FORTIS INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

March 13, 2009

ANNUAL INFORMATION FORM
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DEFINITIONS OF CERTAIN TERMS

Certain terms used in the Annual Information Form for the year ended December 31, 2008 are defined below:

"2008 Annual Information Form" means the Fortis Inc. Annual Information Form for the year ended December 31, 2008;

"Abitibi-Consolidated" means Abitibi-Consolidated Company of Canada;

"Advisory Panel" means the Advisory Panel on Canada's System of International Taxation;

"AIP" means agreement in principle;

"AUC" means Alberta Utilities Commission;

"BC Hydro" means BC Hydro and Power Authority;

"BCUC" means British Columbia Utilities Commission;

"BECOL" means Belize Electric Company Limited;

"Belize Electricity" means Belize Electricity Limited;

"BEPC" means Brilliant Expansion Power Corporation;

"BEWU" means Belize Energy Workers Union;

"Board" means Board of Directors of Fortis Inc.;

"BPC" means Brilliant Power Corporation;

"BZ" means Belizean currency, which is pegged to the United States currency (BZ$2.00 = US$1.00);

"Canadian GAAP" means Canadian generally accepted accounting principles;

"Canadian Niagara Power" means Canadian Niagara Power Inc.;

"Caribbean Utilities" means Caribbean Utilities Company, Ltd.;

"CAW" means Canadian Auto Workers-Retail/Wholesale;

"CEP" means Communications, Energy and Paperworkers Union of Canada;

"CFE" means Comisión Federal de Electricidad;

"CIP" means capital investment plan;

"COPE" means Canadian Office & Professional Employees Union;

"Cornwall Electric" means Cornwall Street Railway, Light and Power Company, Limited;

“Corporation” means Fortis Inc.;

“COS” means cost of service;

“CPC/CBT” means Columbia Power Corporation and the Columbia Basin Trust;

“CPA” means Canal Plant Agreement;

“CPRSA” means Cost of Power Rate Stabilization Account;

“CRA” means Canada Revenue Agency;

“CPI” means consumer price index;

“CRS” means Cost-Recovery Surcharge;

“CUPE” means Canadian Union of Public Employees;

“DBRS” means DBRS Limited;

“ECAM” means energy cost adjustment mechanism;

“ERA” means Electricity Regulatory Authority;

“Exploits Partnership” means Exploits River Hydro Partnership between Abitibi-Consolidated and Fortis Properties;

“External Auditor” means the firm of chartered accountants registered with the Canadian Public Accountability Board or its successor and appointed by the shareholders of the Corporation to act as external auditor of the Corporation;

“FEBL” means Fortis Energy (Bermuda) Limited;

“FERC” means United States Federal Energy Regulatory Commission;

“First Preference Share, Series G” means Cumulative Redeemable Five-Year Fixed-Rate Reset First Preference Shares, Series G;

“Fortis” means Fortis Inc.;

“FortisAlberta” means FortisAlberta Inc.;

“FortisAlberta Holdings” means FortisAlberta Holdings Inc.;

“FortisBC” means, collectively, the operations of FortisBC Inc. and its parent company, Fortis Pacific Holdings Inc., but excluding its wholly owned partnership, Walden Power Partnership;

“FortisBC Inc.” means FortisBC Inc.;

“FortisOntario” means, collectively, the operations of Canadian Niagara Power and Cornwall Electric. Included in Canadian Niagara Power’s accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc.;

"FortisOntario Inc." means the successor to Canadian Niagara Power Company, Limited and the parent company of Canadian Niagara Power and Cornwall Electric;

"Fortis Pacific Holdings" means Fortis Pacific Holdings Inc.;

"Fortis Properties" means Fortis Properties Corporation;

"Fortis Turks and Caicos" means, collectively, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd.;

"FortisUS Energy" means FortisUS Energy Corporation;

"FortisWest" means FortisWest Inc.;

"GWh" means gigawatt hour(s);

"Hydro One" means Hydro One Networks Inc.;

"IBEW" means International Brotherhood of Electrical Workers;

"IESO" means Independent Electricity System Operator of Ontario;

"IFRS" means International Financial Reporting Standards;

"IRAC" means Island Regulatory and Appeals Commission;

"IRM" means Incentive Regulation Mechanism;

"ISO" means International Organization for Standardization;

"kWh" means kilowatt hour(s);

"MD&A" means the Corporation's Management Discussion and Analysis, located on pages 20 through 79 of the Corporation's 2008 Annual Report to Shareholders, prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations, in respect of the Corporation's annual and interim financial statements;

"Management" means, collectively, senior officers of the Corporation;

"Maritime Electric" means Maritime Electric Company, Limited;

"Moody's" means Moody's Investors Service;

"MW" means megawatt(s);

"NB Power" means New Brunswick Power Corporation;

"Newfoundland Hydro" means Newfoundland and Labrador Hydro Corporation;

"Newfoundland Power" means Newfoundland Power Inc.;

"NSA" means Negotiated Settlement Agreement;

