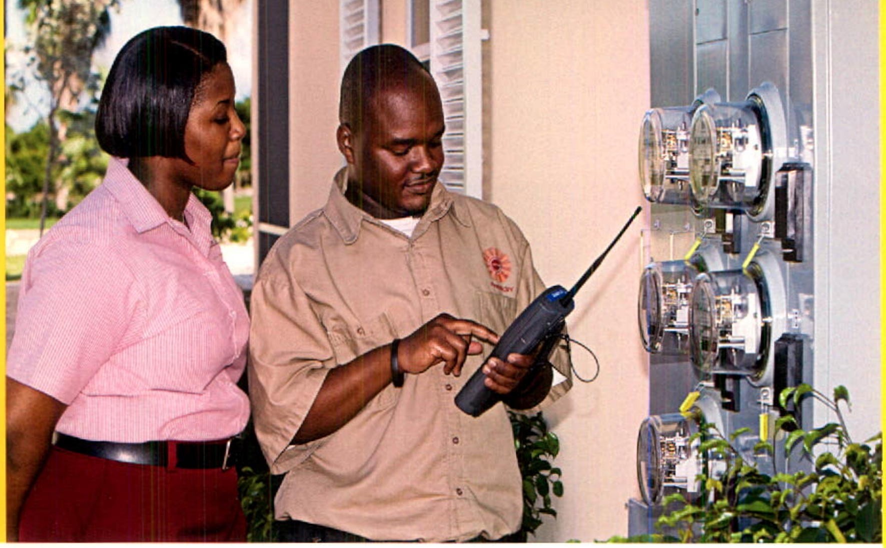
Capital investments totalled approximately $44 million in 2008. A significant project included ongoing work to complete the 69-kV distribution line from Rum Point to Old Man Bay. Under a strategic alliance relationship, Caribbean Utilities has contracted MAN Diesel SE to manufacture, install and commission an additional 16 MW of capacity, scheduled for completion in September 2009, which will bring total installed MAN Diesel SE supplied generation to approximately 66 MW.

The Company continues to offer its Energy Smart Program to promote energy conservation and has been conducting complementary Energy Smart audits for customers for six years. Caribbean Utilities also participated in the Chamber of Commerce Business Expo, a three-day event that showcased local businesses and attracted more than 3,000 visitors.

The Company continues to demonstrate its environmental commitment through its ISO 14001:2004 registered Environmental Management System associated with its generation operations. Employee-development initiatives continue to demonstrate the ongoing commitment to the "Investors in People" certification that Caribbean Utilities achieved in 2006. The utility awarded a scholarship for the Masters Program in Renewable Energy Development at Heriot-Watt University in Scotland.

As part of its initiative to enhance specialized employee skills to meet future energy demand, Caribbean Utilities is focused on the ongoing apprenticeship training of employees who work in areas such as operations, mechanical and electrical. The Company implemented a management development program accredited by the Institute of Leadership and Management, one of the main organizations for supervisory training in the United Kingdom, for all supervisory staff.

Caribbean Utilities launched an electrical safety education program for schools on Grand Cayman. The program uses a model city to demonstrate electrical hazards associated with transmission and distribution systems as well as residential electricity use.



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

Right – Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands.

Fortis Turks and Caicos

Regulated Electric Operations

Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands. The Company owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. Fortis Turks and Caicos also owns and operates an independent generating station and transmission and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. In May, the Company began supplying electricity to Dellis Cay. Its regulated assets include 335 kilometres of transmission and distribution lines. The utility has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 29 MW in 2008.

While challenged by increasing energy prices and severe weather conditions, the Company achieved a Customer Satisfaction Rating of 75 per cent in 2008.

In early September 2008, the Turks and Caicos Islands were struck by Tropical Storm Hanna followed by Hurricane Ike, a Category 4 hurricane which caused major damage to the utility's transmission and distribution system on South Caicos, with lesser damage occurring on North Caicos and Middle Caicos. Providenciales, the Company's major service territory and home to 80 per cent of its customers, was spared a direct hit. Generation facilities sustained minimal impact as a result of the hurricane. The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts. By the end of October, electricity had been restored to all customers ready to receive service.

Capital expenditures of approximately $44 million, before customer contributions, in 2008 primarily reflected investment in generation, transmission and distribution infrastructure, information technology platforms and systems, as well as land purchases necessary to meet energy demand and improve customer service.

The 2008/09 Generation Expansion Project is on schedule and will increase the Company's generating capacity by approximately 7 MW with the commissioning of two Caterpillar 3612 series units in early 2009. Capital projects undertaken to improve transmission and distribution reliability included the completion of dedicated underground feeders to Beaches Resort, the Islands' largest hotel, and the Provo Water Plant; the installation of a second power transformer at Grace Bay substation; and the completion of a transmission loop to Grace Bay substation. As a result of these initiatives, Fortis Turks and Caicos experienced a marked reduction in feeder outages in 2008.

New service connections included a number of large customers, among them Seven Stars Resort, Niki Beach Resort and Beach Club Resort.

The Company continued to implement recommendations from its environmental impact evaluation study. An environmental officer designate was appointed and received environmental training from Fortis Group personnel. Fortis Turks and Caicos plans to implement an environmental management system in 2009 that will be consistent with the international ISO 14001 standard by 2012.

Left – Construction of the US$53 million 19-MW Vaca hydroelectric generating facility on the Macal River in Belize is scheduled for completion at the beginning of 2010.
Right – Fortis Generation has a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

Fortis Generation

Non-Regulated Operations

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 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production hit a record high of 192 GWh in 2008 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 November. Construction of the US$53 million 19-MW Vaca hydroelectric generating facility continued and is scheduled for completion at the beginning of 2010. Vaca, a run-of-river plant situated approximately five kilometres downstream from Mollejon, is the final phase of the three-part hydroelectric development plan for the Macal River. BECOL sells its entire output to Belize Electricity under a 50-year PPA. Belize Electricity has signed a 50-year PPA with BECOL for the purchase of energy generated by Vaca. When it comes online, Vaca is expected to increase the average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

In Ontario, non-regulated operations include 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls, which expires in April 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. With the exception of the cogeneration plant in Cornwall, the electricity produced from these facilities is sold in Ontario at market prices.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi-Consolidated's two hydroelectric generating plants in central Newfoundland. The Exploits Partnership achieved annual production of 177 GWh in 2008. In December 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of Abitibi-Consolidated'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 provincial government has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated in the province.

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 from these modern facilities is sold at the wholesale level through a series of renewable contracts.

Left – Officers of Fortis Properties (l-r): Terry Chaffey, VP, Real Estate; Nora Duke, President and CEO; Jamie Roberts, VP, Finance and CFO

Right – In November 2008, Fortis Properties acquired Hotel Newfoundland. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms.

Fortis Properties

Non-Regulated Operations

Fortis Properties owns and operates 20 hotels, offering more than 3,800 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

The Hospitality Division continued to demonstrate strong growth through property enhancement, expansion and acquisition. Revenue per available room increased for the 13th consecutive year, reaching $80.39, primarily due to a higher average daily room rate. In November 2008, Fortis Properties acquired Hotel Newfoundland for approximately $22 million. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms. Aligning with guest expectations for a high-quality service experience, this premier hotel was rebranded as Sheraton Hotel Newfoundland in early 2009. Over the next three years, an approximate $9 million capital investment will be made to upgrade the hotel.

A $14 million 70-room expansion of Holiday Inn Express Kelowna commenced in 2008, which includes the addition of an exclusive executive floor, business and family suites, more meeting space, an enhanced fitness facility and two indoor waterslides. A $0.7 million expansion of the Four Points by Sheraton Conference Centre in Halifax, Nova Scotia was completed during the year. The project utilized space in the Maritime Centre, enabling the hotel to attract larger groups and conventions while providing enhanced service for real estate tenants. The expanded facility includes 12,000 square feet of convention space, in-house audiovisual technology services and courtyard meeting space.

The Real Estate Division's stable performance is supported by long-term leases with quality tenants and strong tenant relations. The year-end occupancy rate was 96.8 per cent, outpacing the national rate of 93.3 per cent. Company buildings have virtually zero vacancy in a number of downtown markets, including St. John's and Halifax. Capital improvements to real estate assets included a $1.4 million investment at Brunswick Square for electrical equipment replacement and entrance renovations and upgrades.

Approximately $0.7 million was invested in technology solutions to improve productivity and provide optimal customer service. A new financial management system was installed and a multiphase project to install a new payroll system is ongoing.

The Hospitality Division continued to demonstrate quality customer service. The Delta St. John's Hotel and Conference Centre won *Hospitality Newfoundland and Labrador's Accommodation of the Year Award* for demonstrating dedication to quality service, commitment to the tourism industry and community contribution. For the 11th consecutive year, Holiday Inn Peterborough-Waterfront won the *Readers' Choice Award for Best Hotel in Peterborough* from the region's newspaper, *The Peterborough Examiner*.

Significant emphasis continued to be placed on ensuring compliance with health and safety regulations and raising awareness of health and safety practices. Safety audits were conducted at all properties in 2008.

Leadership development remains a priority as Fortis Properties continues to focus on the growth of high-potential employees through mentoring, professional development courses, special projects, temporary assignments, lateral moves and job promotion.

In 2008, almost $3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes.

Our Community

Fortis remains focused on making a difference in the communities where our employees work and live. In 2008, almost $3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes. Hundreds of employees throughout the Fortis Group of Companies were there to help.

Terasen sponsored the *2008 Environmental Mind Grind* organized by the Environmental Educators of the Central Okanagan Heroes. The event motivated 95 school teams and 450 students throughout British Columbia to display their environmental stewardship knowledge in a game show-style trivia contest.

FortisAlberta employees in Calgary, Red Deer and Edmonton raised $25,000 for the *CIBC Run for the Cure* in 2008. It was a record-setting year for participation by employees, who raised twice the amount collected in 2007.

FortisBC employees came together and raised almost $6,000 for the *Hour Kids Campaign*, a fundraiser to help complete upgrades to the maternity and pediatric departments at the Kootenay Boundary Regional Hospital.

Newfoundland Power employees were recognized with a national award at the 9th annual Canadian Blood Services *Honouring Our Lifeblood* event. Since joining the *Partners for Life* program in 2004, employees have made more than 1,400 blood donations.

Maritime Electric offered its *Electrical Safety Presentation* as part of the Grade Six science and math curriculum throughout the school system on Prince Edward Island.

FortisOntario donated $5,000 to the *Port Cares Reach Out Centre* in Port Colborne. The Centre offers a drop-in service and meal program, serving approximately 12,000 meals to the general public each year.

Belize Electricity awarded a three-year scholarship, valued at BZ$36,000 per annum, to a Belizean student to pursue a *Diploma in Engineering Technology* at the College of the North Atlantic in Newfoundland.

Caribbean Utilities enhanced its partnership with the *Central Caribbean Marine Institute*, an international non-profit organization that is extending its Coral Reef Awareness Program to schools across Grand Cayman through its Ocean Literacy education curriculum.

Fortis Turks and Caicos joined the campaign to redevelop the sport of cricket on the Turks and Caicos Islands by making a $4,000 donation and becoming the title sponsor of the *Provo Cricket Association's Men's League*.

Fortis Properties was the title sponsor of the *Business Community Anti-Poverty Initiative Annual Golf Tournament* in New Brunswick. Through its participation during the past six years, the Company has assisted in raising more than $240,000 in support of the Resource Centre for Youth in Saint John.

Management Discussion and Analysis

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

Dated March 11, 2009

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2008 Consolidated Financial Statements and Notes to the 2008 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2008 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 ("GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("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 timing of regulatory decisions; the electricity sales growth rate expected at the Corporation's regulated utilities in the Caribbean in 2009; consolidated forecasted gross capital expenditures for 2009 and in total over the next five years, as well as the expected significant capital projects in 2009 and their expected costs and time to complete; the expected impacts on Fortis of the downturn in the global economy; the expected increase in activities at Terasen Energy Services; no significant decrease in subsidiary operating cash flows is expected in 2009; the subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs; the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009; expected long-term debt maturities and repayments in 2009 and on average annually over the next five years; no material increase in interest expense and/or fees associated with renewed and extended credit facilities is expected in 2009; 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 2009; the estimated impact a decease 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 no material increase in defined benefit pension expense in 2009. 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 2009; 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; 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; an ultimate resolution of the Exploits River Hydro Partnership that differs from what is currently expected by management; 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; an unexpected outcome of legal proceedings currently against the Corporation; licences and permits; loss of service area; market energy sales prices; transition to International Financial Reporting Standards; changes in tax legislation; First Nations' lands; 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, 2008.

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 more than 2,000,000 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 real estate in Canada. In 2008, the Corporation's electricity distribution systems met a combined peak electricity demand of more than 5,700 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,402 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 reasonable rates, 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 traditional 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 real estate 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 195 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 for 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"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 834,000 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 95,000 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 propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 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 461,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers. 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 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant 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 approximately 236,000 customers. Newfoundland Power has an installed generating capacity of approximately 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 73,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 74,000 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 24,000 customers. The Company has an installed generating capacity of approximately 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' 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 on the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-fired generating capacity of 48 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 and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. 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 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033. For a further discussion of the Exploits Partnership and pending changes related to it refer to the "Liquidity and Capital Resources – Cash Flow Requirements" and "Critical Accounting Estimates – Contingencies" sections of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This 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 US 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 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate 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. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; 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. While currently not significant, 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	2008	2007	Variance *(%)*
Net Earnings Applicable to Common Shares *($ millions)*	**245**	193	26.9
Basic Earnings per Common Share *($)*	**1.56**	1.40	11.4
Diluted Earnings per Common Share *($)*	**1.52**	1.32	15.2
Weighted Average Number of Common Shares Outstanding *(millions)*	**157.4**	137.6	14.4
Revenue *($ millions)*	**3,903**	2,718	43.6
Dividends Paid per Common Share *($)*	**1.00**	0.82	22.0
Return on Average Common Shareholders' Equity *(%)*	**8.7**	10.0	(13.0)
Total Assets *($ millions)*	**11,178**	10,273	8.8
Cash Flow From Operating Activities *($ millions)*	**663**	373	77.7

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

On May 17, 2007, Fortis completed the acquisition of all of the issued and outstanding common shares of Terasen, formerly a wholly owned subsidiary of Kinder Morgan, Inc., for aggregate consideration of $3.7 billion, including the assumption of approximately $2.4 billion of consolidated debt. Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. The acquisition did not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

A significant portion of the net cash purchase price of Terasen was satisfied with the net proceeds of the public offering of Subscription Receipts completed by Fortis on March 15, 2007. Fortis issued approximately 44.3 million Subscription Receipts for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition on May 17, 2007, each Subscription Receipt was automatically exchanged, without payment of additional consideration, for one common share of Fortis. The remaining net cash purchase price was financed, on an interim basis, by drawing $125 million on the Corporation's existing credit facility.

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprised of the 274-room Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan, for an aggregate cash purchase price of approximately $50 million.

Key Trends and Risks: Terasen improved the risk profile of Fortis by providing the Corporation with a more economically diverse portfolio of assets and earnings. The expansion into natural gas added a new business segment, doubled the regulated rate base of Fortis and was complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The distribution franchises of the Terasen Gas companies have a well-diversified, mature, principally residential customer base and operate in a service territory that has experienced steady economic growth and includes substantially all of the service territory of FortisBC. The expansion into natural gas distribution provides Fortis with a platform for future growth in the regulated natural gas business in Canada and the United States.

A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than other regions of Canada. As at December 31, 2008, regulated utility assets comprised 92 per cent of total assets (December 31, 2007 – 92 per cent) and regulated utility assets in Canada comprised 82 per cent of total assets (December 31, 2007 – 84 per cent).

Declining long-term interest rates in Canada since 2005 have negatively impacted the formula-based allowed rate of return on common shareholders' equity ("ROE") used to set customer rates at each of the Corporation's four largest regulated utilities. The chart below highlights the trend in the regulator-allowed ROEs at each of the Corporation's four largest regulated utilities.

Regulator-Allowed ROE

(%)	2005	2006	2007	2008	2009
Terasen Gas Inc.	9.03	8.80	8.37	8.62	8.47
FortisAlberta	9.50	8.93	8.51	8.75	8.51[(1)]
FortisBC	9.43	9.20	8.77	9.02	8.87
Newfoundland Power	9.24	9.24	8.60	8.95	8.95

[(1)] Interim ROE pending outcome of regulatory proceeding

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

Economic growth in the province of Alberta has been robust in the past few years translating into strong customer, energy sales and rate base growth at FortisAlberta. The rate of growth may decrease in 2009 due to the current global economic environment and depressed world oil prices. FortisAlberta's service territory includes the environs of Calgary and Edmonton as well as the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC and the Terasen Gas companies over the past few years. Sales growth in 2008 at FortisBC was tempered due to decreased activity in the forestry sector. Organic earnings growth from the Corporation's regulated utilities in Canada 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 10 per cent at December 31, 2008 (December 31, 2007 – 8 per cent). The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher than that achieved 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 has been strong in the Corporation's service territories in the Caribbean, positively impacting customer and sales growth. The rate of growth is expected to be lower in 2009 due to the impact of the global economic downturn. 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 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 FortisAlberta and FortisBC for 2008 and 2009 electricity rates and at Newfoundland Power for 2008 electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of full-scale public hearing processes. Customer rates at Newfoundland Power and the Terasen Gas companies have also been set for 2009.

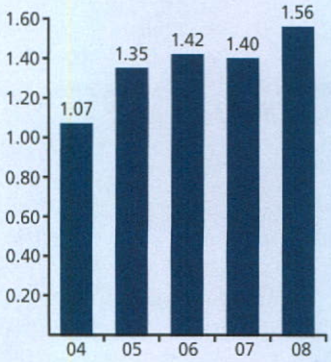
The Corporation's regulated gas and electric utilities require continual access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the subsidiary capital expenditure programs is mostly obtained at the regulated utility level. The subsidiaries issue debt mostly at terms ranging between 10 years and 30 years. As at December 31, 2008, approximately 84 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 $2.2 billion in credit facilities of which approximately $1.5 billion was available as at December 31, 2008. During 2008, Fortis and its subsidiaries issued almost $1.2 billion in equity and long-term debt. With strong credit ratings and conservative capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009.

Common share dividend payments increased to $1.00 per common share in 2008. Effective for the first quarter of 2009, a 4 per cent increase in the quarterly common share dividend to 26 cents from 25 cents extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

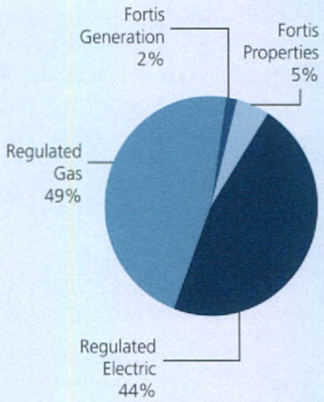
For a complete discussion of the Corporation's business risks, including regulatory risk and the impact on the Corporation and its subsidiaries of recent economic conditions, refer to the "Regulatory Highlights", "Business Risk Management" and "Outlook" sections of this MD&A.

Management Discussion and Analysis

Basic Earnings per Common Share *($)*

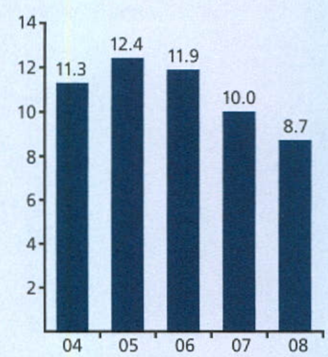


Revenue[1]
(year ended December 31, 2008)



[1] Excludes Corporate and Other

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



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $245 million in 2008, a 26.9 per cent increase over earnings of $193 million in the previous year. The increase in earnings was primarily due to earnings' contributions 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 tax recoveries at FortisAlberta. Results for 2008 also reflected a $7.5 million tax reduction ($5.5 million at the Terasen Gas companies and $2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen. Results for 2007 reflected a $7 million after-tax gain on the sale of surplus land at TGI.

Basic earnings per common share were $1.56 in 2008, an 11.4 per cent increase over $1.40 in the previous year. The increase was primarily due to growth in earnings associated with the Terasen Gas companies and increased non-regulated hydroelectric production. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and by the seasonality of earnings at the Terasen Gas companies.

Revenue: Revenue increased 43.6 per cent to approximately $3.9 billion from approximately $2.7 billion in 2007. The increase was driven by contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. The remainder of the increase was mainly the result of customer rate increases, which included the impact of higher allowed ROEs for 2008 and the flow through to customers of higher energy supply costs; two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end; and customer growth.

Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 8.7 per cent in 2008 compared to 10.0 per cent in 2007. The decline largely related to higher average common shareholders' equity associated with the May 2007 acquisition of Terasen.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $663 million in 2008, 77.7 per cent higher than $373 million in the previous year. The increase primarily reflected a full year of contributions from the Terasen Gas companies in 2008.

2008 Capital Expenditures: During 2008, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $904 million, including capital expenditures of approximately $220 million at the Terasen Gas companies. Total capital investment at FortisAlberta and FortisBC during 2008 was approximately $419 million, representing approximately 46 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 electricity systems.

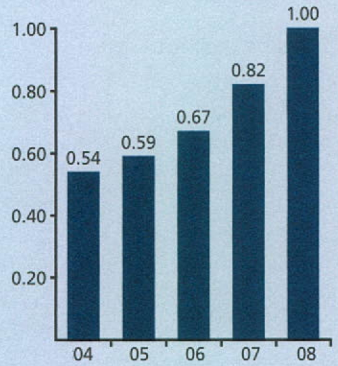
Dividends: Dividends paid per common share increased to $1.00 in 2008, up 22.0 per cent from 82 cents in 2007. Commencing with the first quarter dividend paid on March 1, 2009, Fortis increased its quarterly common share dividend 4 per cent to 26 cents from 25 cents. The Corporation's dividend payout ratio was 64.1 per cent in 2008 compared to 58.6 per cent in 2007.

In December 2008, the Corporation amended and restated its Dividend Reinvestment and Share Purchase Plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

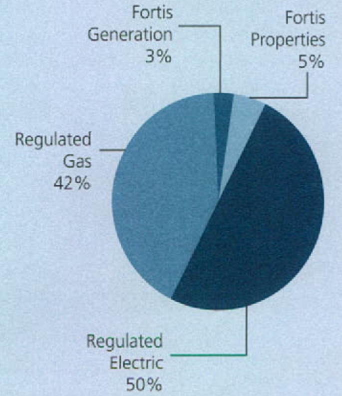
Asset Growth: Total assets increased 8.8 per cent to approximately $11.2 billion at the end of 2008 compared to approximately $10.3 billion at the end of 2007. The increase was primarily due to the Corporation's continued investment in energy systems at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets.

Financings: During 2008, Fortis and its utilities raised almost $1.2 billion of capital from a combination of preference share, common share and long-term debt issues. In the second quarter of 2008, the Corporation publicly issued 9.2 million 5.25% Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million under the Corporation's committed credit facility, fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. 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. At the subsidiary level, TGVI issued $250 million of 30-year 6.05% unsecured debentures in February; FortisAlberta issued $100 million of 30-year 5.85% unsecured debentures in April; Maritime Electric issued $60 million of 30-year 6.05% secured first mortgage bonds in April; and TGI issued $250 million of 30-year 5.80% unsecured debentures in May. Proceeds from the long-term debt issues at the utilities were primarily used to repay indebtedness under credit facilities incurred in support of capital spending. Additionally, partial proceeds from the issuance of the $250 million unsecured debentures by TGI were used to refinance $188 million of debt that matured in May 2008.

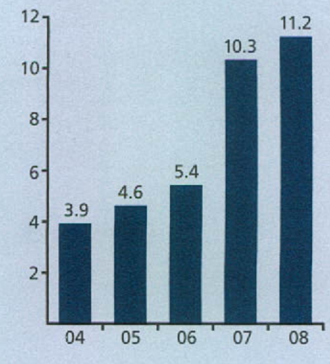
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2008)



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)*	2008	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies [1]	**118**	50	68
Regulated Electric Utilities – Canadian			
FortisAlberta	**46**	48	(2)
FortisBC	**34**	31	3
Newfoundland Power	**32**	30	2
Other Canadian	**14**	16	(2)
	126	125	1
Regulated Electric Utilities – Caribbean [2]	**17**	31	(14)
Non-Regulated – Fortis Generation	**30**	24	6
Non-Regulated – Fortis Properties [3]	**23**	24	(1)
Corporate and Other	**(69)**	(61)	(8)
Net Earnings Applicable to Common Shares	**245**	193	52

[1] Financial results are reported from May 17, 2007, the date of acquisition.

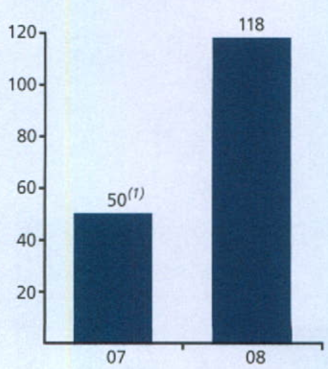
[2] Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

[3] Includes the results of the Fairmont Newfoundland hotel from November 2008, the date of acquisition

REGULATED UTILITIES

The Corporation's primary business is regulated utilities. In 2008, regulated earnings in Canada and the Caribbean represented approximately 83 per cent (2007 – 81 per cent) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 92 per cent of the Corporation's total assets as at December 31, 2008 (December 31, 2007 – 92 per cent).

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



[1] Earnings are from May 17, 2007

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2008 were $118 million (2007 – $50 million), which represented approximately 45 per cent of the Corporation's total regulated earnings (2007 – 24 per cent). Earnings for 2007 were from May 17, 2007, the date of acquisition of the Regulated Gas Utilities – Canadian. Regulated Gas Utilities – Canadian assets were approximately $4.6 billion as at December 31, 2008 (December 31, 2007 – $4.4 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 47 per cent).

Terasen Gas Companies

Financial Highlights

Years Ended December 31	2008	2007 [1]	Variance
Gas Volumes *(TJ)*	**221,122**	118,309	102,813
($ millions)			
Revenue	**1,902**	905	997
Energy Supply Costs	**1,268**	559	709
Operating Expenses	**253**	150	103
Amortization	**97**	58	39
Finance Charges	**129**	80	49
Gain on Sale of Property	**–**	(8)	8
Corporate Taxes	**37**	16	21
Earnings	**118**	50	68

[1] Results are reported from May 17, 2007, the date of acquisition.

Gas Volumes: Gas volumes were 221,122 TJ for 2008 compared to 220,977 TJ reported by the Terasen Gas companies for the full year in 2007. Increased sales volumes to residential customers, as a result of increased consumption due to cooler weather year over year, and higher sales volumes to customers under fixed price contracts, were largely offset by lower transportation volumes to customers sourcing their own gas supplies.

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 of natural gas only.

As a result of the operation of British Columbia Utilities Commission ("BCUC")-approved regulatory deferral mechanisms, changes in consumption levels and energy supply costs from those forecasted to set gas distribution rates do not materially affect earnings.

During 2008, net customer additions at TGI and TGVI totalled approximately 12,800, bringing the total customer count at TGI and TGVI to approximately 929,000 at December 31, 2008. During 2007, net customer additions at TGI and TGVI totalled approximately 13,900. Net customer additions in 2008 were lower than expected, reflecting weakening housing and construction markets and growth in multi-family housing where natural gas use is less prevalent compared to single-family housing.

Revenue: Revenue was approximately $1.9 billion for 2008 compared to $905 million for the partial year in 2007. In addition to the impact of revenue contribution for the full year in 2008, revenue also increased year over year due to: (i) the higher commodity cost of gas charged to customers; (ii) increased residential customer consumption; and (iii) an increase in gas distribution rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE for TGI and TGVI to 8.62 per cent and 9.32 per cent, respectively, from 8.37 per cent and 9.07 per cent, respectively.

Earnings: Earnings were $118 million for 2008 compared to $50 million for the partial year in 2007. Earnings for 2007 were favourably impacted by a $7 million after-tax gain on the sale of surplus land. Earnings for 2008 included an approximate $5.5 million tax reduction associated with the settlement of historical corporate tax matters. During the third quarter of 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency ("CRA") 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.

In addition to earnings' contribution for a full year in 2008 and the one-time tax reduction described above, earnings for 2008 were favourably impacted by the increase in gas distribution rates, effective January 1, 2008, reflecting a higher allowed ROE, partially offset by: (i) higher operating expenses driven by increased labour costs; (ii) higher amortization costs associated with the continued investment in capital assets; and (iii) higher finance charges reflective of higher borrowing rates.

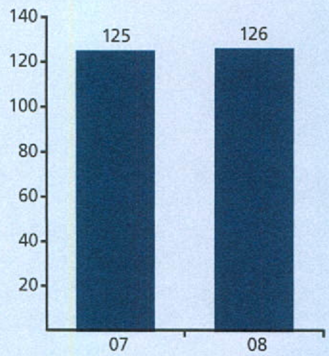
Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is used for space heating. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Outlook: TGI's allowed ROE for 2009 has been set at 8.47 per cent, down from 8.62 per cent in 2008. TGVI's allowed ROE for 2009 has been set at 9.17 per cent, down from 9.32 per cent in 2008. TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the regulator in the second quarter of 2009.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

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 the forecast gross capital expenditures for 2009 for the Terasen Gas companies is provided under the heading "Liquidity and Capital Resources – Capital Program".

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



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2008 were $126 million (2007 – $125 million), which represented approximately 48 per cent of the Corporation's total regulated earnings (2007 – 61 per cent). Regulated Electric Utilities – Canadian assets were approximately $4.6 billion as at December 31, 2008 (December 31, 2007 – $4.2 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 45 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31	2008	2007	Variance
Energy Deliveries *(GWh)*	**15,722**	15,378	344
($ millions)			
Revenue	**300**	270	30
Operating Expenses	**130**	122	8
Amortization	**85**	75	10
Finance Charges	**42**	36	6
Corporate Tax Recovery	**(3)**	(11)	8
Earnings	**46**	48	(2)

Energy Deliveries: Energy deliveries at FortisAlberta increased 344 gigawatt hours ("GWh"), or 2.2 per cent, year over year, mainly due to customer growth. During 2008, the number of customers at FortisAlberta increased by approximately 12,700, bringing the total number of customers at FortisAlberta to approximately 461,000 at the end of 2008.

As a significant portion of the Company's distribution revenue is derived from fixed or largely fixed billing determinants, changes in energy deliveries are not directly correlated with changes in revenue.

Revenue: Revenue was $30 million higher than the previous year, mainly due to: (i) a 6.8 per cent increase in customer distribution rates, effective January 1, 2008; (ii) the impact of customer and load growth; (iii) the accrual for collection in future customer distribution rates of the increase in the 2008 allowed ROE to 8.75 per cent from 8.51 per cent, effective January 1, 2008; and (iv) increased franchise fee revenue.

Earnings: Earnings were $2 million lower than the previous year, driven by lower future income tax recoveries primarily associated with the regulator-approved Alberta Electric System Operator ("AESO") charges deferral account. Additionally, higher revenue was partially offset by: (i) higher operating expenses due to increased contracted manpower costs, higher labour and employee-benefit costs associated with increased salaries and number of employees, and higher general operating expenses; (ii) increased amortization costs associated with continued investment in capital assets and higher amortization rates provided for in the 2008/2009 Negotiated Settlement Agreement ("NSA"); and (iii) increased finance charges driven by higher debt levels in support of the Company's significant capital expenditure program.

FortisAlberta's AESO charges deferral account captures variances between amounts charged by the AESO to FortisAlberta for transmission tariffs and amounts collected by FortisAlberta from customers through the transmission tariff component of basic customer rates. Subject to regulatory approval, amounts charged by the AESO in excess of amounts collected from customers are deferred as a regulatory asset for future recovery from customers, and amounts collected from customers in excess of amounts charged are deferred as a regulatory liability for future refund to customers. Generally, there is a two-year lag between the deferral of amounts in the AESO charges deferral account and their collection from, or refund to, customers in rates.

FortisAlberta records income taxes on the cash taxes payable method, as approved by its regulator, except for certain deferral accounts, including the AESO charges deferral account, whereby income taxes are recorded using the liability method. During the third quarter of 2008, FortisAlberta identified that taxable income from operations, before considering impacts associated with the AESO charges deferral account, could be fully offset by utilizing capital cost allowance deductions. Then, by applying the tax deductions related to transmission tariff payments made to the AESO, a tax loss carryforward could be created and a future income tax recovery could be recorded. Under the liability method of recording income taxes, a future income tax asset associated with the tax loss carryforward may be recorded when there is certainty of recovery. The transmission tariff payments made to the AESO are recoverable from customers in the future; therefore, a future income tax asset and future income tax recovery were recorded in each of the third and fourth quarters of 2008, which offset the future income tax liability and future income tax expense created by the AESO charges deferral as it was incurred.

Prior to the third quarter of 2008, FortisAlberta was not deducting transmission tariff payments made to the AESO to create tax loss carryforwards and was not recording the associated future income tax recoveries. This accounting treatment, in effect, resulted in a two-year lag of recording the future income tax impacts between the payments of transmission tariff amounts to the AESO and the timing of their collection from customers. Going forward, fluctuations in corporate income taxes associated with the operation of the AESO charges deferral account are not expected to occur.

During 2007, net future income tax recoveries of approximately $9 million were recorded, primarily due to the sale of amounts deferred to the AESO charges deferral account. In September 2007, the 2006 deferred AESO charges receivable balance of $28 million and, in December 2007, approximately $38 million of the 2007 deferred AESO charges receivable balance, were sold to a Canadian chartered bank and, as a result, the proceeds were recognized in 2007.

Outlook: During 2008, the Alberta Utilities Commission ("AUC") ruled that a 2009 Generic Cost of Capital Proceeding to review ROE levels, adjustment mechanisms and utility capital structures would be appropriate for all gas, electric and pipeline utilities in Alberta that it regulates. As directed by the AUC, FortisAlberta is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, down from the allowed ROE of 8.75 per cent in 2008, pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding.

FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.

In December 2008, FortisAlberta filed a short-form base shelf prospectus for the issuance of up to $350 million in debentures. In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the shelf prospectus. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

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 the forecast gross capital expenditures for 2009 for FortisAlberta is provided under the heading "Liquidity and Capital Resources – Capital Program".

FortisBC

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**3,087**	3,091	(4)
($ millions)			
Revenue	**237**	229	8
Energy Supply Costs	**68**	67	1
Operating Expenses	**67**	69	(2)
Amortization	**34**	31	3
Finance Charges	**28**	26	2
Corporate Taxes	**6**	5	1
Earnings	**34**	31	3

Electricity Sales: Electricity sales at FortisBC decreased 4 GWh, or 0.1 per cent, year over year due to reduced industrial customer loads as a result of a general slowdown in the forestry sector, partially offset by the impact of residential, general service and wholesale customer growth.

Revenue: Revenue was $8 million higher than the previous year, driven by the impact of: (i) a 2.9 per cent increase in electricity rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 9.02 per cent from 8.77 per cent; (ii) a 0.8 per cent increase in electricity rates, effective May 1, 2008, as a result of the flow through to customers of increased purchased power costs from BC Hydro; and (iii) a shift in sales mix from lower-rate to higher-rate customer classes. The increase was partially offset by lower revenue contributions from non-regulated operating, maintenance and management services and lower electricity sales.

Earnings: Earnings were $3 million higher than the previous year. The increase was primarily due to the 2.9 per cent increase in electricity rates, partially offset by higher amortization costs and finance charges related to the Company's significant capital expenditure program.

Operating expenses were $2 million lower than the previous year, mainly due to lower operating expenses associated with non-regulated operating, maintenance and management services, partially offset by the impact of higher labour costs and general inflationary cost increases year over year.

Outlook: FortisBC's allowed ROE for 2009 has been set at 8.87 per cent, down from 9.02 per cent in 2008. In December 2008, FortisBC received regulatory approval of the Company's 2009 Revenue Requirements Application, resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The approval of the 2009 Revenue Requirements Application also included an extension of the performance-based rate-setting ("PBR") mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement.

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 the forecast gross capital expenditures for 2009 for FortisBC is provided under the heading "Liquidity and Capital Resources – Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**5,208**	5,093	115
($ millions)			
Revenue	**517**	491	26
Energy Supply Costs	**337**	327	10
Operating Expenses	**50**	53	(3)
Amortization	**45**	34	11
Finance Charges	**33**	34	(1)
Corporate Taxes	**19**	12	7
Non-Controlling Interest	**1**	1	–
Earnings	**32**	30	2

Electricity Sales: Electricity sales at Newfoundland Power increased 115 GWh, or 2.3 per cent, year over year, primarily due to the combined impact of customer growth and higher average consumption.

Revenue: Revenue in 2008 was $26 million higher than the previous year. The increase was driven by an average increase in customer rates of 2.8 per cent, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 8.95 per cent from 8.60 per cent, and electricity sales growth. The increase in revenue also reflected higher amortization of regulatory liabilities in accordance with prescribed regulatory orders.

Earnings: Earnings were $2 million higher than the previous year, driven by the average 2.8 per cent increase in customer rates, effective January 1, 2008, lower operating expenses driven by the timing of expenses and lower maintenance and pension costs, and lower finance charges. Finance charges decreased due to the refinancing of maturing debt in August 2007 at lower rates.

Amortization costs were higher year over year due to the regulator-approved recovery in customer rates, effective January 1, 2008, of previously deferred amortization costs.

Corporate tax expense increased year over year as a result of higher earnings before corporate taxes, combined with a higher effective corporate income tax rate, which was driven by decreased deductions taken for tax purposes compared to accounting purposes.

Outlook: Newfoundland Power's allowed ROE for 2009 has been set at 8.95 per cent, unchanged from 2008; consequently, there has been no change in base customer rates for 2009.

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 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Other Canadian Electric Utilities[1]

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales *(GWh)*	**2,182**	2,209	(27)
($ millions)			
Revenue	**262**	263	(1)
Energy Supply Costs	**177**	174	3
Operating Expenses	**28**	29	(1)
Amortization	**18**	17	1
Finance Charges	**18**	17	1
Corporate Taxes	**7**	10	(3)
Earnings	**14**	16	(2)

[1] Includes Maritime Electric and FortisOntario

Electricity Sales: Electricity sales at Other Canadian Electric Utilities decreased 27 GWh, or 1.2 per cent, year over year. The decrease was driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

Revenue: Revenue was $1 million lower than the previous year. During 2007, FortisOntario received a one-time refund of approximately $3 million ($2 million after-tax) from Niagara Mohawk Power Corporation ("NIMO") associated with cross-border transmission interconnection agreements. In April 2008, the US Federal Energy Regulatory Commission issued an order stating that the refund should not have been ordered. In May 2008, FortisOntario repaid the refunded amounts to NIMO.

Excluding the impact of the receipt of the $3 million refund in 2007 and its subsequent repayment in 2008, revenue increased $5 million year over year. The increase was primarily due to: (i) the flow through to customers of higher energy supply costs at FortisOntario; (ii) a 1.8 per cent increase in basic electricity rates at Maritime Electric, effective April 1, 2008; and (iii) an average 1.1 per cent increase in basic electricity distribution rates at FortisOntario, effective May 1, 2008, partially offset by the impact of lower electricity sales.

Earnings: Earnings were $2 million lower than the previous year. Excluding the impact of the receipt of the refund in 2007 and its subsequent repayment in 2008, earnings were $2 million higher year over year. The increase was driven by higher basic electricity rates, lower operating expenses and lower effective corporate taxes, partially offset by the impact of lower electricity sales and higher finance charges associated with increased borrowings. Operating expenses in 2007 included costs associated with an early retirement program at FortisOntario.

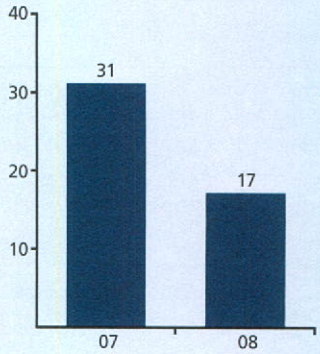
In October 2008, FortisOntario entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc. for a cash payment of approximately $1 million plus the provision of services to integrate Grimsby Power Inc.'s customer information system with FortisOntario's system. Grimsby Power Inc. serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

Outlook: In March 2009, Maritime Electric received regulatory approval of its 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The regulator 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 rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.

Canadian Niagara Power filed a 2009 Cost of Service Application in August 2008 requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The Company expects a decision on the application to be received in April 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Other Canadian Electric Utilities is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

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



Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2008 was $17 million (2007 – $31 million), which represented approximately 7 per cent of the Corporation's total regulated earnings (2007 – 15 per cent). Regulated Electric Utilities – Caribbean assets were approximately $1.0 billion as at December 31, 2008 (December 31, 2007 – $0.8 billion), which represented approximately 10 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 8 per cent).

Regulated Electric Utilities – Caribbean[1]

Financial Highlights

Years Ended December 31	2008[2]	2007	Variance
Average US:CDN Exchange Rate[3]	**1.08**	1.07	0.01
Electricity Sales *(GWh)*	**1,199**	1,054	145
($ millions)			
Revenue	**408**	307	101
Energy Supply Costs	**273**[4]	169	104
Operating Expenses	**55**	49[5]	6
Amortization	**36**	28	8
Finance Charges	**16**	15	1
Corporate Taxes	**2**	2	–
Non-Controlling Interest	**9**	13	(4)
Earnings	**17**	31	(14)

[1] Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

[2] Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008.

[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 2008 included an $18 million (BZ$36 million) charge as a result of a regulatory rate decision by the Public Utilities Commission of Belize in June 2008.

[5] Operating expenses during 2007 included a $4.4 million (US$3.7 million) charge on the disposal of steam-turbine assets at Caribbean Utilities.

Electricity Sales: Electricity sales at Regulated Electric Utilities – Caribbean increased 145 GWh, or 13.8 per cent, year over year, driven by two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end, and customer and general economic growth. The increase was tempered by the loss of electricity sales at Fortis Turks and Caicos as a result of Hurricane Ike, including the delayed reopening for the fall tourist season of several large hotels on the Turks and Caicos Islands. Hurricane Ike was a Category 4 hurricane which struck the Turks and Caicos Islands in early September 2008. The increase was also tempered by the impact on electricity sales associated with the reduction in tourism activities related to global economic conditions towards the end of 2008.

Excluding the two additional months of contribution from Caribbean Utilities, electricity sales increased 6.0 per cent year over year. Electricity sales increased 8.7 per cent in 2007 compared to 2006.

Revenue: Revenue increased $101 million over the previous year; however, annual revenue for 2008 included the two additional months of contribution from Caribbean Utilities and an approximate $6 million favourable impact of foreign currency translation due to the weakening of the Canadian dollar against the US dollar year over year. Excluding the two additional months of contribution from Caribbean Utilities and the favourable impact of foreign currency translation, revenue increased year over year primarily due to: (i) the full flow through of higher fuel and oil costs to customers at Caribbean Utilities under the terms of the Company's new T&D licence; (ii) electricity sales growth; and (iii) an increase in the cost of power component of the average electricity rate at Belize Electricity, effective July 1, 2008. Partially offsetting the above factors were: (i) a decrease in the value-added delivery ("VAD") component of the average electricity rate at Belize Electricity, effective July 1, 2008; (ii) a 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane cost recovery surcharge ("CRS") at Caribbean Utilities, effective January 1, 2008, under the terms of the Company's new T&D licence; and (iii) revenue loss of approximately $2 million at Fortis Turks and Caicos due to Hurricane Ike.

Earnings: Earnings' contribution was $14 million lower than the previous year. Earnings' contribution in 2008 was reduced by $13 million, representing the Corporation's approximate 70 per cent share of $18 million (BZ$36 million) of previously incurred fuel and purchased power costs at Belize Electricity disallowed by the regulator. Earnings' contribution in 2007 was reduced by approximately $2 million, representing the Corporation's share of a charge on the disposal of steam-turbine assets at Caribbean Utilities.

Excluding the one-time items in 2008 and 2007, as described above, earnings were $3 million lower year over year. The impact of electricity sales growth, $1 million of additional earnings' contribution from Caribbean Utilities, and the favourable impact on energy supply costs associated with the movement in deferred fuel costs at Caribbean Utilities was more than offset by: (i) the impact of the 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane CRS at Caribbean Utilities; (ii) the reduction in the VAD component of the average electricity rate at Belize Electricity; (iii) revenue loss of approximately $2 million at Fortis Turks and Caicos due to Hurricane Ike; and (iv) increased operating expenses and amortization costs.

A large portion of the costs of reconnecting customers and restoring electricity service at Fortis Turks and Caicos as a result of Hurricane Ike was capital in nature and, therefore, did not affect earnings.

Excluding the impact of foreign currency translation and the charge on the disposal of steam-turbine assets in 2007, operating expenses increased mainly due to the impact of hiring additional employees and increased general and administrative expenses at Fortis Turks and Caicos, and the timing of maintenance activities. Amortization costs increased as a result of continued investment in capital assets.

In addition to the $18 million charge described above, Belize Electricity's targeted allowed ROA was reduced to 10 per cent from 12 per cent, effective July 1, 2008, which was reflected through a reduction in the VAD component of the average electricity rate.

In April 2008, Caribbean Utilities and the Government of the Cayman Islands entered into a new exclusive 20-year T&D licence and a new non-exclusive 21.5-year generation licence. Under the new T&D licence, customer rates are being set using an initial targeted ROA of 10 per cent, down from 15 per cent as allowed under the previous licence, which was reflected through the reduction in basic electricity rates, effective January 1, 2008.

Outlook: Growth in annual electricity sales at the Corporation's regulated utilities in the Caribbean for 2009 is expected to be approximately 4 per cent, reflecting the anticipated continued global economic downturn that is negatively affecting activity in the tourism, oil and related industries in the Caribbean region.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Regulated Electric Utilities – Caribbean is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

NON-REGULATED

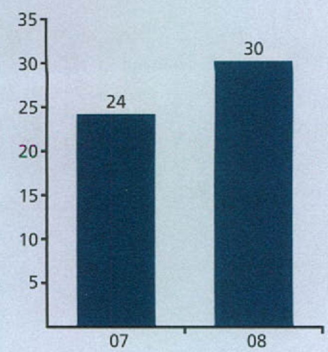
Non-Regulated – Fortis Generation(1)

Financial Highlights

Years Ended December 31	2008	2007	Variance
Energy Sales *(GWh)*	**1,217**	1,122	95
($ millions)			
Revenue	**82**	75	7
Energy Supply Costs	**7**	8	(1)
Operating Expenses	**14**	14	–
Amortization	**10**	10	–
Finance Charges	**8**	10	(2)
Corporate Taxes	**10**	8	2
Non-Controlling Interest	**3**	1	2
Earnings	**30**	24	6

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

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



Energy Sales: Energy sales from Non-Regulated – Fortis Generation increased 95 GWh, or 8.5 per cent, year over year, driven by higher production in central Newfoundland, Belize and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue was $7 million higher year over year. Factors increasing revenue were: (i) higher production; (ii) increased average wholesale energy prices per megawatt hour ("MWh") in Ontario, which were $48.83 for 2008 compared to $47.81 for 2007; and (iii) increased average wholesale energy prices per MWh in Upper New York State, which were US$71.00 for 2008 compared to US$60.73 for 2007.

Earnings: Earnings were $6 million higher year over year, reflecting increased production and lower finance charges driven by the refinancing, in November 2007, of higher-cost external debt with lower-cost inter-company borrowings. Higher average wholesale energy prices also contributed to the increase in earnings year over year.

Outlook: Construction continued in 2008 on the US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is expected to come into service at the beginning of 2010. The earnings' contribution from the Vaca facility, combined with the Corporation's planned consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings upon the expiration, in April 2009, of the Niagara Exchange Agreement associated with the Rankine hydroelectric generating station in Ontario.

Further information on the Vaca hydroelectric generating facility and a summary of forecast non-regulated utility capital expenditures for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

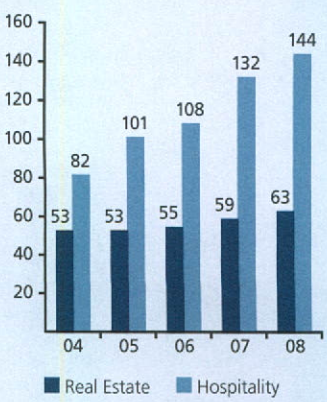
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

($ millions)	**2008**	2007	Variance
Hospitality Revenue	**144**	132	12
Real Estate Revenue	**63**	59	4
Total Revenue	**207**	191	16
Operating Expenses	**135**	123	12
Amortization	**15**	14	1
Finance Charges	**24**	24	–
Corporate Taxes	**10**	6	4
Earnings	**23**	24	(1)

Fortis Properties Revenue *($ millions)*



Revenue: Hospitality revenue was $12 million higher than the previous year, reflecting revenue contribution from the Delta Regina, acquired in August 2007, and the Fairmont Newfoundland hotel, which was acquired for approximately $22 million in November 2008 and rebranded the Sheraton Hotel Newfoundland in January 2009. Hospitality revenue also increased year over year due to improved performance at the Company's operations in Atlantic Canada.

Revenue per available room ("REVPAR") for 2008 was $80.39 compared to $79.31 for 2007. The increase in REVPAR was mainly due to higher average room rates, partially offset by decreased occupancy, at all of the Company's hospitality operating regions.

Real Estate revenue was $4 million higher year over year. The growth in Real Estate revenue was attributable to enhanced performance throughout all of the real estate operating regions, as well as the contribution from the real estate operations of the Delta Regina since August 2007. The occupancy rate of the Real Estate Division was 96.8 per cent as at December 31, 2008, consistent with the rate as at December 31, 2007.

Earnings: Earnings were $1 million lower than the previous year. Excluding a $2 million favourable corporate tax adjustment in 2007 associated with opening future income tax liability balances as a result of lower enacted corporate income tax rates, earnings were $1 million higher year over year. The increase was mainly due to a full year of earnings from the Delta Regina, which was acquired in August 2007.

Outlook: The Hospitality Division currently operates in eight Canadian provinces. Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays.

The Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties 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)	**2008**	2007[1]	Variance
Revenue	**26**	22	4
Operating Expenses	**16**	13	3
Amortization	**8**	6	2
Finance Charges[2]	**80**	70	10
Corporate Tax Recovery	**(23)**	(12)	(11)
Preference Share Dividends	**14**	6	8
Net Corporate and Other Expenses	**(69)**	(61)	(8)

[1] Includes Fortis net corporate expenses and, from May 17, 2007, 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 $4 million higher than the previous year. Higher interest revenue from increased inter-company lending was combined with increased revenue contributions from CWLP. CWLP contributed revenue for a full year in 2008 compared to a partial year in 2007; however, this increase was partially offset by the impact of a decrease in the number of customer contracts at CWLP.

Net Corporate and Other Expenses: Net corporate and other expenses were $8 million higher than the previous year, primarily due to Terasen acquisition-related finance charges and other Terasen corporate-related expenses for a full year in 2008 compared to a partial year in 2007. The increase also reflected higher preference share dividends associated with the 9.2 million First Preference Shares, Series G issued in the second quarter of 2008 for gross proceeds of $230 million and higher business development costs. The increase in net corporate and other expenses was partially offset by a higher corporate tax recovery and higher interest revenue from increased inter-company lending. The corporate tax recovery in 2008 was favourably impacted by a $2 million tax reduction associated with the settlement of historical corporate tax matters at Terasen. The corporate tax recovery in 2007 was reduced as a result of purchase price allocation tax adjustments and by the impact of lower enacted future corporate income tax rates.

In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million. The net proceeds were used to repay short-term debt that was primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes.

Outlook: While currently not significant, financial results of TES are also reported in the Corporate and Other segment. TES expects to increase its activities in the development, building, owning and operating of geothermal energy systems, community piping and energy transfer systems to harness renewable energy sources. TES is entering into agreements with developers to provide alternative thermal energy systems for both residential and commercial development projects in British Columbia. In October 2008, TES signed an agreement to build a centralized heating and cooling system for a new Okanagan lakefront community project. TES will own and operate this alternative energy system. In December 2008, TES signed an agreement to build and manage an alternative district energy system in Coquitlam, British Columbia. The project is expected to commence in the fall of 2009 and be operational as early as 2011.

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 (%) 2007	2008	2009	Supportive Features – Future or Historical Test Year Used to Set Rates
				ROE		Cost of Service ("COS")/ROE
						PBR mechanism through 2009:
TGI	BCUC	35	8.37	8.62	8.47	TGI: 50/50 sharing of earnings above or below the allowed ROE
TGVI	BCUC	40	9.07	9.32	9.17	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisBC	BCUC	40	8.77	9.02	8.87	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 automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisAlberta	AUC	37	8.51	8.75	8.51(1)	COS/ROE
						ROE 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	8.60 +/– 50 bps	8.95 +/– 50 bps	8.95 +/– 50 bps	COS/ROE
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	10.25	10.00	9.75	COS/ROE
						Future Test Year
FortisOntario	OEB (Canadian Niagara Power)	43.3(2)	9.00	9.00	8.39	Canadian Niagara Power – COS/ROE
	Franchise Agreement (Cornwall Electric)					Cornwall Electric – Price cap with commodity cost flow through
						Future Test Year – beginning in 2009
				ROA		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00	10.00(3)	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	15.00	9.00 – 11.00	9.00 – 11.00	COS/ROA
						Rate-cap adjustment mechanism based on published consumer price indices
						Under the new licences, 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(4)	17.50(4)	17.50(4)	COS/ROA
						If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

(1) Interim ROE pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding
(2) Allowed deemed equity component of the capital structure for 2009. For 2008, the allowed deemed equity component of the capital structure was 46.7 per cent.
(3) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application
(4) Amount provided under licence. Actual ROAs achieved in 2007 and 2008 were 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	• In December 2007, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflected the impact of an increase in the allowed ROE for 2008 to 8.62 per cent and 9.32 per cent for TGI and TGVI, respectively. • On April 1, 2008, final regulatory approval for the construction of the 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was received for a total estimated cost of approximately $200 million. • Every three months, TGI and TGVI review natural gas and propane commodity prices 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. Effective April 1, 2008 and July 1, 2008, the BCUC approved increases in the commodity rates charged to TGI customers for natural gas and propane. Effective October 1, 2008, the BCUC approved decreases in the commodity rates charged to TGI customers for natural gas. The commodity cost of natural gas and propane are flowed through to customers without markup. During 2008, no commodity rate changes were made at TGVI. • In December 2008, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2009. The approved rates also reflected the impact of a decrease in the allowed ROE for 2009 to 8.47 per cent and 9.17 per cent for TGI and TGVI, respectively, resulting from the application of automatic ROE adjustment mechanisms. The commodity rate for natural gas will remain unchanged and the commodity rate for propane will decrease effective January 1, 2009. • TGI filed an application with the BCUC in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive regulatory approval for this $27 million project in early 2009 with completion of the project anticipated in 2010. • TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC in the second quarter of 2009. The BCUC approval of rates for 2010 and future years will be required as the current PBR agreements expire at the end of 2009. As part of the rate filings, TGI and TGVI plan to seek a review of the current generic ROE adjustment mechanisms and the deemed equity component of the utilities' capital structures.
FortisBC	• In December 2007, regulatory approval was received for the NSA associated with 2008 revenue requirements resulting in a customer rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's capital expenditure program. Rates for 2008 reflected an allowed ROE of 9.02 per cent. • In April 2008, the BCUC approved an interim increase of 0.8 per cent to FortisBC's customer rates, effective May 1, 2008, as a result of BC Hydro's interim rate increase, which increased FortisBC's cost to purchase power from BC Hydro by 5.06 per cent. • In June 2008, FortisBC filed its 2009 and 2010 Capital Expenditure Plan for gross capital expenditures of approximately $193 million for 2009 and $196 million for 2010. In November 2008, the BCUC denied the costs relating to the Copper Conductor Replacement Project and Advanced Metering Infrastructure Project included in the 2009 and 2010 Capital Expenditure Plan. These projects would have totalled approximately $21 million in 2009 and $27 million in 2010. In February 2009, the BCUC issued its decision on the Company's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million were approved for 2010. An additional $16 million of capital expenditures is subject to further regulatory processes. • In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The rate increase is primarily the result of the Company's capital expenditure program and higher power purchases driven by customer growth and increased electricity demand. Rates for 2009 reflect an allowed ROE of 8.87 per cent as a result of the application of the automatic ROE adjustment mechanism. 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.
FortisAlberta	• Effective January 1, 2008, FortisAlberta became regulated by the AUC due to the separation of the Alberta Energy and Utilities Board into two separate regulatory bodies. • In February 2008, regulatory approval was received of the NSA associated with 2008/2009 revenue requirements, resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately $264 million for 2008 and $296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 allowed ROE of 8.51 per cent. The impact of the increase in the allowed ROE to 8.75 per cent for 2008 was subject to deferral-account treatment and, as such, was recognized as earned in 2008 and will be collected in customer rates in 2009.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2008, the AUC ruled that a review of ROE levels, adjustment mechanisms and utility capital structures in a generic proceeding would be appropriate. In July 2008, the AUC issued its notice of application, preliminary scoping document and minimum filing requirements for the 2009 Generic Cost of Capital Proceeding. The proceeding applies to all gas, electric and pipeline utilities in Alberta that are regulated by the AUC. • In November 2008, FortisAlberta submitted its evidence with respect to the 2009 Generic Cost of Capital Proceeding as requested by the AUC. A hearing is scheduled for the second quarter of 2009. • In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result is a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase is 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 reflect the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. As directed by the AUC, the Company is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, pending the outcome of the 2009 Generic Cost of Capital Proceeding. • FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.
Newfoundland Power	• In December 2007, the PUB approved the Company's NSA associated with the 2008 general rate application, resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase was largely driven by higher amortization costs. The rate increase also reflected the impact of an increase in the allowed ROE to 8.95 per cent for 2008. • The PUB-approved NSA also results in, among other things: (i) the amortization of \$7.2 million in 2008 and \$4.6 million in each of 2009 and 2010 of the remaining \$16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately \$3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three years to five years of certain deferred regulatory balances; and (iv) for 2008 through 2010, the deferral of variations in purchase power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account. • Effective July 1, 2008, the PUB approved an average 5.9 per cent increase in customer electricity rates, 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 increase in customer rates had no impact on Newfoundland Power's earnings in 2008. • 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 replacing aged and deteriorated components of the electricity system. • The Company's allowed ROE of 8.95 per cent remains unchanged for 2009 and, consequently, there has been no change in basic customer rates for 2009.
Maritime Electric	• In January 2008, IRAC approved, as filed, an increase in basic electricity rates of 1.8 per cent, effective April 1, 2008, and approved a maximum allowed ROE of 10.0 per cent for 2008. • In April 2008, IRAC ordered the energy cost adjustment mechanism ("ECAM") amortization period of 12 months to be set at 8 months, effective May 1, 2008. The result is an increase in the flow through in customer rates of the recovery of ECAM over the shorter amortization period. • In September 2008, IRAC approved, as filed, the Company's amendment of approximately \$14 million to its 2008 Capital Budget to reflect the construction of a new transmission line to facilitate the expansion of merchant wind development. The project is being financed entirely by customer contributions. • In November 2008, IRAC approved, as filed, the Company's 2009 Capital Budget Application for approximately \$20 million, before customer contributions. • In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers 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 kWh to 7.7 cents per kWh will result in a decrease in the amount of energy costs to be collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau Nuclear Generating Station 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 rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.
FortisOntario	• In March 2008, the OEB issued its decision relating to the 2008 Incentive Regulation Mechanism ("IRM") application filed by Canadian Niagara Power. The result was an average 1.1 per cent increase in electricity distribution rates for operations in Fort Erie, Port Colborne and Gananoque, effective May 1, 2008. The increase was comprised of a 2.1 per cent increase for inflation, partially offset by a 1.0 per cent decrease for a productivity adjustment. Under the 2008 IRM, Canadian Niagara Power's capital structure for 2008 was deemed at 53.3 per cent debt and 46.7 per cent equity, as part of the OEB's plan to move to a 60 per cent debt and 40 per cent equity capital structure over a three-year period.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• Effective July 1, 2008, retail rates at Cornwall Electric decreased by approximately 6.2 per cent, attributable to a new 11.5-year wholesale electricity supply contract negotiated with Hydro-Québec Energy Marketing by Cornwall Electric on behalf of its customers. The new long-term agreement replaces an existing short-term contract and ensures reliability of supply and rate stability. • In August 2008, Canadian Niagara Power filed a 2009 Cost of Service Application requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The application proposes distribution rate increases of 4.9 per cent, 9.4 per cent and 7.1 per cent for Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009. The proposed increases are primarily driven by the impact of distribution system upgrades. The hearing process associated with the application commenced during the fourth quarter of 2008 and the Company expects a decision on the application to be received in April 2009.
Belize Electricity	• In March 2008, the newly elected Government of Belize repealed December 2007 amendments to the *Electricity (Tariffs, Charges and Quality of Services Standards) Bylaws*. The amendments had simplified Belize Electricity's rate-setting methodology, allowed for improved rate stabilization and settled outstanding matters related to the PUC's Final Decision on electricity rates for the period July 1, 2007 through June 30, 2008. • In March 2008, Belize Electricity filed an application requesting an increase in the cost of power component of the average electricity rate by 15 per cent, or BZ6.5 cents per kilowatt hour ("kWh"), as a result of the rapid increase in the cost of power due to increasing world oil prices. The application was disallowed by the PUC which cited that, in the interim, a decrease in the Company's operating expenses and capital expenditure levels would help offset the impact on cash flow of the increasing cost of power. Additionally, the PUC indicated it would defer its detailed analysis of the high deferrals of cost of power into Belize Electricity's cost of power rate stabilization account ("CPRSA") until the Annual Tariff Review Proceeding for the annual tariff period for July 1, 2008 to June 30, 2009. • In April 2008, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2008 to June 30, 2009 ("2008/2009 Rate Application") requesting a 13.4 per cent increase in the average electricity rate, as a result of an increase in the cost of power component of the rate and an increase in the recovery of the CPRSA. • In May 2008, the PUC issued its Initial Decision on Belize Electricity's 2008/2009 Rate Application. The Initial Decision denied any average rate increase and approved, among other things, a retroactive adjustment to Belize Electricity's CPRSA. Belize Electricity objected to the Initial Decision, which resulted in a review of the Initial Decision by a PUC-appointed Independent Expert. The report of the Independent Expert reiterated many of Belize Electricity's concerns pertaining to the Initial Decision. • In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application which rejected most of the recommendations of the Independent Expert and failed to increase the overall average electricity rate. 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. The Final Decision would have the impact of reducing the Corporation's share of Belize Electricity's earnings by approximately $5 million over a 12-month period. The Final Decision does not impact the Corporation's non-regulated generation operations in Belize. • As a direct result of the 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 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 retroactive effective September 1, 2008, allows for the collection from, or rebate to, customers of actual costs of power which vary 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. • Changes made in electricity legislation by the Government of Belize and the PUC and the June 2008 Final Decision and 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 outcome of the proceedings is indeterminable at this time.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Caribbean Utilities	• In December 2007, an Agreement in Principle ("AIP") was reached with the Government of the Cayman Islands on the terms of a new exclusive T&D licence and a new non-exclusive generation licence. • In April 2008, the new licences were granted. The terms of the new licences included competition for future generation capacity and general promotion of renewable sources of energy. The T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The generation licence is for a period of 21.5 years, expiring September 2029. The terms of the new licences remained substantially the same as the terms outlined in the AIP. • Effective January 1, 2008, as a result of the AIP and subsequent granting of the new licences, basic customer rates were reduced by 3.25 per cent, the hurricane CRS was removed, a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, and basic rates were restructured to extract all fuel costs and licence fee amounts which are now being flowed through to customers. The 3.25 per cent reduction in basic rates reduced annual revenue by approximately US$2.1 million. Additionally, Caribbean Utilities has forgone US$2.6 million of revenue in 2008 as a result of the early elimination of the hurricane CRS. A new fuel and oil rate factor was also established to provide for the full flow through of fuel and oil costs to customers. • Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review and adjustment each June thereafter. Under the new T&D licence, a mechanism will be used to adjust basic rates in accordance with a formula that is based on published CPIs, thereby taking inflation into account. The rate-adjustment mechanism is designed to maintain Caribbean Utilities' allowed ROA in a targeted range of 9 per cent to 11 per cent, down from an allowed ROA of 15 per cent permitted under the previous licence. The recently amended *Electricity Regulatory Authority Law* (2005 Revision) provides for the conduct of a competitive bid process to be managed by the ERA for new generating capacity and the replacement of retired generating capacity. The first competitive process under the new generation licence began in May 2008 with a filing of a Certificate of Need by Caribbean Utilities for the installation of 16 MW of additional generating capacity in each of 2011 and 2012. Based on slowing economic growth, the Company has advised the ERA that the capacity is not required until a year later. In March 2009, the ERA approved the Certificate of Need for 16 MW of generating capacity in each of 2012 and 2013. • In July 2008, Caribbean Utilities began a formal request for expressions of interest from qualified wind-generation developers for a wind-generation project for up to 10 MW. The ERA has endorsed this initiative and any power purchase agreements or generating licence arising from this initiative will be subject to ERA approval. • In July 2008, Caribbean Utilities filed with the regulator a Five-Year Capital Investment Plan ("CIP") totalling US$255 million. • In December 2008, Caribbean Utilities filed with the regulator a revised Five-Year CIP as a result of the change in the Company's fiscal year end. The revised CIP still totalled US$255 million, including approximately US$72 million related to new generation that is expected to be solicited. In January 2009, the regulator requested that the Company further review its non-generation capital expenditures to reflect the current economic environment and lower growth projections. A revised CIP totalling US$246 million was subsequently submitted to the ERA. A decision on the revised CIP is expected during the first quarter of 2009. • In January 2009, the ERA approved a new customer-owned renewable energy tariff that will allow customers on Grand Cayman to connect renewable energy systems to the Company's distribution system and generate their own power from renewable energy while remaining connected to Caribbean Utilities' grid. The Company expects to be able to connect customers to the grid by the end of the first quarter of 2009.
Fortis Turks and Caicos	• In May 2008, Fortis Turks and Caicos received approval from the Government of the Turks and Caicos Islands to supply wholesale electricity under an exclusive licence to Dellis Cay on the Turks and Caicos Islands. • 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, 2008 and December 31, 2007.

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Accounts receivable	46	The increase was primarily due to the impacts of cooler weather and an increase in the commodity cost of natural gas charged to customers at the Terasen Gas companies in December 2008 compared to December 2007.
Regulatory assets – current and long-term	48	The increase was driven by the deferral of 2008 AESO charges at FortisAlberta, an increase in the deferral of other post-employment benefit costs and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase was partially offset by a decrease in the deferral of the commodity cost of natural gas at the Terasen Gas companies and the cost of fuel and purchased power at Belize Electricity. The decrease at Belize Electricity was driven by an $18 million (BZ$36 million) adjustment as a result of a regulatory rate decision in 2008.
Inventories	22	The increase was primarily associated with inventories of natural gas at the Terasen Gas companies due to an increase in the average price of natural gas in December 2008 compared to December 2007.
Deferred charges and other assets	100	The increase was mainly due to the reclassification of hydroelectric generating facility assets of the Exploits Partnership from utility capital assets as at December 31, 2008. The increase was also due to $31 million in contributions made by FortisAlberta to the AESO for transmission capital projects during 2008 and an increase in deferred defined benefit pension costs. Refer to the "Contingencies" section of this MD&A for a further discussion of the Exploits Partnership.
Future income tax assets – long-term	17	The increase primarily related to future income tax recoveries associated with unrealized foreign exchange losses incurred upon the translation of the Corporation's US dollar-denominated long-term debt due to the weakening of the Canadian dollar against the US dollar.
Utility capital assets	619	The increase primarily related to $890 million invested in electricity and gas systems combined with the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets. The increase was partially offset by customer contributions and amortization for 2008 and the reclassification of hydroelectric generating facility assets of the Exploits Partnership to deferred charges and other assets as at December 31, 2008.
Income producing properties	22	The increase primarily related to the acquisition of the Fairmont Newfoundland hotel in November 2008.
Goodwill	31	The increase primarily related to the impact of foreign exchange on the translation of US dollar-denominated goodwill and goodwill associated with the Corporation's additional investment in Caribbean Utilities as a result of the Corporation's participation in Caribbean Utilities' Rights Offering in August 2008. The increase was partially offset by a $6 million reduction associated with the recognition in 2008 of the benefit of tax losses at Terasen which related to periods prior to the Corporation's ownership of Terasen.
Short-term borrowings	(65)	The decrease was primarily due to the repayment of short-term borrowings by Maritime Electric and TGI with proceeds from the issuance of long-term debt.
Accounts payable and accrued charges	81	The increase was primarily due to higher natural gas costs payable at the Terasen Gas companies due to increased consumption as a result of cooler weather in December 2008 compared to December 2007, combined with higher accounts payable at Maritime Electric due to the timing of payments of energy supply costs. The increase was partially offset by a decrease in amounts owing at FortisAlberta due to the timing of payments to the AESO for transmission costs.
Income taxes payable	36	The increase was mainly due to taxes associated with regulatory-deferral accounts at the Terasen Gas companies combined with the timing of income tax payments and the accrual of current income taxes at the Terasen Gas companies and Newfoundland Power. The increase was partially offset by an approximate $17 million payment associated with the Québec Trust tax settlement at Terasen.
Regulatory liabilities – current and long-term	54	The increase was driven by the deferral, during the latter part of 2008, of amounts owing to customers due to lower actual commodity cost of natural gas at the Terasen Gas companies and lower cost of fuel and purchased power at Belize Electricity compared to amounts collected in customer rates and an increase in the regulatory provision for future asset removal and site restoration costs. The increase was partially offset by a decrease in the unbilled revenue liability at Newfoundland Power in accordance with PUB-approved amortization.
Deferred credits	16	The increase was primarily due to an increase in supplementary defined benefit pension and other post-employment benefit liabilities.

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007 (cont'd)

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Long-term debt and capital lease obligations (including current portion)	65	The increase was primarily due to the issuance of long-term debt and the impact of foreign exchange on the translation of foreign currency-denominated debt, partially offset by a net decrease in committed credit-facility borrowings, as well as by regularly scheduled debt maturities and repayments. The issuance of long-term debt, primarily to repay committed credit-facility borrowings, short-term borrowings and maturing long-term debt, was comprised of a $250 million unsecured debenture offering by TGI, a $250 million unsecured debenture offering by TGVI, a $100 million senior unsecured debenture offering by FortisAlberta and a $60 million secured first mortgage bond issue by Maritime Electric. The net $309 million decrease in committed credit-facility borrowings was driven by net repayments at the Terasen Gas companies and the Corporation, partially offset by net borrowings at FortisAlberta and FortisBC. The regularly scheduled debt repayments included the repayment of $188 million of maturing debt at TGI and $200 million of maturing debt at Terasen Inc.
Non-controlling interest	30	The increase primarily related to the impact of foreign exchange on the translation of foreign currency-denominated non-controlling interest amounts, combined with the Corporation's non-controlling interest in Caribbean Utilities' US$28 million Rights Offering in August 2008. The increase was partially offset by the Corporation's non-controlling interest in the net loss incurred at Belize Electricity in 2008, which was mainly the result of the PUC's decision on the Company's 2008/2009 Rate Application.
Shareholders' equity	670	The increase was driven by a $300 million common share issue ($291 million net of after-tax expenses) and a $230 million preference share issue ($225 million net of after-tax expenses), combined with net earnings reported for 2008, 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 and a decrease in accumulated other comprehensive loss.

Liquidity and Capital Resources

The table below outlines the Corporation's sources and uses of cash in 2008, as compared to 2007, followed by a discussion of the nature of the variances in cash flows year over year.

Summary of Cash Flows

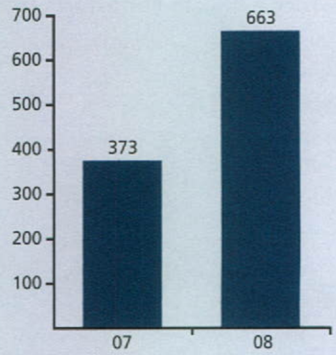
Years Ended December 31

($ millions)	**2008**	2007	Variance
Cash, Beginning of Year	**58**	41	17
Cash Provided By (Used In)			
Operating Activities	**663**	373	290
Investing Activities	**(854)**	(2,033)	1,179
Financing Activities	**196**	1,680	(1,484)
Foreign Currency Impact on Cash Balances	**3**	(3)	6
Cash, End of Year	**66**	58	8

Management Discussion and Analysis

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2008 was $290 million higher than the previous year. An increase in cash flow from operating activities, after working capital adjustments, of $380 million at the Terasen Gas companies was combined with the impact of favourable working capital changes at Newfoundland Power. The Terasen Gas companies contributed to the financial results of the Corporation for a full year in 2008 compared to a partial year in 2007. The increase was partially offset by lower cash flow from operating activities, after working capital adjustments, at FortisAlberta. However, cash from operating activities in 2007 at FortisAlberta reflected the favourable impact of the sale of amounts in the Company's AESO charges deferral account, corporate tax refunds received and the timing of the payment of AESO transmission costs.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2008 was approximately $1.2 billion lower than the previous year. Investing activities in 2007, however, included the impact of the approximate $1.3 billion cash payment for the acquisition of Terasen in May 2007 and the approximate $50 million acquisition of the Delta Regina in August 2007. Excluding the impact of the acquisitions of Terasen and the Delta Regina in 2007, cash used in investing activities was $124 million higher year over year. The increase was driven by higher utility capital expenditures and changes in deferred charges, other assets and deferred credits, partially offset by an increase in contributions received in aid of construction and an increase in proceeds from the sale of capital assets. In January 2008, TGI received $14 million of proceeds associated with the sale of surplus land in December 2007. Investing activities for 2008 also included the approximate $22 million acquisition of the Fairmont Newfoundland hotel in November 2008.

Gross utility capital expenditures in 2008 were $890 million, $100 million higher than last year. The increase was driven by the Terasen Gas companies and FortisAlberta, partially offset by lower capital spending at FortisBC. The net increase in the use of cash associated with changes in deferred charges, other assets and deferred credits of $27 million was driven by higher contributions by FortisAlberta to AESO transmission capital projects. Contributions received in aid of construction in 2008 were $12 million higher than last year, primarily related to the Terasen Gas companies and Maritime Electric, partially offset by lower contributions received at FortisAlberta.

Financing Activities: Cash provided by financing activities in 2008 was approximately $1.5 billion lower than the previous year. Financing activities in 2007 included the issuance of common shares, for gross proceeds of $1.15 billion, to finance a significant portion of the cash purchase price of Terasen. Excluding the impact of financing the acquisition of Terasen in 2007, cash provided by financing activities was $382 million lower in 2008 compared to 2007. The decrease was mainly due to higher net repayments of short-term and committed credit-facility borrowings, lower proceeds from long-term debt and higher repayments of long-term debt. The decrease was partially offset by net proceeds from the $300 million common share issue during the fourth quarter of 2008 and the $230 million preference share issue during the second quarter of 2008 compared to net proceeds from a $150 million common share issue during the first quarter of 2007.

Net repayments of short-term borrowings were $69 million for 2008 compared to proceeds from net short-term borrowings of $103 million in 2007. The net repayments in 2008 were driven by Maritime Electric and the Terasen Gas companies, with partial proceeds from the issuance of long-term debt in 2008.

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 2008 compared to 2007 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	2008	2007	Variance
Terasen Gas Companies	496[(1)(2)]	250[(3)]	246
FortisAlberta	99[(4)]	110[(5)]	(11)
FortisBC	–	104[(6)]	(104)
Newfoundland Power	–	70[(7)]	(70)
Maritime Electric	60[(8)]	–	60
Caribbean Utilities	–	48[(9)]	(48)
Corporate – Fortis Inc.	–	209[(10)]	(209)
Other	7	6	1
Total	662	797	(135)

(1) Issued February 2008, $250 million 6.05% Senior Unsecured Debentures by TGVI, due February 2038. The net proceeds were used to repay committed credit-facility borrowings.

(2) Issued May 2008, $250 million 5.80% Medium-Term Unsecured Note Debentures by TGI, due May 2038. The net proceeds were primarily used to repay maturing $188 million 6.20% debentures and short-term borrowings.

(3) Issued October 2007, $250 million 6.00% Medium-Term Unsecured Note Debentures by TGI, due October 2037. The net proceeds were used to repay maturing $250 million 6.50% long-term debt.

(4) Issued April 2008, $100 million 5.85% Senior Unsecured Debentures, due April 2038. The net proceeds were used to repay committed credit-facility borrowings.

(5) Issued January 2007, $110 million 4.99% Senior Unsecured Debentures, due January 2047. The net proceeds were used to repay committed credit-facility borrowings.

(6) Issued July 2007, $105 million 5.90% Senior Unsecured Debentures, due July 2047. The net proceeds were used to repay committed credit-facility borrowings and for general corporate purposes, including capital expenditures.

(7) Issued August 2007, $70 million 5.90% Secured First Mortgage Sinking Fund Bonds, due August 2037. The net proceeds were used to repay committed credit-facility borrowings and maturing $31.5 million 11.875% Secured First Mortgage Sinking Fund Bonds.

(8) Issued April 2008, $60 million 6.05% Secured First Mortgage Bonds, due April 2038. The proceeds were used to repay short-term borrowings.

(9) Issued June 2007, US$30 million 5.65% Senior Unsecured Notes, due June 2022. Issued November 2007, US$10 million 5.65% Senior Unsecured Notes, due June 2022. The net proceeds were used to repay debt and finance capital expenditures.

(10) Issued September 2007, US$200 million 6.60% Senior Unsecured Notes, due September 2037. The net proceeds were primarily used to repay committed credit-facility borrowings associated with the Terasen acquisition and for general corporate purposes.

Repayment of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	2008	2007	Variance
Terasen Gas Companies	(193)	(250)	57
Newfoundland Power	(5)	(36)	31
Caribbean Utilities	(11)	(18)	7
Fortis Generation – BECOL	–	(28)	28
Fortis Properties	(13)	(20)	7
Corporate – Terasen Inc.	(200)	–	(200)
Other	(9)	(11)	2
Total	(431)	(363)	(68)

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

($ millions)	2008	2007	Variance
Terasen Gas Companies	(261)	–	(261)
FortisAlberta	101	(76)	177
FortisBC	31	(21)	52
Newfoundland Power	(1)	(2)	1
Corporate	(179)	124[(1)]	(303)
Total	(309)	25	(334)

(1) Borrowings under the Corporation's committed credit facility during 2007 primarily related to financing, on an interim basis, the remaining $125 million net cash purchase price of Terasen on May 17, 2007, in addition to certain acquisition costs and common share issue costs; to repay certain short-term indebtedness assumed upon the acquisition of Terasen; to finance a significant portion of the cash purchase price of the Delta Regina in August 2007; and in support of general corporate activities. Indebtedness under the credit facility was partially repaid with partial net proceeds from the $150 million common share issue and the issuance of US$200 million unsecured notes.

Borrowings by the utilities under credit facilities 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 and/or cash from operations. 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 under the Corporation's share purchase and stock option plans in 2008 were $21 million compared to $23 million in 2007. 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. In May 2007, the Corporation publicly issued 44.3 million common shares for gross proceeds of approximately $1.15 billion ($1.1 billion net of costs) to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million common shares were publicly issued for gross proceeds of approximately $150 million ($143 million net of costs). Partial net proceeds from the common share issue in January 2007 were used to repay indebtedness incurred under the Corporation's committed credit facility. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

During the second quarter of 2008, the Corporation issued 9.2 million First Preference Shares, Series G for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million 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.

Common share dividends were $162 million for 2008, up $34 million from 2007. The increase was due to an increase in the number of common shares outstanding, primarily as a result of the issuance of common shares pursuant to the Terasen acquisition in May 2007 and a higher dividend declared per common share compared to 2007. The dividend declared per common share in 2008 was $1.01, while the dividend declared per common share in 2007 was $0.88.

Preference share dividends increased $8 million year over year as a result of the dividends associated with the $230 million preference shares that were issued during the second quarter of 2008.

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2008, are outlined in the following table.

Contractual Obligations

As at December 31

($ millions)	**Total**	≤ 1 year	> 1–3 years	4–5 years	> 5 years
Long-term debt[1]	**5,122**	240	319	335	4,228
Brilliant Terminal Station[2]	**63**	3	5	5	50
Gas purchase contract obligations[3]	**466**	416	50	–	–
Power purchase obligations					
FortisBC[4]	**2,829**	40	76	78	2,635
FortisOntario[5]	**561**	45	94	99	323
Maritime Electric[6]	**72**	52	2	2	16
Belize Electricity[7]	**16**	4	4	2	6
Capital cost[8]	**400**	16	41	41	302
Joint-use asset and shared service agreements[9]	**62**	4	7	6	45
Office lease – FortisBC[10]	**19**	1	4	2	12
Operating lease obligations[11]	**166**	18	33	29	86
Other	**25**	4	10	6	5
Total	**9,801**	843	645	605	7,708

[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 and long-term debt 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

2008 and TGVI is expected to make an $8 million repayment on the loans in 2009 (2008 – $6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was $61 million with $8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's revenue deficiency deferral account and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

(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, 2008.

(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 natural flow 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. These contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. 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.

(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 and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's contractual obligations.

(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 the NB Power Point Lepreau Nuclear Generating Station 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 the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 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 extensions 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, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

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-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

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: As at December 31, 2008, the fair value of the Corporation's consolidated defined benefit pension plan assets was $579 million compared to $674 million as at December 31, 2007, which represented a 14 per cent decline in asset value. Details of the nature of the changes in the fair value of the plan assets are disclosed in Note 20 to the Corporation's 2008 Consolidated Financial Statements. The decrease in the fair value of the pension plan assets during 2008 was mainly driven by unfavourable market conditions during the year.

The decline in the fair value of the pension plan assets is expected to have the effect of increasing the Corporation's future consolidated defined benefit pension plan funding obligations. The amount of the increase will not be determinable until the next completion of actuarial valuations, which for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen is expected during 2009, related to December 31, 2008 valuation dates. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

Fortis expects any additional defined benefit pension plan funding requirements to be sourced primarily from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

Based on the last completion of actuarial valuations, required defined benefit pension plan funding contributions are expected to total approximately $17 million for 2009 and $12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome of the December 31, 2008 actuarial valuations.

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 is presented in the following table.

Capital Structure

As at December 31	2008		2007	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash)(1)	**5,468**	**59.5**	5,476	64.3
Preference shares(2)	**667**	**7.3**	442	5.2
Common shareholders' equity	**3,046**	**33.2**	2,601	30.5
Total	**9,181**	**100.0**	8,519	100.0

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

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

The improvement in the capital structure from December 31, 2007 was primarily due to a $300 million ($291 million net of after-tax expenses) common share issue in December 2008 and a $230 million ($225 million net of after-tax expenses) preference share issue in the second quarter of 2008. The capital structure was also favourably impacted by net earnings applicable to common shares, net of common share dividends, of $83 million during 2008.

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)

During the fourth quarter of 2008, S&P and DBRS confirmed the Corporation's unsecured corporate debt credit ratings. 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 2008, approximately $94 million in maintenance and repairs was expensed compared to approximately $87 million during 2007. The increase year over year largely reflected inclusion of the financial results of the Terasen Gas companies for a full year in 2008.

Actual gross consolidated capital expenditures for 2008 were $904 million, comparable to the estimate for 2008 as disclosed at December 31, 2007.

A summary of gross capital expenditures for 2008 by segment and asset category is provided in the following table.

Gross Capital Expenditures

Year Ended December 31, 2008

($ millions)	Terasen Gas Companies(1)	Fortis Alberta(1)(2)	Fortis BC(1)	Newfoundland Power(1)	Other Regulated Utilities – Canadian(1)	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated – Utility(3)**	**Fortis Properties**	**Total(4)**
Generation	–	–	16	5	2	**23**	**37**	**18**	**–**	**78**
Transmission	93	–	47	6	14	**160**	**16**	**–**	**–**	**176**
Distribution	108	220	37	48	27	**440**	**43**	**–**	**–**	**483**
Facilities, equipment, vehicles and other	4	41	7	4	2	**58**	**13**	**10**	**14**	**95**
Information technology	15	41	10	4	1	**71**	**1**	**–**	**–**	**72**
Total	220	302	117	67	46	**752**	**110**	**28**	**14**	**904**

(1) Includes asset removal and site restoration expenditures which are permissible in rate base

(2) Excludes payments of $31 million made to the AESO for investment in transmission capital projects

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

(4) Includes expenditures associated with assets under construction

Gross consolidated capital expenditures for 2009 are expected to be approximately $1 billion. Planned capital expenditures are based on detailed forecasts of customer 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 summary of forecast gross capital expenditures for 2009 by segment and by asset category is provided in the following table.

Forecast Gross Capital Expenditures

Year Ending December 31, 2009

($ millions)	Terasen Gas Companies[1]	Fortis Alberta[2]	Fortis BC[1]	Newfoundland Power[1]	Other Regulated Utilities – Canadian[1]	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated – Utility[3]**	**Fortis Properties**	**Total[4]**
Generation	–	–	22	10	3	**35**	**43**	**34**	**–**	**112**
Transmission	160	–	66	5	2	**233**	**17**	**–**	**–**	**250**
Distribution	87	186	37	42	26	**378**	**36**	**1**	**–**	**415**
Facilities, equipment, vehicles and other	8	22	7	4	1	**42**	**19**	**21**	**33**	**115**
Information technology	32	84	10	4	2	**132**	**3**	**–**	**–**	**135**
Total	287	292	142	65	34	**820**	**118**	**56**	**33**	**1,027**

(1) Includes forecast asset removal and site restoration expenditures which are permissible in rate base
(2) Excludes forecast payments of $31 million to be made to the AESO for investment in transmission capital projects
(3) Includes forecast non-regulated generation, non-regulated gas utility and Corporate capital expenditures
(4) Includes forecast expenditures associated with assets under construction

The percentage breakdown of 2008 actual and 2009 forecast gross capital expenditures among growth, sustaining and other is as follows:

Gross Capital Expenditures

Year Ended December 31

(%)	**Actual 2008**	Forecast 2009
Growth	**49**	45
Sustaining[1]	**33**	31
Other[2]	**18**	24
Total	**100**	100

(1) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets
(2) Related to facilities, equipment, vehicles, information technology systems and other assets

Significant capital expenditure projects in 2008 and 2009 are summarized in the table below.

Significant Capital Projects

($ millions) **Company**	**Nature of project**	**Actual 2008[1]**	Forecast 2009[1]	Forecast costs to complete after 2009[1]	Year of expected completion
Terasen Gas Companies	Liquefied natural gas storage facility – Vancouver Island	**47**	74	93	2011
	Squamish-to-Whistler pipeline lateral and system conversion	**13**	16	–	2009
	Customer Information System	**–**	14[2]	_[2]	_[2]
	Gateway Infrastructure Project	**–**	15	15	2010
	Fraser River South Bank South Arm Rehabilitation Project	**1**	25	1	2010
FortisAlberta	Automated Meter Infrastructure technology	**17**	73	27	2010
FortisBC	Okanagan Transmission Reinforcement Project	**3**	32	100	2011
	New substations and associated transmission lines	**27**	16	73	2013
	Generation asset Upgrade and Life-Extension Program	**11**	14	39	2012
Caribbean Utilities	New 16-MW diesel-fired generating unit	**8**	21	–	2009
Non-Regulated – Fortis Generation	19-MW Vaca hydroelectric generating facility in Belize	**18**	34	–	Beginning of 2010
Fortis Properties	Expansion of Holiday Inn Express Kelowna	**2**	12	–	Beginning of 2010

(1) Includes allowance for funds used during construction
(2) The total cost and timing of the project are subject to regulatory approval. An application requesting approval of the project is expected in 2009.

In April 2008, TGVI received approval from the BCUC to proceed with the engineering, procurement and construction ("EPC") of the liquefied natural gas ("LNG") storage facility on Vancouver Island for a total cost of approximately $200 million. As a result, the Company entered into an EPC contract with a third party for the construction of the facility. The contract includes approximately $55 million to be paid in US dollars. As a result, TGVI entered into a three-year US dollar forward-purchase contract which will mitigate currency fluctuations on the US dollar portion of the EPC contract. Construction commenced on the LNG storage facility during the second quarter of 2008 with completion of the project expected in late 2011.

TGVI's construction of a 50-kilometre pipeline lateral from Squamish to Whistler continued in 2008 and, as at December 31, 2008, approximately 49 kilometres of the pipeline had been constructed. Originally scheduled to be completed by summer 2008, the pipeline lateral is now expected to be completed in April 2009, later than originally planned due to changes in the way the Company can sequence the pipeline construction as a result of the Government of British Columbia's Sea-to-Sky Highway Improvement Project Plan ("Highway Project"). The pipeline is being built in conjunction with the Highway Project and the pipeline route mainly falls within the highway right of way. Upon completion of the pipeline, the Company will convert the Resort Municipality of Whistler from propane to natural gas during spring and summer of 2009. The total cost of the pipeline lateral and system conversion is expected to be approximately $51 million.

TGI is currently conducting a review of the existing customer care services arrangements with its outsourced provider to ensure the needs of customers will be met in the future. Later in 2009, TGI expects to file an application with the BCUC requesting approval and funding for the development of a replacement customer information system with capital spending related to this project estimated at $14 million for 2009.

As a result of the Government of British Columbia's Gateway Initiative, a regional infrastructure program to improve the movement of people, goods and transit throughout Greater Vancouver, TGI will be required to relocate some of its pipeline system. Total capital spending for the project, which is expected to be fully funded from contributions from the Government of British Columbia, is estimated at approximately $30 million, with $15 million expected to be spent in 2009.

In the fourth quarter of 2008, TGI filed an application with the BCUC requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive approval for this project in early 2009 with completion of the project anticipated in 2010. The total capital cost of the project is anticipated to be approximately $27 million.

During the third quarter of 2008, FortisAlberta began the second phase of deployment of the replacement of conventional meters with new Automated Meter Infrastructure ("AMI") technology. This phase is part of an overall $124 million project to convert all of FortisAlberta's customers to AMI technology over a four-year period that began in 2007.

In October 2008, the BCUC approved FortisBC's proposed $141 million Okanagan Transmission Reinforcement Project, which was included in FortisBC's 2009 and 2010 Capital Expenditure Plan. The project relates to upgrading the existing overhead transmission line from 161 kilovolts ("kV") to 230 kV from Vaseux Lake to Oliver and Penticton and building a new 230-kV transmission line from Vaseux Lake to Penticton and a substation. FortisBC anticipates that construction of the project will begin in spring 2009 for expected completion in 2011.

During 2008, work continued at FortisBC on a number of new substations and associated transmission lines. Approximately 82 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

Since 1998, FortisBC's hydroelectric generating facilities have been subject to an Upgrade and Life-Extension Program which is forecast to conclude in 2012. Approximately 57 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

In April 2008, Caribbean Utilities entered into an agreement to purchase a 16-MW diesel generating unit and related equipment from a supplier in Germany for approximately US$24 million over the period 2008 and 2009, with the unit scheduled for completion in September 2009.

Construction continued in 2008 on the US$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generating facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. The facility is expected to come into service at the beginning of 2010, slightly later than originally planned due to labour and weather-related delays.

Late in 2008, Fortis Properties commenced the expansion of its Holiday Inn Express Kelowna hotel which includes adding 70 rooms and 4,000 square feet of meeting room space. Completion of the expansion is expected by January 2010 at a total capital cost of approximately $14 million.

Over the next five years, consolidated gross capital expenditures are expected to total approximately $4.5 billion. Approximately $3.1 billion of the capital spending is expected be incurred at the regulated electric utilities, driven by FortisAlberta, FortisBC and the Corporation's regulated utility operations in the Caribbean. Approximately $1.2 billion is expected to be incurred at the regulated gas utilities. Capital expenditures at the regulated utilities are subject to regulatory approval. Non-regulated capital expenditures are expected to total approximately $200 million over the same period.

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 which 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 2009 as a result of the anticipated continued downturn in the global economy. The subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately $240 million in 2009 and to average approximately $180 million annually over the next five years. The combination of available credit facilities, as discussed in more detail below, and low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to the 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, 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 $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default of a $61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. A further discussion of the Exploits Partnership is provided in the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Fortis and its subsidiaries, except for Belize Electricity and debt associated with the Exploits Partnership as described above, were in compliance with debt covenants as at December 31, 2008 and are expected to remain compliant in 2009.

Credit Facilities: As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which approximately $1.5 billion was unused, including $568 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.

In 2009, FortisBC expects to have the term of its committed $100 million 364-day revolving credit facility extended for a further year beyond its original maturity in May 2009. Terasen Inc. expects to renew its $100 million committed revolving credit facility, which matures in May 2009. In March 2009, Maritime Electric renegotiated its $50 million demand credit facility and had it converted into a 364-day revolving committed credit facility.

The cost of renewed and extended credit facilities may increase as a result of current economic conditions and tightened credit markets; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its subsidiaries in 2009 as the majority of the committed credit facilities have maturities beyond 2009.

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

Credit Facilities

As at December 31 *($ millions)*	Corporate and Other	Regulated Utilities	Fortis Properties	**Total 2008**	Total 2007
Total credit facilities	715	1,500	13	**2,228**	2,234
Credit facilities utilized					
Short-term borrowings	–	(410)	–	**(410)**	(475)
Long-term debt	(32)	(192)	–	**(224)**	(530)
Letters of credit outstanding	(1)	(102)	(1)	**(104)**	(159)
Credit facilities available	682	796	12	**1,490**	1,070

At December 31, 2008 and December 31, 2007, 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, 2007 to December 31, 2008 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2008 are detailed in Note 26 to the 2008 Consolidated Financial Statements.

Corporate and Other

Letters of credit of $50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Regulated Utilities

In April 2008, FortisBC renegotiated and amended its $150 million unsecured committed revolving credit facility, extending the maturity date of the $50 million portion of the facility to May 2011 from May 2010 and extending the $100 million portion to May 2009 from May 2008. The Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval.

In April 2008, Maritime Electric repaid all outstanding borrowings under its $25 million unsecured credit facility with partial proceeds from a $60 million bond issue. The credit facility matured in May 2008 and was not renewed.

In July 2008, TGI renegotiated, on substantially similar terms, its $500 million unsecured committed revolving credit facility, extending the maturity date of the facility to August 2013 from August 2012.

In August 2008, Newfoundland Power renegotiated, on substantially similar terms, its $100 million committed revolving credit facility, extending the maturity date to August 2011 from January 2009.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity, requiring the Company to repay approximately BZ$4 million outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ$5 million credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the Scotiabank credit facility was undrawn. A continuation of lower energy supply costs should provide Belize Electricity with some liquidity relief in the near term.

Off-Balance Sheet Arrangements

As at December 31, 2008, 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 regulators and local governments 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 2008 (2007 – 90 per cent), while approximately 83 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2008 (2007 – 81 per cent). The regulated utilities, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. The uncertainties include approvals by the respective regulatory authorities 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. Generally, the ability of the utilities to recover the actual costs of providing services and earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities 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 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 on 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.

Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions, which govern the competitive wholesale and retail electricity markets, are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return 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, TGVI and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGVI expire in 2009. In December 2008, the PBR mechanism at FortisBC was extended for the periods from 2009 to 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a different formula. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the 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.

Further information on the new PBR mechanism at 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 which could result in significant operational and/or environmental liability. 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 earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. 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 their 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 costs of services 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 as to 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 growth 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, gas distribution volumes may not grow as quickly as in the past. 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 activity 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.

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 for compensating for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending which would, in turn, impact 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 real estate 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 11 per cent per annum over the next five years. Approximately 57 per cent of Fortis Properties' operating income was derived from hotel investments in 2008 (2007 – 58 per cent). Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall 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 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 fund capital expenditures and to repay existing debt.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt 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 the finance charges of the Corporation and its utilities. Also, a significant downgrade in TGI or Terasen Inc.'s credit ratings 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 were confirmed and maintained during the fourth quarter of 2008. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current 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.

The volatility in the global financial and capital markets may increase the cost of, and affect the timing of, issuance of long-term capital by the Corporation and its utilities in 2009. While the cost of borrowing is expected to increase, as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. Due to the regulated nature of the Corporation's utilities, increased borrowing costs are eligible to be recovered in future 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. The cost of renewed and extended credit facilities may also increase going forward; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its utilities in 2009 as the majority of the total committed credit facilities have maturities beyond 2009.

Further information about 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 2008 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. Virtually all 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 warm 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 less variable climatic conditions that exist 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 new T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, including 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 to reduce price volatility and ensure, to the extent possible, that natural gas commodity 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 through the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or through 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. The Corporation and its subsidiaries do not hold or issue derivative financial instruments 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. The Corporation has also designated all of its US$403 million corporately held US dollar-denominated long-term debt 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, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged.

Interest Rate Risk: Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. Earnings of such regulated utilities are exposed to changes in long-term interest rates associated with rate-setting mechanisms. The rate of return is affected either directly through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. Automatic adjustment mechanisms currently apply to the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power. Due to a decline in long-term Canada bond yields during 2008 and the operation of the automatic adjustment mechanisms, the allowed ROEs for TGI and FortisBC have been reset for 2009. The 2008 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. Effective January 1, 2009, the allowed ROEs for TGI and FortisBC have decreased to 8.47 per cent and 8.87 per cent, respectively, while the allowed ROE for Newfoundland Power remains unchanged at 8.95 per cent. FortisAlberta is currently engaged in a Generic Cost of Capital Proceeding with its regulator to review, among other things, 2009 ROE calculations and capital structures for regulated gas, electric and pipeline utilities in Alberta. In the interim, as directed by its regulator, customer rates for 2009 for FortisAlberta have been set using the utility's 2007 allowed ROE of 8.51 per cent. The National Energy Board is also undertaking a review of existing ROE levels.

A continuation of current ROE adjustment mechanisms combined with declining long-term Canada bond yields, in an environment where the cost of capital is increasing, could materially affect the ability of the Corporation's utilities to earn reasonable ROEs, the absence of which could negatively impact the regulated utilities' financial condition, results of operations and cash flows.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest rate expense resulting from fluctuations in interest rates associated with variable rate debt 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, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt facilities 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 at December 31, 2008.

Total Debt

As at December 31, 2008	*($ millions)*	*(%)*
Short-term borrowings	**410**	**7.4**
Utilized variable-rate credit facilities classified as long-term	**224**	**4.0**
Variable-rate long-term debt and capital lease obligations (including current portion)	**22**	**0.4**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**4,878**	**88.2**
Total	**5,534**	**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. The impact of a material change in interest rates on the fair value measurement of the interest rate swaps outstanding as at December 31, 2008 is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swaps and their near-term maturities.

The nature and fair value of the interest rate swaps outstanding as at December 31, 2008 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 2008 financial results is disclosed in Note 26 to the 2008 Consolidated Financial Statements.

It is estimated that a 6 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.22, as at December 31, 2008, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2009.

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.

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 recent events in the capital markets, 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. To date, the Terasen Gas companies have not experienced any counterparty defaults and they do not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, 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: In recent years, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. 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, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and increase sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to switch to an alternative fuel. See also the "Business Risk Management – Government of British Columbia's Energy Plan" and "Business Risk Management – Risks Related to TGVI" 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 US 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 incurring costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 61 per cent of the above utilities' total employees are members of such plans. The recent volatility in the global financial and capital markets is expected to affect the Corporation's consolidated future defined benefit pension funding requirements, as discussed in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A. Future pension benefit obligations and related pension expense may also be affected. 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 pension expense. 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.

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 2008 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 pension expense.

Market-driven changes impacting the discount rate, which is used to value the accrued pension benefit obligation 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 pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, 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 pension expense at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. At the Terasen Gas companies and FortisBC, however, actual pension expense above or below the forecast pension expense 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 and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are 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 government contribution against rate base, will be required to be fully repaid. As at December 31, 2008, the balance outstanding under these loans was $61 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 progression from the previous plan with a 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. FortisBC and the Terasen Gas companies continue to assess the impacts and opportunities provided by the Energy Plan and will consider which policy actions they may support. Many of the principles of the Energy Plan were adopted when *Bill 15-2008, the Utilities Commission Amendment Act, 2008*, received Royal Assent by the Legislative Assembly of British Columbia on May 1, 2008. In addition, the *Carbon Tax Act*, which received Royal Assent by the Legislative Assembly of British Columbia on May 29, 2008, introduced a consumption tax on carbon-based fuels which impacts the competitiveness of natural gas versus non-carbon-based energy sources. The legislation did not, however, 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 recent 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 2008, 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, 2008, there were no material environmental liabilities recorded in the Corporation's 2008 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 will 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 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.

The Corporation's utilities address environmental matters in their operations through the use of Environmental Management Systems ("EMS"). As part of their respective EMS, 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 authorities to recover the loss or liability through increased customer rates. However, there can be no assurance that regulatory authorities 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' business, results of operations and financial condition. 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' business, results of operations 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.

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 that are 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 financial condition and results of operations of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices at its electricity operations has related to its non-regulated energy sales in Ontario, where energy is sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will expire on April 30, 2009 and, as a result, the Corporation's exposure to market price fluctuations in Ontario will be substantially reduced and earnings related to the Niagara Exchange Agreement will cease after that date. During 2008, earnings' contribution associated with the Niagara Exchange Agreement was approximately $16 million. 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 compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Fortis. The Corporation is currently assessing the impact a conversion to IFRS would have on its future financial reporting. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Corporation's consolidated earnings and balance sheet from that reported under Canadian GAAP. Information on the Corporation's IFRS conversion project is provided in the "Future Accounting Changes" 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 treaties or agreements, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were in Canada. Conversely, if treaties or agreements 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 the Corporation's Caribbean Regulated Electric utilities 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 a TIEA is 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.

On January 27, 2009, the Government of Canada introduced its 2009 Budget. In the budget documents, the Government of Canada indicated that it is studying the Advisory Panel's report and will provide a response in due course on which consultations will be held. The Government of Canada also indicated that it will consider the Advisory Panel's recommendations relating to foreign affiliates before proceeding with the remaining foreign affiliate measures announced in February 2004, as modified to take into account consultations and deliberations since their release.

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

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations 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 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 FortisAlberta's predecessor, 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-usage 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 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations which 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 earnings of the utilities.

The collective agreement between FortisBC and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on January 31, 2009. A new four-year collective agreement was ratified by the union in February 2009.

In September 2008, two collective agreements governing Newfoundland Power's unionized employees represented by IBEW, Local 1620, expired. In February 2009, one of the groups represented by IBEW, Local 1620, ratified a new collective agreement. This new collective agreement will be effective October 1, 2008 and will expire on September 30, 2011. The second collective agreement is subject to a conciliation process which began in March 2009.

In December 2008, the collective agreement governing Maritime Electric's unionized employees represented by IBEW, Local 1432, expired. Maritime Electric and IBEW are currently negotiating a new collective agreement.

Human Resources: The ability of Fortis to deliver superior operating performance 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 of, and impact on Fortis of, adopting the new Canadian Institute of Chartered Accountants ("CICA") accounting standards for Inventories, Capital Disclosures, and Disclosure and Presentation of Financial Instruments, effective January 1, 2008, are described in detail in Notes 5, 24, 25 and 26 to the 2008 Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the reclassification of $26 million of inventories to utility capital assets from inventories on the consolidated balance sheet as at December 31, 2007; (ii) additional disclosures about the Corporation's capital, including quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital; and (iii) additional disclosures of both qualitative and quantitative information that enable users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The adoption of the accounting standards did not have a material impact on the Corporation's 2008 Consolidated Financial Statements.

Future Accounting Changes

IFRS: In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008, the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, *Early Adoption of IFRS* which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Fortis is not planning to early adopt IFRS.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued, but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the required information.

Fortis commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the audit committees, senior management and project teams from each of the Corporation's subsidiaries. Overall project governance, management and support are coordinated by Fortis Inc. Regular reporting occurs to the Audit Committee of the Board of Directors of Fortis and of the subsidiaries, where appropriate. An external expert advisor has been engaged to assist in the IFRS conversion project.

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, has been completed. The resulting identified areas of accounting difference of highest potential impact to Fortis, based on existing IFRS, are 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 IFRS*.

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

The Corporation has completed a preliminary assessment of the impacts of adopting IFRS; however, a final assessment cannot be completed at this time pending the outcome of the project on rate-regulated activities that was recently added to the IASB's technical agenda.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. Each of the Corporation's subsidiaries is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on each of the subsidiary's information systems is not reasonably determinable at this time.

During 2008, several regulatory authorities with jurisdiction over the Corporation's regulated utilities began their own IFRS projects to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. The Corporation's regulated utilities have worked and will continue to work with their respective regulatory authorities to identify transitional issues and suggest how those issues might be addressed.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve 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 in business processes and Audit Committee approval of IFRS-compliant financial statements.

Fortis will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate.

Rate-Regulated Operations: Effective January 1, 2009, the AcSB amended: (i) CICA Handbook 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, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of 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. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of $24 million and $497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $24 million and $497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

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 1600, *Consolidated Financial Statements*, 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 to the 2008 Consolidated Financial Statements, 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*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets: Effective January 1, 2009, the Corporation will adopt 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. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities: Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. 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. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value, the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the Corporation's consolidated balance sheets approximate their fair value, 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 by 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.

An increase in credit risk and spreads as a result of the volatility experienced in the financial and capital markets has resulted in lower fair values for the Corporation's consolidated long-term debt and preference shares as at December 31, 2008 compared to December 31, 2007.

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[1]

As at December 31	2008		2007	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[1]	**5,088**	**4,927**	5,023	5,635
Preference shares, classified as debt[2]	**320**	**329**	320	346

[1] Carrying value as at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 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 of preference shares classified as equity was $268 million at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

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	2008				2007	
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 to 2	2	–	–	–	–
Foreign Exchange Forward Contract	<3	1	7	7	–	–
Natural Gas Derivatives:						
Swaps and Options	Up to 3	228	(84)	(84)	(79)	(79)
Gas Purchase Contract Premiums	Up to 3	74	(8)	(8)	5	5

The interest rate swaps are held by Fortis Properties and are designated as hedges of the cash flow risk related to floating-rate long-term debt and mature in July 2009 and October 2010. The effective portion of changes in the fair value of the interest rate swaps at Fortis Properties is recorded in other comprehensive income. During 2008, the interest rate swaps of the Terasen Gas companies matured.

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US$55 million required to be paid under a contract for the construction of an LNG storage facility.

The natural gas derivatives 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. At the Terasen Gas companies, changes in the fair value of interest rate swaps, 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 values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – accounts payable and accounts receivable).

The interest rate swaps are 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 future cash flows based on published forward future foreign exchange market rate curves. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts 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 authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues 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, 2008, Fortis recorded $360 million in current and long-term regulatory assets (December 31, 2007 – $312 million) and $446 million in current and long-term regulatory liabilities (December 31, 2007 – $392 million). The increase in regulatory assets year over year was primarily due to amounts deferred in FortisAlberta's AESO charges deferral account in 2008 and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase in regulatory liabilities year over year was largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2008 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, 2008, the Corporation's consolidated utility capital assets and income producing properties were approximately $7.9 billion, or approximately 71 per cent of total consolidated assets, compared to consolidated utility capital assets and income producing properties of $7.3 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2007. The increase in capital assets was primarily associated with capital expenditures, which totalled $904 million in 2008. Amortization expense for 2008 was $348 million compared to $273 million for 2007. 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 authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, 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 at December 31, 2008 was $337 million (December 31, 2007 – $319 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2008 was $35 million (2007 – $33 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. Changes in regulator-approved amortization rates at FortisAlberta and Newfoundland Power during 2008 did not have a material impact on consolidated amortization expense.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing in May 2008, Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over 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 regulators. In 2008, GEC totalled $57 million (2007 – $42 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.

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. In July of each year, the Corporation reviews for impairment of goodwill and updates its review as at year end. 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 $1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2008. For a discussion of the nature of the change in goodwill during 2008, refer to the "Consolidated Financial Position" section of this MD&A.

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 expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued pension 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 pension expense for 2009, range from 6.75 per cent to 7.25 per cent for the larger defined benefit pension plans. These rates compare to assumed long-term rates of return used in 2008 that ranged from 6.50 per cent to 7.50 per cent. The defined benefit pension plan assets experienced total negative returns during 2008 of approximately $92 million compared to expected positive returns of $49 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 2008 and to determine pension expense for 2009 ranged from 6.00 per cent to 7.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2007 and determine pension expense for 2008 that ranged from 5.25 per cent to 5.60 per cent. The discount rates increased as a result of the impact of increased credit risk spreads on investment-grade corporate bonds due to volatility in the capital markets. 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.

As the measurement date for FortisAlberta, FortisBC and FortisOntario's defined benefit pension plans is September 30, 2008, the further impact on credit risk spreads of capital market volatility that continued through the remainder of 2008 was not reflected in the discount rates assumed by these utilities as at September 30, 2008, nor was the further erosion of capital market value reflected in the fair value of the pension plan assets measured as at September 30, 2008.

Fortis expects no material increase in its consolidated pension expense for 2009 related to its defined benefit pension plans. The amortization of 2008 losses associated with the pension plan assets is expected to be largely offset by the impact of higher assumed discount rates. The impact of the decline in pension plan assets in 2008, as it relates to 2009 pension expense, is being mitigated by the use of the market-value related method for valuing pension assets at the Terasen Gas companies and Newfoundland Power.

Consolidated defined benefit pension expense and pension funding obligations for 2009 may be affected, however, by the outcome of December 31, 2008 actuarial valuations which, for Newfoundland Power, the Corporation and for one of the defined benefit pension plans at Terasen, are expected to be completed in 2009.

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 2008 net defined benefit pension expense, 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, 2008

Increase (decrease)	Net benefit expense		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	–	(3)	(1)	3	(1)	–	(19)	(38)
Impact of decreasing the discount rate assumption by 100 basis points	4	6	(3)	(5)	1	–	21	46

Other assumptions applied in measuring defined benefit pension expense 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 expense 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 expense and obligations.

As approved by the respective regulators, 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 expense 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 and FortisBC have regulator-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or regulatory liability.

As at December 31, 2008, the Corporation had a consolidated accrued benefit asset of $133 million (December 31, 2007 – $120 million) and a consolidated accrued benefit liability of $168 million (December 31, 2007 – $150 million). During 2008, the Corporation recorded consolidated net benefit expense of $27 million (2007 – $26 million).

Asset-Retirement Obligations: The measurement of 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, 2008 and 2007. 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 authorities. 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, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $365 million (December 31, 2007 – $309 million) on annual consolidated revenue of approximately $3.9 billion (2007 – $2.7 billion).

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course 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. The matter is currently under appeal to the Supreme Court of British Columbia.

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

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the 2008 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 a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2008 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 the Point Lepreau Nuclear Generating Station 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. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, 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.

FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately $9 million (US$7 million). There was no impact on the 2008 Consolidated Financial Statements as a result of the settlement of these legal proceedings.

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a $61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with Exploits Partnership's lenders with respect to the above 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-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been reclassified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2008, 2007 and 2006. 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, revenues 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)*	**2008**	2007[(1)]	2006
Revenue and equity income	**3,903**	2,718	1,472
Net earnings	**259**	199	149
Net earnings applicable to common shares	**245**	193	147
Total assets	**11,178**	10,273	5,441
Long-term debt and capital lease obligations (net of current portion)	**4,884**	4,623	2,558
Preference shares[(2)(3)]	**667**	442	442
Common shareholders' equity	**3,046**	2,601	1,276
Basic earnings per common share	**1.56**	1.40	1.42
Diluted earnings per common share	**1.52**	1.32	1.37
Dividends declared per common share	**1.01**	0.88	0.70
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[(4)]	**1.2250**	1.2250	0.5211
Dividends declared per First Preference Share, Series G[(3)]	**1.0184**	–	–

(1) Financial results for 2007 were significantly impacted by the acquisition of Terasen on May 17, 2007.

(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 are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum.

(4) 5 million First Preference Shares, Series F were issued on September 28, 2006 at $25.00 per share for net after-tax proceeds of $122 million and are entitled to receive cumulative dividends in the amount of $1.2250 per share per annum.

2008/2007 – Revenue increased 43.6 per cent over 2007. The increase was driven by contributions 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 26.9 per cent over 2007. The increase in earnings was primarily due to earnings' contributions 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 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 11.4 per cent from 2007, primarily due to growth in earnings.

2007/2006 – Revenue, including equity income, increased 84.6 per cent over 2006. The increase was driven by contributions from the Terasen Gas companies, from the date of acquisition, and the impact of consolidating the Corporation's approximate 54 per cent controlling ownership in Caribbean Utilities during 2007 compared to recording the Corporation's 37 per cent interest in Caribbean Utilities during 2006 on an equity basis. Net earnings applicable to common shares grew 31.3 per cent over 2006, attributable to the acquisition of Terasen in May 2007, the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. The growth in total assets and increase in long-term debt in 2007 was driven by assets acquired and debt assumed upon the acquisition of Terasen in May 2007. The remaining increase in assets and long-term debt was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta and FortisBC and the acquisition of the Delta Regina, partially offset by the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. Common shareholders' equity more than doubled during 2007, driven by the issuance of approximately $1.15 billion in common equity required to fund a significant portion of the net cash purchase price of Terasen. Basic earnings per common share decreased 1.4 per cent from 2006. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and seasonality of earnings at the Terasen Gas companies.

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2008 and 2007. 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 2008 is also contained in the Corporation's fourth quarter 2008 media release, dated and filed on SEDAR at www.sedar.com on February 5, 2009, 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)*		
	2008	2007	Variance	**2008**	2007	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
Terasen Gas Companies	**66,816**	69,108	(2,292)	**606**	548	58
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,068**	4,002	66	**78**	68	10
FortisBC	**842**	839	3	**66**	61	5
Newfoundland Power	**1,412**	1,384	28	**139**	132	7
Other Canadian	**543**	554	(11)	**65**	66	(1)
	6,865	6,779	86	**348**	327	21
Regulated Electric Utilities – Caribbean *(GWh)*	**361**	272	89	**159**	76	83
Non-Regulated – Fortis Generation *(GWh)*	**312**	303	9	**20**	19	1
Non-Regulated – Fortis Properties				**52**	50	2
Corporate and Other				**7**	6	1
Inter-Segment Eliminations				**(10)**	(8)	(2)
Total				**1,182**	1,018	164

Gas Volumes: Gas volumes at the Terasen Gas companies decreased quarter over quarter, primarily due to lower transportation volumes to customers sourcing their own gas supplies, partially offset by higher sales volumes to residential customers as a result of increased consumption due to cooler weather compared to the same period for the previous year.

Energy and Electricity Sales: Increased energy and electricity sales at the Corporation's regulated electric utilities quarter over quarter were driven by: (i) two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end; (ii) an increase at FortisAlberta mainly due to customer growth; and (iii) an increase at Newfoundland Power primarily due to the combined impact of customer growth and higher average consumption. The increases were partially offset by decreased sales at Other Canadian Electric Utilities, driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

The increase in energy sales at Non-Regulated – Fortis Generation was mainly due to higher production in central Newfoundland and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue for the fourth quarter of 2008 was $164 million higher than the same quarter in 2007. The increase was driven by the Terasen Gas companies and the Corporation's Regulated Electric Utilities. Revenue at the Terasen Gas companies increased quarter over quarter mainly due to higher commodity cost of gas charged to customers, increased residential consumption and an increase in customer gas distribution rates effective January 1, 2008, reflecting a higher allowed ROE for 2008. Increased revenue at Regulated Electric Utilities – Canadian quarter over quarter was mainly due to customer rate increases, which included the impact of higher allowed ROEs for 2008 and customer growth. Revenue at Regulated Electric Utilities – Caribbean increased quarter over quarter primarily due to two additional months of revenue contribution from Caribbean Utilities, an approximate $30 million favourable impact of foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the Canadian dollar against the US dollar quarter over quarter, and the flow through to customers of higher energy supply costs.

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	2008	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	**47**	52	(5)
Regulated Electric Utilities – Canadian			
FortisAlberta	**11**	6	5
FortisBC	**7**	7	–
Newfoundland Power	**8**	9	(1)
Other Canadian	**3**	3	–
	29	25	4
Regulated Electric Utilities – Caribbean	**8**	9	(1)
Non-Regulated – Fortis Generation	**8**	7	1
Non-Regulated – Fortis Properties	**4**	8	(4)
Corporate and Other	**(20)**	(22)	2
Net Earnings Applicable to Common Shares	**76**	79	(3)

Earnings: Earnings for the fourth quarter of 2008 were $76 million or $3 million lower than $79 million for the same quarter in 2007. Fourth quarter results for 2007 were favourably impacted by one-time items totalling approximately $13 million related to: (i) the sale of surplus land at TGI; (ii) the reduction of future income tax liability balances at Fortis Properties related to lower enacted corporate income tax rates; and (iii) an interconnection agreement-related refund at FortisOntario. Excluding these one-time items, earnings were $10 million higher quarter over quarter. The increase was driven by stronger performance and lower corporate taxes at FortisAlberta, lower corporate expenses and $1 million of additional earnings from Caribbean Utilities related to a change in the utility's fiscal year end. The increase was partially offset by the impact of: (i) a lower allowed ROA at Belize Electricity, effective July 1, 2008; (ii) an approximate $1 million loss of revenue at Fortis Turks and Caicos related to Hurricane Ike; and (iii) an approximate $2 million reduction in fourth quarter 2008 earnings at Newfoundland Power associated with a shift in the quarterly distribution of the utility's annual purchased power expense. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense.

Summary of Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	2008	2007	Variance
Cash, Beginning of Period	**68**	51	17
Cash Provided By (Used In)			
Operating Activities	**214**	152	62
Investing Activities	**(277)**	(234)	(43)
Financing Activities	**58**	89	(31)
Foreign Currency Impact on Cash Balances	**3**	–	3
Cash, End of Period	**66**	58	8

Cash flow provided from operating activities, after working capital adjustments, increased $62 million quarter over quarter. The increase was mainly due to favourable working capital changes at the Terasen Gas companies related to the impact of cooler weather and higher commodity natural gas costs charged to customers during the fourth quarter of 2008 compared to the fourth quarter of 2007. The increase was partially offset by lower cash from operating activities at FortisAlberta. However, during the fourth quarter of 2007, FortisAlberta received cash from the sale of amounts in its 2007 AESO charges deferral account.

Cash used in investing activities increased $43 million quarter over quarter, reflecting higher utility capital expenditures and the acquisition of the Fairmount Newfoundland hotel in November 2008.

Cash provided from financing activities was $31 million lower quarter over quarter. Increased cash associated with the $300 million common share issue in the fourth quarter of 2008 was more than offset by the impact of a net decrease in debt during the fourth quarter of 2008 compared to a net increase in debt during the same quarter for the previous year.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2007 through December 31, 2008. 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, revenues 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 Applicable to Common Shares *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2008	1,182	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
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. Financial results for the fourth quarter of 2008 include two additional months of contribution from Caribbean Utilities resulting from a change in the utility's fiscal year end. Financial results from May 17, 2007 were impacted by the acquisition of Terasen.

Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results for the second quarter of 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. Due to a shift in the quarterly distribution of annual purchased power expense at Newfoundland Power, the Company's earnings in 2008 were lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense. Financial results from August 1, 2007 were impacted by the acquisition of the Delta Regina in Saskatchewan.

December 2008/December 2007 – Net earnings applicable to common shares were $76 million, or $0.48 per common share, for the fourth quarter of 2008, compared to earnings of $79 million, or $0.51 per common share, for the fourth quarter of 2007. A discussion on the variances between the financial results for the fourth quarter of 2008 and the fourth quarter of 2007 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2008/September 2007 – Net earnings applicable to common shares were $49 million, or $0.31 per common share, for the third quarter of 2008 compared to earnings of $31 million, or $0.20 per common share, for the third quarter of 2007. Third quarter 2008 results included a tax reduction of approximately $7.5 million associated with the settlement of historical corporate tax matters at Terasen. Excluding the tax reduction at Terasen, earnings for the third quarter of 2008 were $41.5 million or $0.26 per common share. Excluding the above one-time item, growth in earnings quarter over quarter was mainly due to higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, higher non-regulated hydroelectric production, increased earnings at FortisBC primarily due to lower energy supply costs and higher earnings at FortisAlberta mainly due to higher corporate tax recoveries. The increase was partially offset by lower earnings at Caribbean Regulated Utilities driven by a 3.25 per cent reduction in basic electricity rates at Caribbean Utilities, a lower allowed ROA at Belize Electricity and a loss of revenue at Fortis Turks and Caicos due to the impact of Hurricane Ike.

June 2008/June 2007 – Net earnings applicable to common shares were $29 million, or $0.19 per common share, for the second quarter of 2008 compared to earnings of $41 million, or $0.31 per common share, for the second quarter of 2007. Second quarter 2008 results included a $13 million, or $0.08 per common share, charge representing the Corporation's approximate 70 per cent share of disallowed previously incurred fuel and purchased power costs at Belize Electricity as well as a $2 million one-time charge at FortisOntario associated with repayment of interconnection-agreement related amounts received in the fourth quarter of 2007. Excluding the above one-time items, earnings for the second quarter of 2008 were $44 million compared to $41 million for the second quarter of 2007. Earnings were favourably impacted by a full quarter of earnings' contribution from the Terasen Gas companies, higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, increased non-regulated hydroelectric production and improved performance at Fortis Properties. Partially offsetting those items were lower earnings at FortisAlberta associated with higher corporate income taxes and higher corporate financing costs associated with the Terasen acquisition.

March 2008/March 2007 – Net earnings applicable to common shares were $91 million, or $0.58 per common share, for the first quarter of 2008, up $49 million from earnings of $42 million, or $0.38 per common share, for the first quarter of 2007. Growth in earnings was primarily attributable to the contribution from the Terasen Gas companies, acquired on May 17, 2007, and also reflected improved performance at Caribbean Utilities. The growth was partially offset by higher corporate financing costs associated with the Terasen acquisition and lower earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense. Earnings' contribution from Caribbean Utilities during the first quarter of 2007 was reduced by $2 million associated with a one-time charge on the disposal of steam-turbine assets.

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 maintained 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, 2008 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 the 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, 2008 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2008, 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 Events

In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

Outlook

Gross consolidated capital expenditures are estimated to be approximately $1 billion in 2009 and approximately $4.5 billion over the next five years. The Corporation's capital program should drive growth in earnings and dividends.

With its substantial credit facilities and conservative capital structure, Fortis believes it has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009. The Corporation and its utilities also expect to continue to have reasonable access to long-term capital in 2009.

The Corporation continues to pursue acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States 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 10, 2009, the Corporation had issued and outstanding 169.8 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; and 9.2 million First Preference Shares, Series G. 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 10, 2009 is as follows:

Conversion of Securities into Common Shares

As at March 10, 2009 *(Unaudited)*

Security	Number of Common Shares *(millions)*
Stock Options	4.1
Convertible Debt	1.8
First Preference Shares, Series C	6.0
First Preference Shares, Series E	9.7
Total	**21.6**

Additional information, including the Fortis 2008 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

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2008 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including 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 2008 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 the 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 the shareholders' auditors' independence and auditors' fees. The 2008 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2008 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 the recommendation of the Audit Committee, have performed an audit of the 2008 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer
St. John's, Canada

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

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2008 and 2007 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these 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, 2008 and 2007 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,
January 30, 2009

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	2008	2007
Current assets		
Cash and cash equivalents	$ 66	$ 58
Accounts receivable	681	635
Prepaid expenses	17	19
Regulatory assets *(Note 4)*	157	119
Inventories *(Note 5)*	229	207
	1,150	1,038
Deferred charges and other assets *(Note 6)*	279	179
Regulatory assets *(Note 4)*	203	193
Future income taxes *(Note 19)*	54	37
Utility capital assets *(Note 7)*	7,367	6,748
Income producing properties *(Note 8)*	541	519
Intangibles, net of amortization *(Note 2)*	9	15
Goodwill *(Note 9)*	1,575	1,544
	$ 11,178	$ 10,273
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 26)*	$ 410	$ 475
Accounts payable and accrued charges	874	793
Dividends payable	47	43
Income taxes payable	66	30
Regulatory liabilities *(Note 4)*	45	20
Current installments of long-term debt and capital lease obligations *(Note 10)*	240	436
Future income taxes *(Note 19)*	15	7
	1,697	1,804
Deferred credits *(Note 11)*	277	261
Regulatory liabilities *(Note 4)*	401	372
Future income taxes *(Note 19)*	61	55
Long-term debt and capital lease obligations *(Note 10)*	4,884	4,623
Non-controlling interest *(Note 12)*	145	115
Preference shares *(Note 13)*	320	320
	7,785	7,550
Shareholders' equity		
Common shares *(Note 14)*	2,449	2,126
Preference shares *(Note 13)*	347	122
Contributed surplus	9	6
Equity portion of convertible debentures *(Note 10)*	6	6
Accumulated other comprehensive loss *(Note 16)*	(52)	(88)
Retained earnings	634	551
	3,393	2,723
	$ 11,178	$ 10,273

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)	2008	2007
Revenue	$ 3,903	$ 2,718
Expenses		
Energy supply costs	2,112	1,287
Operating	743	617
Amortization	348	273
	3,203	2,177
Operating Income	700	541
Finance charges *(Note 17)*	363	299
Gain on sale of property *(Note 18)*	–	(8)
	363	291
Earnings Before Corporate Taxes and Non-Controlling Interest	337	250
Corporate taxes *(Note 19)*	65	36
Net Earnings Before Non-Controlling Interest	272	214
Non-controlling interest	13	15
Net Earnings	259	199
Preference share dividends	14	6
Net Earnings Applicable to Common Shares	$ 245	$ 193
Earnings Per Common Share *(Note 14)*		
Basic	$ 1.56	$ 1.40
Diluted	$ 1.52	$ 1.32

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)	2008	2007
Balance at Beginning of Year	$ 551	$ 486
Net Earnings Applicable to Common Shares	245	193
	796	679
Dividends on Common Shares	(162)	(128)
Balance at End of Year	$ 634	$ 551

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)	2008	2007
Net Earnings	$ 259	$ 199
Unrealized foreign currency translation gains (losses) on net investments in self-sustaining foreign operations	115	(70)
(Losses) gains on hedges of net investments in self-sustaining foreign operations	(92)	48
Corporate tax recovery (expense)	13	(9)
Change in Unrealized Foreign Currency Translation Gains (Losses), Net of Hedging Activities and Tax *(Note 16)*	36	(31)
Comprehensive Income	$ 295	$ 168

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)	2008	2007
Operating Activities		
Net earnings	$ 259	$ 199
Items not Affecting Cash		
Amortization – utility capital assets and income producing properties	339	261
Amortization – intangibles and other	9	12
Future income taxes *(Note 19)*	14	–
Non-controlling interest	13	15
Write-down of deferred power costs – Belize Electricity *(Note 4)*	18	–
Gain on sale of property *(Note 18)*	–	(8)
Other	(7)	–
Change in long-term regulatory assets and liabilities	(23)	11
	622	490
Change in non-cash operating working capital	41	(117)
	663	373
Investing Activities		
Change in deferred charges, other assets and deferred credits	(31)	(4)
Utility capital expenditures	(890)	(790)
Contributions in aid of construction	85	73
Income producing property capital expenditures	(14)	(13)
Proceeds on sale of capital assets	18	4
Business acquisitions, net of cash acquired *(Note 21)*	(22)	(1,303)
	(854)	(2,033)
Financing Activities		
Change in short-term borrowings	(69)	103
Proceeds from long-term debt, net of issue costs	662	797
Repayments of long-term debt and capital lease obligations	(431)	(363)
Net (repayments) borrowings under committed credit facilities	(309)	25
Advances from (to) non-controlling interest	3	(3)
Issue of common shares, net of costs	308	1,267
Issue of preference shares, net of costs	223	–
Dividends		
Common shares	(162)	(128)
Preference shares	(14)	(6)
Subsidiary dividends paid to non-controlling interest	(15)	(12)
	196	1,680
Effect of exchange rate changes on cash and cash equivalents	3	(3)
Change in Cash and Cash Equivalents	8	17
Cash and Cash Equivalents, Beginning of Year	58	41
Cash and Cash Equivalents, End of Year	$ 66	$ 58

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

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

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, and commercial real estate 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"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

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 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 propane distribution system in Whistler, British Columbia, providing service to mainly 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 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant 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 and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012.

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 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). 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. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. The impact on 2008 earnings was not material. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' 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 on the Turks and Caicos Islands. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. 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 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

c. *Central Newfoundland*: Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement expiring in 2033 (Note 28).

d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This 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 US 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 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate 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. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; 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. While currently not significant, 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", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

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 both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. 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").

Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGVI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGVI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGVI have been extended until 2009. During 2008, the BCUC extended the PBR agreement for FortisBC for the years 2009 through 2011. Under the PBR agreement, 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 8.62 per cent for 2008 (2007 – 8.37 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.32 per cent for 2008 (2007 – 9.07 per cent) on a deemed capital structure of 40 per cent common equity. FortisBC's allowed ROE was 9.02 per cent for 2008 (2007 – 8.77 per cent) on a deemed capital structure of 40 per cent common equity. The allowed ROE at each of TGI, TGVI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. 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.

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 8.75 per cent for 2008 (2007 – 8.51 per cent) on a deemed capital structure of 37 per cent common equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. 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.

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. Between test years, Newfoundland Power's allowed ROE is adjusted annually 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 2008 was 8.95 per cent (2007 – 8.60 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 traditional 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 10.00 per cent for 2008 (2007 – 10.25 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 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 operates 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. In 2008, the utility's electricity distribution rates were based upon costs derived from a 2004 test year using a deemed capital structure of 46.7 per cent common equity. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure over a three-year period. FortisOntario's allowed ROE was 9 per cent for 2008 (2007 – 9 per cent).

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 licences' conditions. The basic electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and an allowed rate of return on rate base assets ("ROA"). Belize Electricity's allowed ROA was set at 10.00 per cent effective July 1, 2008 (2007 – 10.00 to 15.00 per cent).

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 (the "Government") since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive transmission and distribution ("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 new licences establish a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates are set using an initial targeted allowed ROA of 10 per cent, down from an allowed ROA of 15 per cent that was permitted under the previous licence. The new licences detail the role of the Electric Regulatory Authority, which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve 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 October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these 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 17.5 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 Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

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

Regulation (cont'd)

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 shortfalls. The submissions for 2008 calculated the Allowable Operating Profit for 2008 to be $22 million (US$18 million) and the cumulative shortfall at December 31, 2008 to be $22 million (US$18 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 shortfalls. 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.

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 agreements dated November 29, 1986 and October 8, 1987 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 regulators, amortization expense at FortisAlberta, FortisBC, 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. At December 31, 2008, the long-term regulatory liability for future asset removal and site restoration costs was $337 million (December 31, 2007 – $319 million) (Note 4 *(xii)*). The Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future asset removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2008. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings when incurred, and these costs did not have a material impact on the Corporation's 2008 and 2007 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 regulators, 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 and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2008 was approximately $31 million (2007 – $26 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 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 regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity 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 regulators. 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 2008, GEC totalled $57 million (2007 – $42 million).

As required by their respective regulators, 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") that 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 2008 was $13 million (2007 – $8 million) (Note 17), including an equity component of $6 million (2007 – $3 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 2008, amortization expense was reduced by $4 million (2007 – $5 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 39.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2008 was 3.5 per cent (2007 – 3.6 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.

	2008		2007	
	Service Life Ranges (Years)	**Average Remaining Service Life (Years)**	Service Life Ranges (Years)	Average Remaining Service Life (Years)
Distribution				
Gas	**10–100**	**35**	10–100	33
Electricity	**5–75**	**28**	10–75	28
Transmission				
Gas	**10–50**	**37**	10–50	38
Electricity	**10–75**	**35**	10–75	34
Generation	**5–75**	**29**	5–75	32
Other	**5–67**	**14**	5–67	14

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 which 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.

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

Intangibles

Intangibles include the estimated fair value of water rights associated with the Rankine hydroelectric generating station in Ontario and intangibles associated with the acquisition of Terasen. The Rankine water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. As at April 30, 2009, in accordance with the Niagara Exchange Agreement, the Corporation's water entitlement on the Niagara River associated with the Rankine hydroelectric generating station will expire and associated earnings' contribution will cease.

Upon the acquisition of Terasen, $10 million was assigned as the value associated with customer contracts at CWLP. The intangible is being amortized using the straight-line method over the remaining term of the contracts to December 31, 2011. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

As at December 31, 2008, the net book value of intangibles was $9 million (net of accumulated amortization of $28 million) (December 31, 2007 – $15 million (net of accumulated amortization of $21 million)).

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and deferred charges and other assets when events or changes in circumstances may 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, 2008 and 2007.

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 return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authorities. 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. 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. No goodwill impairment provision has been determined for the years ended December 31, 2008 and 2007.

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 costs 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 applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. 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 the expense 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 *(viii)* and *(xvii)*).

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, 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 costs 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 regulators, the costs of OPEB plans at FortisAlberta and Newfoundland Power are recovered in customer rates based on the cash payments made, with the exception of retirement allowances arising from Newfoundland Power's 2005 Early Retirement Program. The cost of supplemental pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made.

Any difference between the expense 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 *(iv)*).

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 15). 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.

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.

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

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 dates. 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 at December 31, 2008 was US$1.00 = CDN$1.22 (December 31, 2007 – 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 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 on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated at the exchange rate prevailing on the transaction date. Gains and losses on translation are included 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 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 *(xvi)*). Currently, 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 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 an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

Effective January 1, 2008, the Corporation has 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 new disclosures are provided in Notes 25 and 26.

Hedging Relationships

At December 31, 2008, the Corporation's hedging relationships consisted of interest rate swap 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.

Fortis Properties has designated its interest rate swap contracts as hedges of the cash flow risk related to floating-rate long-term debt. The interest rate swap contracts are 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 interest rate swap contracts that are in effective hedging relationships are recorded in other comprehensive income.

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US$55 million required to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The foreign exchange forward contract is valued at the present value of future cash flows based on published forward future foreign exchange market rate curves. 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 values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, that the Corporation would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date. As at December 31, 2008, 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

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, 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.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the cash taxes payable method of accounting for income taxes, as prescribed by their respective regulators. Under this methodology, except for certain deferred accounts specifically prescribed by the respective regulators, current customer rates do not include the recovery of future income taxes related to certain 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.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. In the absence of rate regulation, future income tax assets and liabilities would have been recorded and the Corporation's future income tax liabilities and future income tax assets would have increased by approximately $364 million and $18 million, respectively, as at December 31, 2008 (December 31, 2007 – $344 million and $29 million, respectively).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. 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 term of the 50-year power purchase agreement.

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.

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

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 authorities 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 authorities, 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 the 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 rendered 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 balance sheet as a regulatory liability (Note 4 *(xiii)*).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. At the Corporation's other regulated utilities, transmission revenue and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with 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 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 collected, or refunded, in future customer rates (Note 4 *(iii)*).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara 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 are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these 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 stations 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 a 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 transmission and distribution 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 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 new 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.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft. Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required, as well as system changes that may be necessary to gather and process the information.

3. Future Accounting Changes (cont'd)

Rate-Regulated Operations

Effective January 1, 2009, the AcSB amended: (i) CICA Handbook 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, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of 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. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of $24 million and $497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $24 million and $497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

Effective January 1, 2009, with the removal of the temporary exemption from Section 1100, the Corporation must now apply Section 1100 for 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 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. All assets and liabilities arising from rate regulation 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*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption from Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation will adopt 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. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. 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. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value (Note 25), the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

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 revenues 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 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)*	**2008**	2007	**Remaining recovery period (Years)**
Rate stabilization accounts – Terasen Gas companies *(i)*	**$ 76**	$ 99	1–3
Rate stabilization accounts – electric utilities *(ii)*	**78**	66	Various
AESO charges deferral *(iii)*	**64**	8	2
Regulatory OPEB plan asset *(iv)*	**51**	44	Indeterminable
Income taxes recoverable on OPEB plans *(v)*	**18**	16	Indeterminable
Deferred capital asset amortization *(vi)*	**8**	12	1–2
Residential unbundling *(vii)*	**7**	9	1–3
Deferred pension costs *(viii)*	**7**	8	7
Southern Crossing Pipeline tax reassessment *(ix)*	**7**	7	Indeterminable
Energy management costs *(x)*	**7**	6	1–8
Other regulatory assets *(xi)*	**37**	37	Indeterminable
Total regulatory assets	**360**	312	
Less: current portion	**(157)**	(119)	1
Long-term regulatory assets	**$ 203**	$ 193	

Regulatory Liabilities *(in millions)*	**2008**	2007	**Remaining settlement period (Years)**
Future asset removal and site restoration provision *(xii)*	**$ 337**	$ 319	Indeterminable
Rate stabilization accounts – Terasen Gas companies *(i)*	**32**	–	1–3
Rate stabilization accounts – electric utilities *(ii)*	**9**	–	1
Unbilled revenue liability *(xiii)*	**15**	22	Indeterminable
PBR incentive liabilities *(xiv)*	**13**	14	1
Southern Crossing Pipeline deferral *(xv)*	**9**	5	1–5
Fair value of the foreign exchange forward contract *(xvi)*	**7**	–	Indeterminable
Pension deferral *(xvii)*	**4**	6	1–5
Other regulatory liabilities *(xviii)*	**20**	26	Indeterminable
Total regulatory liabilities	**446**	392	
Less: current portion	**(45)**	(20)	1
Long-term regulatory liabilities	**$ 401**	$ 372	

Description of the Nature of Regulatory Assets and Liabilities

(i) *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.

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

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

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 swaps.

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 the fair value of TGVI's natural gas commodity swaps. 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 2008 and 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be refunded through rates over a three-year period, with a total balance outstanding as at December 31, 2008 of $8 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered, or refunded, 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 amounts in the rate stabilization accounts is dependent on actual natural gas consumption volumes and on annually approved customer rates.

As at December 31, 2008, the balances in the RSAM and MCRA were in a payable position, as compared to a receivable position as at December 31, 2007.

(ii) Rate Stabilization Accounts – Electric Utilities

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered, or refunded, through customer rates as approved by the respective regulatory authorities. 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. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, whose recovery period is not determinable, ranges from one year to five years and is subject to periodic review by the respective regulators.

As at December 31, 2008, the balance in Belize Electricity's rate stabilization account was in a payable position, as compared to a receivable position as at December 31, 2007. During the second quarter of 2008, a downward $18 million adjustment was made to Belize Electricity's cost of power 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.

The balance in Newfoundland Power's weather normalization account 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 in the period in which they occurred. The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

As at December 31, 2008, $12 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 six years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling eight-month period.

In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed as incurred.

(iii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral to be collected in future customer rates. As at December 31, 2008, the balance of the AESO charges deferral account, comprised of the 2008 AESO charges deferral balance of $57 million and the unsold portion of the 2007 AESO charges deferral balance, is expected to be collected in customer rates in 2010 and 2009, respectively. In the absence of rate regulation, the costs would be expensed as incurred and no deferral treatment would be permitted.

During 2007, FortisAlberta sold approximately $28 million and $38 million of the 2006 and 2007 AESO charges deferral accounts, respectively, to a Canadian chartered bank for proceeds of approximately $28 million and $38 million, respectively. Proceeds included cash consideration of $64 million and receivables of approximately $2 million due in February 2009 and 2010.

(iv) *Regulatory OPEB Plan Asset*
At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by the respective regulators. 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 OPEB plans. The regulatory OPEB asset represents the deferred portion of the benefit expense 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 expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta's and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(v) *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. Since TGI accounts for income taxes using the cash taxes payable method, 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.

(vi) *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 approximate $12 million balance at December 31, 2007 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.

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

(viii) *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.

(ix) *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. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to $7 million and the overpayment was refunded to TGI. 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).

(x) *Energy Management Costs*
FortisBC provides energy management services to promote energy efficiency programs to its customers. As required by a BCUC order, the Company has capitalized related expenditures and is amortizing these expenditures on a straight-line basis over eight 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.

(xi) *Other Regulatory Assets*
Other regulatory assets primarily 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, 2008, $32 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, 2008, $7 million (December 31, 2007 – $9 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

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

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

(xii) Future Asset Removal and Site Restoration Provision

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, 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 regulators, amortization rates at FortisAlberta, FortisBC, 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 regulators. 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 2008, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was $35 million (2007 – $33 million). During 2008, actual asset removal and site restoration costs, net of salvage proceeds, were $21 million (2007 – $19 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.

(xiii) 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 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 the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $7 million of this regulatory liability in 2008 (2007 – $3 million). The remaining balance as at December 31, 2008 will be amortized by approximately $5 million in each of 2009 and 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 $6 million as at December 31, 2008 (December 31, 2007 – $5 million) is not subject to a regulatory return.

(xiv) 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 by the sharing mechanisms with customers as approved per BCUC orders (Note 2). TGI's regulatory PBR incentive liability of $11 million is expected to be refunded to customers through reduced rates in 2009. Based on the current PBR framework, FortisBC's 2008 regulatory PBR incentive liability of $2 million has been approved by the BCUC for settlement in 2009 through a reduction in 2009 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xv) 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 balance is amortized over five years. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xvi) 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. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings. This regulatory deferral is not subject to a regulatory return.

(xvii) Pension Deferral

This regulatory liability represents pension surplus at FortisAlberta that has not been reflected in customer rates and will result in a reduction in future customer rates when recognized. When future customer rates are reduced, this liability will be drawn down and reflected as a reduction of pension expense. In the absence of rate regulation, the pension deferral would not be permitted and the amortization of the liability would not have occurred. This regulatory pension deferral is not subject to a regulatory return.

(xviii) Other Regulatory Liabilities

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2008, $17 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, 2008, $2 million (December 31, 2007 – $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:

(in millions)	**2008**	2007
Decrease in regulatory assets	**$ (349)**	$ (303)
Decrease in regulatory liabilities	**(446)**	(392)
Decrease in accumulated other comprehensive loss	**(18)**	(48)
Decrease in opening retained earnings	**(61)**	(60)
Increase in revenue	**$ 582**	$ 343
Increase in energy supply costs	**540**	340
Increase in operating expense	**79**	62
Decrease in amortization expense	**(39)**	(28)
Increase in finance charges	**–**	3
Decrease in corporate taxes	**(16)**	(15)
Net increase (decrease) in earnings	**$ 18**	$ (19)

5. Inventories

(in millions)	**2008**	2007
Gas in storage	**$ 212**	$ 195
Materials and supplies	**17**	12
	$ 229	$ 207

During 2008, inventories of $1,268 million (2007 – $559 million) were expensed and reported in energy supply costs in the consolidated statement of earnings. Inventories expensed to operating expenses were $14 million for 2008 (2007 – $13 million), which included $9 million for food and beverage costs at Fortis Properties (2007 – $8 million).

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031, *Inventories* and inventories of $26 million were reclassified to utility capital assets from inventories on the balance sheet, as they were held for the development, construction and maintenance of other utility capital assets (January 1, 2007 – $18 million).

6. Deferred Charges and Other Assets

(in millions)	**2008**	2007
Deferred pension costs *(Note 20)*	**$ 128**	$ 114
Exploits Partnership hydroelectric generating facility capital assets *(Note 28)*	**61**	–
AESO contributions	**48**	19
Long-term accounts receivable (due 2040)	**9**	7
Deferred recoverable and project costs	**8**	7
Energy management loans	**6**	6
Corporate income tax deposit at Maritime Electric *(Note 28)*	**6**	6
Other deferred charges and assets	**13**	20
	$ 279	$ 179

6. *Deferred Charges and Other Assets (cont'd)*

As at December 31, 2008, the Exploits Partnership hydroelectric generating facility capital assets and deferred financing costs were reclassified to deferred charges and other assets from utility capital assets and long-term debt, respectively, as further discussed in Note 28.

AESO contributions represent payments to AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through an AUC-approved amortization rate of approximately 3.8 per cent.

Deferred recoverable costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties.

Energy management loans are 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.

Other deferred charges and assets are recorded at cost and are recovered or amortized over the estimated period of future benefit.

7. Utility Capital Assets

2008

(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,426	$ (495)	$ (180)	$ –	$ 1,751
Electricity	3,948	(1,042)	(490)	(87)	2,329
Transmission					
Gas	1,304	(316)	(100)	–	888
Electricity	970	(252)	(2)	–	716
Generation	971	(280)	(1)	–	690
Assets under construction	317	–	(11)	–	306
Other	1,090	(390)	(13)	–	687
	$ 11,026	$ (2,775)	$ (797)	$ (87)	$ 7,367

2007

(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,233	$ (364)	$ (174)	$ –	$ 1,695
Electricity	3,542	(961)	(463)	(91)	2,027
Transmission					
Gas	1,277	(286)	(102)	–	889
Electricity	873	(224)	–	–	649
Generation	914	(240)	–	–	674
Assets under construction	195	–	–	–	195
Other	970	(337)	(14)	–	619
	$ 10,004	$ (2,412)	$ (753)	$ (91)	$ 6,748

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 and conductors, substations, 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, 2008 was $56 million (December 31, 2007 – $51 million) and related accumulated amortization was $24 million (December 31, 2007 – $19 million).

8. Income Producing Properties

2008

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 485	$ (51)	$ 434
Land	61	–	61
Tenant inducements	24	(14)	10
Equipment	56	(23)	33
Construction in progress	3	–	3
	$ 629	$ (88)	$ 541

2007

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 469	$ (42)	$ 427
Land	54	–	54
Tenant inducements	22	(13)	9
Equipment	46	(18)	28
Construction in progress	1	–	1
	$ 592	$ (73)	$ 519

The cost of income producing property assets under capital lease as at December 31, 2008 was $1 million (December 31, 2007 – $6 million) and related accumulated amortization was $0.1 million (December 31, 2007 – $4 million).

9. Goodwill

(in millions)	2008	2007
Balance, beginning of year	$ 1,544	$ 661
Acquisition of Terasen *(Note 21)*	(4)	907
Reversal of restructuring accrual	–	(2)
Step-acquisition of Caribbean Utilities	6	–
Foreign currency translation impacts	29	(22)
Balance, end of year	$ 1,575	$ 1,544

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which 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.

10. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	**2008**	2007
Regulated Utilities			
Terasen Gas Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2007 – 10.71%)	2015–2016	**$ 275**	$ 275
Unsecured Debentures –			
6.29% weighted average fixed rate (2007 – 6.44%)	2009–2038	**1,380**	1,068
Government loan *(Note 27)*	2009	**8**	6
Obligations under capital leases	2012	**10**	9
FortisAlberta			
Senior Unsecured Debentures –			
5.61% weighted average fixed rate (2007 – 5.57%)	2014–2047	**709**	610
FortisBC			
Secured Debentures –			
9.28% weighted average fixed rate (2007 – 9.31%)	2009–2023	**44**	45
Unsecured Debentures –			
6.06% weighted average fixed rate (2007 – 6.06%)	2009–2047	**445**	445
Obligation under capital lease	2032	**26**	26
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.84% weighted average fixed rate (2007 – 7.84%)	2014–2037	**409**	414
Maritime Electric			
Secured First Mortgage Bonds –			
8.10% weighted average fixed rate (2007 – 9.43%)	2010–2038	**152**	92
FortisOntario			
Senior Unsecured Notes – 7.09% fixed rate	2018	**52**	52
Belize Electricity			
Secured:			
US RBTT Merchant Bank loan – 5.75% to 8.15% fixed rate	2010–2012	**5**	6
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate (2007 – 10.36%)	2012–2027	**42**	33
Other loans – 5.81% weighted average fixed rate (2007 – 5.73%)	2009–2015	**11**	11
Other variable interest rate loans	2010–2015	**18**	10
Caribbean Utilities			
Unsecured Senior Loan Notes –			
6.04% weighted average fixed rate (2007 – 6.09%)	2009–2022	**204**	177
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. loan –			
3.91% weighted average fixed and variable rate (2007 – 3.88%)	2013–2016	**14**	13
US First Caribbean International Bank loan – 5.65% fixed rate	2015	**4**	3
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**5**	5
Term loan – 7.55% fixed rate (non-recourse to Fortis Inc.) *(Note 28)*	2028	**61**	62

(in millions)	Maturity Date	**2008**	2007
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
7.02% weighted average fixed rate (2007 – 7.02%)	2010–2017	**$ 212**	$ 220
Senior notes – 7.32% fixed rate	2019	**16**	17
Unsecured:			
Obligation under capital lease	2008	**–**	2
Non-revolving variable interest rate credit facilities	2009–2010	**7**	7
Corporate – Fortis and Terasen			
Unsecured:			
Debentures –			
6.36% weighted average fixed rate (2007 – 6.33%)	2010–2014	**230**	436
US Senior Notes –			
6.23% weighted average fixed rate (2007 – 6.23%)	2014–2037	**426**	347
US Subordinated Convertible Debentures –			
5.50% weighted average fixed rate (2007 – 5.66%)	2016	**44**	45
Capital Securities – 8.00% fixed rate	2040	**125**	126
Long-term classification of credit-facility borrowings *(Note 26)*		**224**	530
Total long-term debt and capital lease obligations		**5,158**	5,092
Less: Deferred financing costs		**(34)**	(33)
Less: Current installments of long-term debt and capital lease obligations		**(240)**	(436)
		$ 4,884	$ 4,623

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
2009	240
2010	219
2011	104
2012	254
2013	85
Thereafter	4,256

Regulated Utilities

FortisBC has a capital lease obligation with respect to the operation of the Brilliant Terminal Station. 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 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.

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

Corporate – Fortis and Terasen

Of the unsecured debentures, $100 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 Yield, plus a premium ranging from 0.43% to 0.87%, 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 $35.46 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 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 $6 million as at December 31, 2008 (December 31, 2007 – $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.

11. Deferred Credits

(in millions)	**2008**	2007
OPEB plan liabilities *(Note 20)*	**$ 129**	$ 112
Defined benefit liabilities *(Note 20)*	**34**	32
Deferred gains on the sale of natural gas transmission and distribution assets	**46**	50
Deferred payment	**43**	40
Other deferred credits	**25**	27
	$ 277	$ 261

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 commitments 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. At December 31, 2008, its present value was $43 million (December 31, 2007 – $40 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, DSU and PSU liabilities and unfunded defined contribution pension liabilities.

12. Non-Controlling Interest

(in millions)	**2008**	2007
Caribbean Utilities	**$ 92**	$ 67
Belize Electricity	**44**	38
Preference shares of Newfoundland Power	**7**	7
Exploits Partnership	**2**	3
	$ 145	$ 115

13. 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		**2008**		2007	
	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**	–	–
Total classified as equity		**14,200,000**	**$ 347**	5,000,000	$ 122

First Preference Shares Classified as Debt

As the First Preference Shares, Series C and Series E are convertible at the option of the shareholder 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 so 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 and 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 and 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 of 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.

As the First Preference Shares, Series F and Series G are not redeemable at the option of the shareholder, 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 the $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%.

13. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

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.

14. Common Shares

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

Issued and Outstanding	**2008**		2007	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Common shares	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126

Common shares issued during the year were as follows:

	2008		2007	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Balance, Beginning of Year	**155,521,313**	**$ 2,126**	104,091,542	$ 829
Public Offering	**11,700,000**	**291**	5,170,000	146
Public Offering – Conversion of Subscription Receipts	**–**	**–**	44,275,000	1,119
Conversion of Debentures	**1,041,871**	**11**	882,626	9
Consumer Share Purchase Plan	**88,686**	**2**	79,463	3
Dividend Reinvestment Plan	**230,601**	**6**	203,763	5
Employee Share Purchase Plan	**272,095**	**7**	240,578	6
Stock Option Plans	**336,351**	**6**	578,341	9
Balance, End of Year	**169,190,917**	**$ 2,449**	155,521,313	$ 2,126

In December 2008, Fortis issued 11.7 million common shares for $25.65 per common 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 1.0 million common shares of the Corporation.

In January 2007, Fortis issued 5.17 million common shares for $29.00 per common share. The common share issue resulted in gross proceeds of approximately $150 million, or approximately $146 million net of after-tax expenses.

In March 2007, to finance a significant portion of the net cash purchase price of Terasen, the Corporation sold approximately 44.3 million Subscription Receipts at $26.00 each for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition of Terasen on May 17, 2007, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt holder also received a cash payment of $0.21 per Subscription Receipt, which was an amount equal to the dividend declared per common share of Fortis to holders of record as of May 4, 2007. The net proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $1.12 billion net of after-tax expenses.

During 2007, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$9 million of the US$20 million debentures into approximately 0.9 million common shares of the Corporation.

As at December 31, 2008, 9.8 million (December 31, 2007 – 6.2 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. During 2008, an additional 5 million common shares were reserved under the dividend reinvestment plan in accordance with an enhancement made to the plan. 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, 2008, 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, 2007 – 2.4 million and 26 million, respectively).

As at December 31, 2008, $3 million (December 31, 2007 – $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 157.4 million for 2008 and 137.6 million for 2007.

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 are as follows:

	2008			2007		
	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	**$ 245**	**157.4**	**$ 1.56**	$ 193	137.6	$ 1.40
Effect of Potential Dilutive Securities:						
Subscription Receipts[(1)]	–	–		–	7.8	
Stock Options	–	1.0		–	1.2	
Preference Shares *(Notes 13 and 17)*	17	13.9		17	11.5	
Convertible Debentures	2	1.4		3	2.8	
	264	**173.7**		213	160.9	
Deduct Anti-Dilutive Impacts:						
Convertible Debentures	–	–		(2)	(1.4)	
Diluted Earnings per Common Share	**$ 264**	**173.7**	**$ 1.52**	$ 211	159.5	$ 1.32

(1) Dilution relates to the period the Subscription Receipts were outstanding from March 15, 2007 to May 16, 2007, prior to their conversion into common shares.

15. 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, 2008, 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:	**2008**	2007
Options outstanding, beginning of year	**3,691,771**	3,550,055
Granted	**827,504**	754,800
Cancelled	**(42,462)**	(34,743)
Exercised	**(336,351)**	(578,341)
Options outstanding, end of year	**4,140,462**	3,691,771
Options vested, end of year	**2,279,240**	1,901,811

December 31, 2008 and 2007

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

Weighted Average Exercise Prices:	2008	2007
Options outstanding, beginning of year	$ **18.86**	$ 16.11
Granted	**28.27**	27.75
Cancelled	**24.20**	22.43
Exercised	**14.48**	13.35
Options outstanding, end of year	**21.04**	18.86

Details of stock options outstanding and vested as at December 31, 2008 are as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
97,842	97,842	$ 9.57	2011
166,473	166,473	$ 12.03	2012
472,393	472,393	$ 12.81	2013
572,528	572,528	$ 15.28	2014
10,000	10,000	$ 15.23	2014
32,793	32,793	$ 14.55	2014
637,902	457,808	$ 18.40	2015
28,000	21,000	$ 18.11	2015
17,500	9,065	$ 20.82	2015
556,615	256,072	$ 22.94	2016
596,232	149,058	$ 28.19	2014
136,832	34,208	$ 25.76	2014
815,352	–	$ 28.27	2015
4,140,462	2,279,240		

The weighted average exercise price of stock options vested as at December 31, 2008 was $16.81.

In February 2008, the Corporation granted 827,504 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $28.27 immediately preceding the date of grant. The fair value of each option granted was $4.76 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 *(%)*	2.90
Expected volatility *(%)*	20.7
Risk-free interest rate *(%)*	3.92
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, 2008 (2007 – $2 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:	2008	2007
DSUs outstanding, beginning of year	69,722	46,959
Granted	27,224	20,859
Granted – notional dividends reinvested	3,671	1,904
DSUs outstanding, end of year	100,617	69,722

For the year ended December 31, 2008, expense of $0.2 million (2007 – $0.8 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:	2008	2007
PSUs outstanding, beginning of year	67,615	66,845
Granted	32,940	19,570
Granted – notional dividends reinvested	3,011	1,883
PSUs paid out	(18,019)	(20,683)
PSUs outstanding, end of year	85,547	67,615

In March 2008, 18,019 PSUs were paid out to the President and CEO of the Corporation at $28.36 per PSU for a total of approximately $0.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2005, 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, 2008, expense of $0.6 million (2007 – $0.6 million) was recorded in relation to the PSU Plan.

16. 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.

	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)

	2007			
(in millions)	Opening balance January 1	Transition amount January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	$ (51)	$ –	$ (31)	$ (82)
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	$ (51)	$ (6)	$ (31)	$ (88)

16. Accumulated Other Comprehensive Loss (cont'd)

During 2008, unrealized foreign currency translation gains of $115 million (2007 – losses of $70 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 gains were partially offset by the effective portion of unrealized after-tax losses of $79 million (2007 – after-tax gains of $39 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.

As at January 1, 2007, in accordance with the transitional provisions of CICA Handbook Section 3865, *Hedges*, a net loss of $5 million associated with unamortized deferred gain and loss balances related to previously cancelled swap agreements was reclassified to accumulated other comprehensive loss. The deferred gain and loss balances are amortized to comprehensive income on a straight-line basis over the life of the related debt.

On January 1, 2007, as required upon initial application of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*, all adjustments to the carrying amount of financial instruments were recognized as an adjustment to the opening balance of accumulated other comprehensive loss. The Corporation was not required to remeasure any assets or liabilities upon adoption of Section 3855; therefore, no adjustments were made to the opening balance of retained earnings.

17. Finance Charges

(in millions)	**2008**	2007
Interest – Long-term debt and capital lease obligations	**$ 329**	$ 266
– Short-term borrowings	**32**	27
AFUDC *(Note 2)*	**(13)**	(8)
Interest earned	**(2)**	(4)
Unrealized foreign exchange loss on long-term debt	**–**	1
Dividends on preference shares *(Notes 13 and 14)*	**17**	17
	$ 363	$ 299

18. Gain on Sale of Property

In December 2007, TGI sold surplus land resulting in an $8 million ($7 million after-tax) gain on the sale.

19. Corporate Taxes

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)	2008	2007
Combined Canadian federal and provincial statutory income tax rate	**33.5%**	36.1%
Statutory income tax rate applied to earnings before corporate taxes and non-controlling interest	**$ 113**	$ 90
Preference share dividends	**6**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(12)**	(18)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(6)**	(3)
Items capitalized for accounting but expensed for income tax purposes	**(33)**	(21)
Difference between capital cost allowance ("CCA") and other deductions claimed for income tax purposes and amounts recorded for accounting purposes[(1)]	**5**	(12)
Impact of reduction in income tax rates on future income taxes	**–**	(6)
Québec Tax Trust and other tax settlements – Terasen[(2)]	**(7)**	2
Maritime Electric tax reassessment	**–**	3
Pension costs	**(2)**	(2)
Other	**1**	(3)
Corporate taxes	**$ 65**	$ 36
Effective tax rate	**19.3%**	14.4%

(1) During 2008, CCA deductions at FortisAlberta were lower than amortization expense. However, during 2007, CCA deductions at FortisAlberta were higher than amortization expense. The higher CCA deductions in 2007 were required to offset taxable income on the sale, in 2007, of the 2006 AESO charges deferral receivable balance.

(2) 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.

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

(in millions)	2008	2007
Canadian		
Current taxes	**$ 47**	$ 33
Future income taxes	**16**	–
	63	33
Foreign		
Current taxes	**4**	3
Future income taxes	**(2)**	–
	2	3
Corporate taxes	**$ 65**	$ 36

19. Corporate Taxes (cont'd)

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

(in millions)	2008	2007
Future income tax liability (asset)		
Income producing properties	$ 26	$ 22
Utility capital assets	17	13
ECAM	16	10
Other regulatory assets and liabilities	2	2
Intangible assets	3	5
Employee future benefits	(14)	(14)
Loss carryforwards	(11)	(10)
Share issue and debt financing costs	(14)	(16)
Unrealized foreign currency translation (losses) gains on long-term debt	(5)	8
Other	2	5
Net future income tax liability	$ 22	$ 25
Current future income tax liability	$ 15	$ 7
Long-term future income tax asset	(54)	(37)
Long-term future income tax liability	61	55
Net future income tax liability	$ 22	$ 25

As at December 31, 2008, the Corporation had approximately $104 million (December 31, 2007 – $51 million) in non-capital and capital loss carryforwards, of which $8 million (December 31, 2007 – $3 million) in capital losses has not been recognized in the financial statements. The non-capital loss carryforwards expire between 2009 and 2028.

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, Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension 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, Terasen Gas companies, Newfoundland Power and Caribbean Utilities commencing December 2008 (2007 – measured as at April 30), and as at September 30 of each year for FortisAlberta, FortisBC and FortisOntario. 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, 2005 for the Corporation and Newfoundland Power; and as of December 31, 2008 for Caribbean Utilities. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2005 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 company.

Actuarial valuations of the pension plans for funding purposes are currently being completed as of December 31, 2008 for the Corporation, Newfoundland Power and one of the pension plans at the Terasen Gas companies. The valuations are expected to be completed in 2009.

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

Plan assets as at December 31

(%)	2008	2007
Canadian equities	42	50
Fixed income	44	38
Foreign equities	8	8
Real estate	6	4
	100	100

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

	2008			2007		
(in millions)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	$ 253	$ 227	$ (26)	$ 254	$ 261	$ 7
FortisAlberta	22	18	(4)	23	20	(3)
FortisBC	117	96	(21)	122	105	(17)
Newfoundland Power	190	212	22	236	260	24
FortisOntario	21	19	(2)	23	21	(2)
Caribbean Utilities	6	3	(3)	5	3	(2)
Fortis Inc.	4	4	–	4	4	–
Total	$ 613	$ 579	$ (34)	$ 667	$ 674	$ 7

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	2008	2007	2008	2007	2008	2007
Change in accrued benefit obligation						
Balance, beginning of year	$ 667	$ 413	$ 44	$ 17	$ 189	$ 109
Liability associated with acquisitions	–	248	–	27	–	79
Current service costs	16	12	1	1	4	4
Employee contributions	8	6	–	–	–	–
Interest costs	36	29	2	2	10	8
Benefits paid	(32)	(25)	(2)	(2)	(4)	(4)
Actuarial gain	(80)	(16)	(4)	(1)	(30)	(8)
Plan amendments	(2)	–	–	–	–	1
Balance, end of year	$ 613	$ 667	$ 41	$ 44	$ 169	$ 189
Change in value of plan assets						
Balance, beginning of year	$ 674	$ 390	$ –	$ –	$ –	$ –
Assets associated with acquisitions	–	256	–	–	–	–
Actual (loss) return on plan assets	(92)	26	–	–	–	–
Benefits paid	(32)	(25)	(2)	(2)	(4)	(4)
Employee contributions	8	6	–	–	–	–
Employer contributions	21	21	2	2	4	4
Balance, end of year	$ 579	$ 674	$ –	$ –	$ –	$ –
Funded status						
(Deficit) surplus, end of year	$ (34)	$ 7	$ (41)	$ (44)	$ (169)	$ (189)
Unamortized net actuarial loss (gain)	152	95	(1)	3	26	61
Unamortized past service costs	7	10	1	1	(2)	(2)
Unamortized transitional obligation	7	7	2	2	15	18
Plan amendment	–	–	–	–	1	–
Employer contributions after measurement date	1	1	–	–	–	–
Accrued benefit asset (liability), end of year	$ 133	$ 120	$ (39)	$ (38)	$ (129)	$ (112)
Deferred pension costs *(Note 6)*	$ 135	$ 121	$ (7)	$ (7)	$ –	$ –
Defined benefit liabilities *(Note 11)*	(2)	(1)	(32)	(31)	–	–
OPEB plan liabilities *(Note 11)*	–	–	–	–	(129)	(112)
	$ 133	$ 120	$ (39)	$ (38)	$ (129)	$ (112)

20. *Employee Future Benefits (cont'd)*

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2008**	2007	**2008**	2007	**2008**	2007
Significant assumptions						
Discount rate during the year *(%)*	**5.25–5.60**	5.00–5.25	**5.25–5.75**	5.00–5.25	**5.25–5.75**	5.00–5.25
Discount rate as at December 31 *(%)*	**6.00–7.50**	5.25–5.60	**6.25–7.50**	5.25–5.75	**6.00–7.50**	5.25–5.75
Expected long-term rate of return on plan assets *(%)*	**3.00–7.50**	6.50–7.50	**–**	–	**–**	–
Rate of compensation increase *(%)*	**3.00–5.00**	3.50–4.25	**3.19–5.00**	3.77–4.25	**3.50–5.00**	3.50–4.25
Health-care cost trend increase as at December 31 *(%)*	**–**	–	**–**	–	**4.41–9.00**	4.50–10.00
Expected average remaining service life of active employees *(years)*	**5–12**	7–13	**4–12**	3–13	**9–15**	10–16
Components of net benefit expense						
Current service costs	**$ 16**	$ 12	**$ 1**	$ 1	**$ 4**	$ 4
Interest costs	**36**	29	**2**	2	**10**	8
Actual loss (return) on plan assets	**92**	(26)	**–**	–	**–**	–
Actuarial gain	**(80)**	(16)	**(4)**	(1)	**(30)**	(8)
Plan amendments	**(2)**	–	**–**	–	**–**	1
Costs arising in the year	**62**	(1)	**(1)**	2	**(16)**	5
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**(141)**	(11)	**–**	–	**–**	–
Actuarial gain	**84**	20	**4**	1	**34**	11
Past service costs	**3**	2	**1**	–	**–**	–
Special termination benefits	**–**	1	**–**	–	**–**	–
Transitional obligation and amendments	**–**	1	**–**	–	**3**	2
Regulatory adjustment	**1**	–	**–**	–	**(7)**	(7)
Net benefit expense	**$ 9**	$ 12	**$ 4**	$ 3	**$ 14**	$ 11

For 2008, the effects of changing the health-care cost trend rate by 1 per cent are as follows:

(in millions)	**1 per cent increase in rate**	**1 per cent decrease in rate**
Increase (decrease) in accrued benefit obligation	**$ 22**	**$ (16)**
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 2008 net defined benefit pension expense, 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 Expense**	**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)	(57)
Impact of decreasing the discount rate assumption by 100 basis points	10	(8)	1	67

During 2008, the Corporation expensed $11 million (2007 – $10 million) related to defined contribution pension plans.

21. Business Acquisitions

2008

Fairmont Newfoundland Hotel

In November 2008, Fortis Properties purchased the Fairmont Newfoundland hotel 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 results of operations 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

2007

a. Terasen

On May 17, 2007, Fortis acquired all of the issued and outstanding common shares of Terasen for aggregate consideration of approximately $3.7 billion. The net cash purchase price of approximately $1.25 billion, including acquisition costs, was primarily financed through proceeds from the issuance of common equity, with the remaining $125 million of the net cash purchase price being financed, on an interim basis, through drawings on the Corporation's committed credit facility.

Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. Terasen is the principal natural gas distributor in British Columbia.

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, Terasen's 30 per cent investment in non-regulated CWLP and Terasen's 100 per cent investment in non-regulated TES have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The 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 substantially all of the individual assets and liabilities associated with the Terasen Gas companies, 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 the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation are related to non-regulated Terasen and its non-regulated investments.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition. The amount of the purchase price assignable to goodwill is entirely associated with the regulated Terasen Gas companies. Approximately $40 million of goodwill is deductible for tax purposes. Of the $11 million in intangible assets, $10 million was assigned as the value associated with customer contracts at CWLP. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which related to periods prior to the Corporation's ownership of Terasen, resulting in a $6 million reduction in goodwill. Partially offsetting the above was a final purchase adjustment of $2 million, which increased goodwill.

21. Business Acquisitions (cont'd)

a. Terasen (cont'd)

(in millions)		Total
Fair value assigned to net assets:		
Utility capital assets	$	2,768
Current assets		361
Goodwill		903
Intangibles		11
Long-term regulatory assets		69
Other assets		42
Current liabilities		(355)
Assumed short-term indebtedness		(275)
Assumed long-term debt (including current portion)		(2,077)
Long-term regulatory liabilities		(29)
Other liabilities		(165)
		1,253
Cash		3
	$	1,256

b. Delta Regina

In August 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan for an aggregate cash purchase price of approximately $50 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing August 2007.

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	$	50

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2008 *($ millions)*	**Terasen Gas Companies – Canadian[1]**	Fortis Alberta	Fortis BC	NF Power	Other Canadian[2]	**Total Electric Canadian**	**Electric Caribbean[3]**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
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	990	1,001	520	**4,085**	**867**	**285**	**559**	**126**	**(40)**	**9,603**
Total assets	**4,624**	1,801	1,211	1,001	583	**4,596**	**1,028**	**285**	**559**	**126**	**(40)**	**11,178**
Gross capital expenditures	**220**	302	117	67	46	**532**	**110**	**19**	**14**	**9**	**–**	**904**
Year ended December 31, 2007 *($ millions)*												
Revenue	905	270	229	491	263	1,253	307	75	191	22	(35)	2,718
Energy supply costs	559	–	67	327	174	568	169	8	–	–	(17)	1,287
Operating expenses	150	122	69	53	29	273	49	14	123	13	(5)	617
Amortization	58	75	31	34	17	157	28	10	14	6	–	273
Operating income	138	73	62	77	43	255	61	43	54	3	(13)	541
Finance charges	80	36	26	34	17	113	15	10	24	70	(13)	299
Gain on sale of property	(8)	–	–	–	–	–	–	–	–	–	–	(8)
Corporate taxes (recoveries)	16	(11)	5	12	10	16	2	8	6	(12)	–	36
Non-controlling interest	–	–	–	1	–	1	13	1	–	–	–	15
Net earnings (loss)	50	48	31	30	16	125	31	24	24	(55)	–	199
Preference share dividends	–	–	–	–	–	–	–	–	–	6	–	6
Net earnings (loss) applicable to common shares	50	48	31	30	16	125	31	24	24	(61)	–	193
Goodwill	907	227	221	–	63	511	126	–	–	–	–	1,544
Identifiable assets	3,540	1,294	914	986	484	3,678	652	235	535	108	(19)	8,729
Total assets	4,447	1,521	1,135	986	547	4,189	778	235	535	108	(19)	10,273
Gross capital expenditures	120	285	147	72	38	542	106	17	13	5	–	803

(1) The Terasen Gas companies were acquired on May 17, 2007.
(2) Includes Maritime Electric and FortisOntario
(3) Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos. Results for 2008 include two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end.

22. *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)	2008	2007
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	$ 17	$ 15
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	2	2
Corporate to Regulated Electric Utilities – Caribbean	5	1
Corporate to Fortis Properties	8	8

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	2008	2007
Interest paid	$ 373	$ 288
Income taxes paid	33	53

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. 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. Fortis generally finances a significant portion of acquisitions with proceeds from common and preference share issuances.

The consolidated capital structure of Fortis is presented in the following table.

	As at December 31, 2008		As at December 31, 2007	
	(in millions)	*(%)*	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash)[(1)]	$ 5,468	59.5	$ 5,476	64.3
Preference shares[(2)]	667	7.3	442	5.2
Common shareholders' equity	3,046	33.2	2,601	30.5
Total	$ 9,181	100.0	$ 8,519	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, 2008, the Corporation and its subsidiaries, except for 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, Belize Electricity does not meet certain debt covenant financial ratios related to loans totalling $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default on a $61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. See Note 28 for a further discussion of 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:

	December 31, 2008		December 31, 2007	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents[(1)]	$ 66	$ 66	$ 58	$ 58
Loans and receivables				
Trade and other accounts receivable[(1)(2)(3)]	674	674	630	630
Other receivables due from customers[(1)(3)(4)]	8	8	7	7
Other financial liabilities				
Short-term borrowings[(1)(3)]	410	410	475	475
Trade and other accounts payable[(1)(3)(5)]	782	782	714	714
Dividends payable[(1)(3)]	47	47	43	43
Customer deposits[(1)(3)(6)]	6	6	5	5
Long-term debt, including current portion[(7)(8)]	5,088	4,927	5,023	5,635
Preference shares, classified as debt[(7)(9)]	320	329	320	346

(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 balance sheet

(3) Carrying value approximates amortized cost

(4) Included in deferred charges and other assets on the balance sheet

(5) Included in accounts payable and accrued charges on the balance sheet

(6) Included in deferred credits on the balance sheet

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

(8) Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 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 $268 million as at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, 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 by 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 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.

	2008				2007	
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)]	1 to 2	2	$ –	$ –	$ –	$ –
Foreign exchange forward contract	<3	1	7	7	–	–
Natural gas derivatives:[(2)]						
Swaps and options	Up to 3	228	(84)	(84)	(79)	(79)
Gas purchase contract premiums	Up to 3	74	(8)	(8)	5	5

(1) Interest rate swap contracts mature in July 2009 and October 2010. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 6.16 per cent and 5.32 per cent, respectively.

(2) The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – in accounts payable and accounts receivable).

25. *Financial Instruments (cont'd)*

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 the following market risks: • Foreign exchange risk • Interest rate risk • 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 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, 2008, its gross credit risk exposure was approximately $87 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, 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 aging analysis of the Corporation's consolidated trade and other accounts receivable is as follows:

(in millions)	As at December 31, 2008
Not past due	$ 587
Past due 0–30 days	70
Past due 31–60 days	14
Past due 61 days and over	19
	690
Less: allowance for doubtful accounts	(16)
	$ 674

As at December 31, 2008, other receivables due from customers of $8 million and the receivable associated with the foreign exchange forward contract of $7 million will be received over the next six years, with $7 million expected to be received in 2009, $5 million over 2010 and 2011, $2 million over 2012 and 2013 and $1 million in 2014.

Liquidity Risk

The Corporation's financial position could be adversely affected if it, or its operating subsidiaries, fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and 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.

To 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.

Committed credit facilities at Fortis are 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 consolidated annual long-term debt maturities and repayments are expected to be approximately $180 million. The combination of available credit facilities and low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing and access to capital markets.

As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which $1.5 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, 2008**	Total as at December 31, 2007
Total credit facilities	$ 715	$ 1,500	$ 13	**$ 2,228**	$ 2,234
Credit facilities utilized:					
Short-term borrowings	–	(410)	–	**(410)**	(475)
Long-term debt *(Note 10)*[(1)]	(32)	(192)	–	**(224)**	(530)
Letters of credit outstanding	(1)	(102)	(1)	**(104)**	(159)
Credit facilities available	$ 682	$ 796	$ 12	**$ 1,490**	$ 1,070

[(1)] As at December 31, 2008, credit-facility borrowings classified as long-term debt included $8 million that was included in current installments of long-term debt and capital lease obligations on the balance sheet.

As at December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and its subsidiaries' credit facilities have been 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 Inc. has a $100 million unsecured committed revolving credit facility, maturing May 2009, that is available for general corporate purposes. Letters of credit of $50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Fortis has a $600 million unsecured committed revolving credit facility, maturing May 2012, and a $15 million unsecured demand 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 in 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 and, 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 2009. 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 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 uncommitted demand facility.

Maritime Electric had a $50 million unsecured demand revolving credit facility at December 31, 2008. In March 2009, the credit facility was renegotiated and converted into a 364-day revolving committed credit facility.

FortisOntario has secured lines of credit totalling $20 million of which $12 million is authorized solely for letters of credit.

26. Financial Risk Management (cont'd)

Regulated Utilities (cont'd)

Caribbean Utilities has credit facilities of US$33 million ($40 million), comprised of a capital expenditure line of credit of US$18 million ($22 million), including amounts available for letters of credit, a US$7.5 million ($9 million) operating line of credit and a US$7.5 million ($9 million) catastrophe standby loan.

Fortis Turks and Caicos has credit facilities of US$21 million ($25.5 million), comprised of an operating credit facility of US$5 million ($6 million), a capital expenditure line of credit of US$7 million ($8.5 million) and a US$9 million ($11 million) emergency standby loan.

Belize Electricity has a BZ$2 million ($1 million) and BZ$5 million ($3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank, respectively.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity requiring the Company to repay approximately BZ$4 million ($2 million) outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ$5 million ($3 million) credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the credit facility was undrawn.

Fortis Properties

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

Furthermore, the Corporation and its currently rated subsidiaries target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2008, 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.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2008.

Financial Liabilities

(in millions)	≤ 1 year	>1–3 years	4–5 years	>5 years	**Total**
Short-term borrowings	$ 410	$ –	$ –	$ –	**$ 410**
Trade and other accounts payable	782	–	–	–	**782**
Natural gas derivatives	70	22	–	–	**92**
Dividends payable	47	–	–	–	**47**
Customer deposits	2	2	1	1	**6**
Long-term debt, including current portion[(1)]	240	319	335	4,228	**5,122**
Interest obligations on long-term debt	304	698	583	3,993	**5,578**
Preference shares, classified as debt	–	–	–	320	**320**
	$ 1,855	$ 1,041	$ 919	$ 8,542	**$ 12,357**

[(1)] Excluding deferred financing costs of $34 million included in the carrying value as per Note 25

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, 2008, all of the Corporation's corporately held US$403 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2008, the Corporation had approximately 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 of the US dollar relative to the Canadian dollar would have increased earnings by $0.6 million for the year ended December 31, 2008 and would have decreased other comprehensive income by $25 million for the year ended December 31, 2008. 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 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 other comprehensive income by $32 million for the year ended December 31, 2008.

TGVI's US dollar payments under a contract for the construction of an LNG storage facility exposes TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI has entered into a foreign exchange forward contract to hedge this exposure. At December 31, 2008, a 5 per cent appeciation 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 earnings by $3 million for the year ended December 31, 2008. 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 other comprehensive income.

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 2008, the Terasen Gas companies and Fortis Properties were parties to interest rate swap agreements that effectively fixed the interest rates on their variable-rate borrowings. During the fourth quarter of 2008, the Terasen Gas companies' 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 $5 million for the year ended December 31, 2008. 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, 2008, a 100 basis point increase in interest rates as it affects the measurement of fair value of the interest rate swap agreements would have increased other comprehensive income by $0.1 million during the year ended December 31, 2008.

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 $0.9 million for the year ended December 31, 2008.

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 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 increased and, in the absence of rate regulation, other comprehensive income would have increased by $54 million for the year ended December 31, 2008. However, the Terasen Gas companies defer any changes in 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 $54 million.

27. Commitments

(in millions)	Total	< 1 year	1–3 years	4–5 years	> 5 years
Gas purchase contract obligations[1]	**$ 466**	$ 416	$ 50	$ –	$ –
Power purchase obligations					
FortisBC[2]	**2,829**	40	76	78	2,635
FortisOntario[3]	**561**	45	94	99	323
Maritime Electric[4]	**72**	52	2	2	16
Belize Electricity[5]	**16**	4	4	2	6
Capital cost[6]	**400**	16	41	41	302
Joint-use asset and shared service agreements[7]	**62**	4	7	6	45
Office lease – FortisBC[8]	**19**	1	4	2	12
Operating lease obligations[9]	**166**	18	33	29	86
Other	**25**	4	10	6	5
Total	**$ 4,616**	$ 600	$ 321	$ 265	$ 3,430

[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, 2008.

[2] Power purchase obligations of 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 natural flow 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 contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. 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.

[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 and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's commitments table above.

[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 the NB Power Point Lepreau Nuclear Generating Station 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 the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 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 extensions 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 transmission and distribution asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

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 authorities. The consolidated capital program of the Corporation, including non-regulated segments, is forecasted to be approximately $1 billion for 2009. This commitment 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 are 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 and long-term debt 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 2008 and TGVI is expected to make an $8 million repayment on the loans in 2009 (2008 – $6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was $61 million with $8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the commitments table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's RDDA and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

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-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

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.

Based on the last completion of actuarial valuations, the Corporation's required consolidated defined benefit pension plan funding contributions are expected to be approximately $17 million for 2009 and $12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome, in 2009, of December 31, 2008 actuarial valuations for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

28. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course 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 it is recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia (Note 4 *(ix)*).

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.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, 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 a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all 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 the NB Power Point Lepreau Nuclear Generating Station 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. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, 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.

FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately $9 million (US$7 million). There was no impact on the consolidated financial statements as a result of the settlement of these legal proceedings.

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a $61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with the Exploits Partnership's lenders with respect to the above 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-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been classified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

29. Subsequent Events

In February 2009, FortisAlberta issued $100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued $100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay $60 million of unsecured debentures that mature in June 2009.

30. Comparative Figures

Certain comparative figures have been reclassified to comply with the current year's classifications.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2008**	2007	2006[1]	2005[1]
Revenue, including equity income	**3,903**	2,718	1,472	1,441
Energy supply costs and operating expenses	**2,855**	1,904	939	926
Amortization	**348**	273	178	158
Finance charges	**363**	299	168	154
Corporate taxes	**65**	36	32	70
Results of discontinued operations, gains on sales and other unusual items	**–**	8	2	10
Non-controlling interest	**13**	15	8	6
Preference share dividends	**14**	6	2	–
Net earnings applicable to common shares	**245**	193	147	137
Balance Sheets *(in $ millions)*				
Current assets	**1,150**	1,038	405	299
Goodwill	**1,575**	1,544	661	512
Other long-term assets	**545**	424	331	471
Utility capital assets and income producing properties	**7,908**	7,267	4,044	3,315
Total assets	**11,178**	10,273	5,441	4,597
Current liabilities	**1,697**	1,804	558	412
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**739**	688	477	477
Long-term debt and capital lease obligations (excluding current portion)	**4,884**	4,623	2,558	2,136
Non-controlling interest	**145**	115	130	39
Preference share (classified as debt)	**320**	320	320	320
Shareholders' equity	**3,393**	2,723	1,398	1,213
Cash Flows *(in $ millions)*				
Operating activities	**663**	373	263	304
Investing activities	**854**	2,033	634	467
Financing activities	**387**	1,826	456	224
Dividends, excluding dividends on preference shares classified as debt	**191**	146	77	64
Financial Statistics				
Return on average common shareholders' equity *(%)*	**8.70**	10.00	11.87	12.40
Capitalization Ratios *(%)* (year end)				
Total debt and capital lease obligations (net of cash)	**59.5**	64.3	61.1	58.7
Preference shares (classified as debt and equity)	**7.3**	5.2	10.0	8.6
Common shareholders' equity	**33.2**	30.5	28.9	32.7
Interest Coverage *(x)*				
Debt	**1.9**	1.9	2.2	2.5
All fixed charges	**1.8**	1.7	2.0	2.1
Total gross capital expenditures *(in $ millions)*	**904**	803	500	446
Common share data				
Book value per share (year end) *($)*	**17.97**	16.69	12.19	11.74
Average common shares outstanding *(in millions)*	**157.4**	137.6	103.6	101.8
Basic earnings per common share *($)*	**1.56**	1.40	1.42	1.35
Dividends declared per common share *($)*	**1.010**	0.880	0.700	0.605
Dividends paid per common share *($)*	**1.000**	0.820	0.670	0.588
Dividend payout ratio *(%)*	**64.1**	58.6	47.2	43.7
Price earnings ratio *(x)*	**15.8**	20.7	21.0	18.0
Share trading summary				
High price *($)* (TSX)	**29.94**	30.00	30.00	25.64
Low price *($)* (TSX)	**20.70**	24.50	20.36	17.00
Closing price *($)* (TSX)	**24.59**	28.99	29.77	24.27
Volume *(in thousands)*	**132,108**	100,920	60,094	37,706

(1) 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. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets.

2004	2003	2002	2001	2000	1999	1998
1,146	843	715	628	580	505	473
766	579	477	418	418	356	340
114	62	65	62	52	45	42
122	86	74	65	56	46	44
47	38	32	29	17	28	23
–	–	–	4	3	–	4
6	4	4	4	3	1	1
–	–	–	–	–	–	–
91	74	63	54	37	29	27
293	191	180	135	166	93	94
514	65	60	33	36	39	42
418	345	241	172	163	122	121
2,713	1,563	1,459	1,246	1,056	930	750
3,938	2,164	1,940	1,586	1,421	1,184	1,007
538	296	334	272	225	230	148
–	–	–	–	–	16	16
138	62	39	32	24	27	22
1,905	1,031	941	746	678	488	424
37	37	40	36	32	29	8
320	123	–	50	50	50	50
1,000	615	586	450	412	344	339
272	157	134	94	97	85	69
1,026	308	349	240	241	122	66
777	232	261	171	178	67	16
51	38	35	30	28	24	24
11.28	12.30	12.23	12.44	9.73	8.55	8.24
61.4	60.0	65.2	63.9	60.4	59.6	53.4
9.4	6.7	–	3.6	4.3	5.1	6.0
29.2	33.3	34.8	32.5	35.3	35.3	40.6
2.3	2.2	2.3	2.3	2.1	2.3	2.2
2.0	2.1	2.2	2.2	1.9	2.1	2.0
279	208	229	149	158	86	65
10.45	8.82	8.50	7.50	6.97	6.55	6.52
84.7	69.3	65.1	59.5	54.1	52.2	51.5
1.07	1.06	0.97	0.90	0.68	0.56	0.53
0.548	0.525	0.498	0.470	0.460	0.455	0.450
0.540	0.520	0.485	0.468	0.460	0.453	0.450
50.3	48.9	49.9	51.9	67.6	80.8	84.9
16.2	13.9	13.5	13.0	13.2	14.0	18.0
17.75	15.24	13.28	11.89	9.19	9.93	12.03
14.23	11.63	10.76	8.56	6.88	7.29	8.75
17.38	14.73	13.13	11.74	9.00	7.85	9.56
29,254	31,180	21,676	21,460	26,760	9,024	12,356

Board of Directors (l-r): David G. Norris, Peter E. Case, Harry McWatters, John S. McCallum, Geoffrey F. Hyland, Roy P. Rideout, Linda L. Inkpen, Michael A. Pavey, H. Stanley Marshall, Frank J. Crothers

Board of Directors

Geoffrey F. Hyland ∗★✱ *Chair, Fortis Inc., Caledon, ON*
Mr. Hyland, 64, 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 Enerflex Systems Income Fund, SCITI Total Return Trust and Exco Technologies Limited.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 54, 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. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, Bahamas*
Mr. Crothers, 64, 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 former 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. Mr. Crothers also serves as a Director of Franklin Templeton Resources, Talon Metals Corp, Fidelity Merchant Bank & Trust (Cayman) Limited and Victory Nickel Inc.

Linda L. Inkpen ★ *Corporate Director, St. John's, NL*
Dr. Inkpen, 61, joined the Fortis Inc. Board in 1994. She retired from her medical practice in December 2008 after 35 years of service and is past Chair of the Medical Advisory Committee for the St. John's Hospitals for Eastern Health. Dr. Inkpen is a past President of the College of the North Atlantic. She also served on the Royal Commission on Employment and Unemployment. Dr. Inkpen is past Chair of the Boards of Fortis Properties Corporation and Newfoundland Power Inc. She will be retiring from the Fortis Inc. Board at the Annual Meeting on May 5, 2009.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 58, 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, 65, 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, 63, 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.

David G. Norris ∗✱ *Corporate Director, St. John's, NL*
Mr. Norris, 61, 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 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, 61, 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, 61, 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 the Halifax International Airport Authority and NAV CANADA.

∗ Audit Committee
★ Governance and Nominating Committee
✱ Human Resources Committee

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Fortis Inc. Officers (l-r): Barry Perry, VP, Finance and CFO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Stan Marshall, President and CEO; Ronald McCabe, VP, General Counsel and Corporate Secretary

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, 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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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.

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 8, 2009	August 7, 2009
November 6, 2009	February 5, 2010

Dividend Payment Dates

June 1, 2009	September 1, 2009
December 1, 2009	March 1, 2010

Earnings Release Dates

April 30, 2009	August 5, 2009
November 5, 2009	February 4, 2010

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

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. 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 Inc. 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. 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; and First Preference Shares, Series G 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 and FTS.PR.G, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 5, 2009
10:30 a.m.
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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

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Delivering long-term value for customers and shareholders.