“OEB” means Ontario Energy Board;

“Other Canadian Electric Utilities” means, collectively, the operations of FortisOntario and Maritime Electric;

“PBR” means performance-based rate-setting methodology for regulation of public utilities;

“PIF” means productivity improvement factor;

“PJ” means petajoule(s);

“Point Lepreau Station” means NB Power Point Lepreau Nuclear Generating Station;

“Port Colborne Hydro” means Port Colborne Hydro Inc.;

“PUB” means Newfoundland and Labrador Board of Commissioners of Public Utilities;

“PUC” means Public Utilities Commission (Belize);

“ROA” means regulated rate of return on rate base assets;

“ROE” means rate of return on common shareholders’ equity;

“S&P” means Standard & Poor’s;

“Teck Cominco” means Teck Cominco Metals Ltd.;

“Terasen Gas companies” means, collectively, the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.;

“Terasen” means Terasen Inc., the holding company of the Terasen Gas companies;

“TGI” means Terasen Gas Inc.;

“TGVI” means Terasen Gas (Vancouver Island) Inc.;

“TGWI” means Terasen Gas (Whistler) Inc.;

“TIEA” means tax information-exchange agreements;

“TJ” means terajoule(s);

“UFCW” means United Food and Commercial Workers;

“USW” means United Steel Workers;

“UUWA” means United Utility Workers Association;

“VAD” means value-added delivery;

“Village” means the Village of Philadelphia, New York;

“VINGPA” means Vancouver Island Natural Gas Pipeline Agreement; and

“Walden” means Walden Power Partnership.

1.0 CORPORATE STRUCTURE

The 2008 Annual Information Form has been prepared in accordance with National Instrument 52-102 – *Continuous Disclosure Obligations*. Financial information has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars unless otherwise specified.

Except as otherwise stated, the information in the 2008 Annual Information Form is given as of December 31, 2008.

Fortis includes forward-looking information in the 2008 Annual Information Form 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 2008 Annual Information Form 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 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 TGVI 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 IFRS; 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 "Risk Factors" in the 2008 Annual Information Form.*

All forward-looking information in the 2008 Annual Information Form 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.

1.1 Name and Incorporation

Fortis is a holding company that was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977 and continued under the *Corporations Act* (Newfoundland and Labrador) on August 28, 1987.

The articles of incorporation of the Corporation were amended to: (a) change its name to Fortis Inc. on October 13, 1987; (b) set out the rights, privileges, restrictions and conditions attached to the Common Shares on October 15, 1987; (c) designate 2,000,000 First Preference Shares, Series A on September 11, 1990; (d) replace the class rights, privileges, restrictions and conditions attaching to the First Preference Shares and the Second Preference Shares on July 22, 1991; (e) designate 2,000,000 First Preference Shares, Series B on December 13, 1995; (f) designate 5,000,000 First Preference Shares, Series C on May 27, 2003; (g) designate 8,000,000 First Preference Shares, Series D and First Preference Shares, Series E on January 23, 2004; (h) amend the redemption provisions attaching to the First Preference Shares, Series D on July 15, 2005; (i) designate 5,000,000 First Preference Shares, Series F on September 22, 2006; and (j) designate 9,200,000 First Preference Shares, Series G on May 20, 2008.

Fortis redeemed all of its outstanding First Preference Shares, Series A and First Preference Shares, Series B on September 30, 1997 and December 2, 2002, respectively. On June 3, 2003, Fortis issued 5,000,000 First Preference Shares, Series C. On January 29, 2004, Fortis issued 8,000,000 First Preference Units, each unit consisting of one First Preference Share, Series D and one Warrant. During 2004, 7,993,500 First Preference Units were converted into 7,993,500 First Preference Shares, Series E and 6,500 First Preference Shares, Series D remained outstanding. On September 20, 2005, the 6,500 First Preference Shares, Series D were redeemed by the Corporation. On September 28, 2006, Fortis issued 5,000,000 First Preference Shares, Series F. On May 23, 2008, Fortis issued 8,000,000 First Preference Shares, Series G and on June 4, 2008 issued an additional 1,200,000 First Preference Shares, Series G, following the exercise of an over-allotment option in connection with the offering of the 8,000,000 First Preference Shares, Series G.

The corporate head and registered office of Fortis is located at the Fortis Building, Suite 1201, 139 Water Street, P.O. Box 8837, St. John's, NL, Canada, A1B 3T2.

1.2 Inter-Corporate Relationships

Fortis is principally an international distribution utility holding company. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. As at December 31, 2008, regulated utility assets comprised approximately 92 per cent of the Corporation's total assets, with the balance primarily comprised of non-regulated generation assets, mainly hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial real estate in Canada.

The following table lists the principal subsidiaries of the Corporation, their jurisdictions of incorporation and the percentage of votes attaching to voting securities held directly or indirectly by the Corporation as at March 13, 2009. This table excludes certain subsidiaries, the total assets of which individually constituted less than 10 per cent of the Corporation's consolidated assets as at December 31, 2008, or the total revenues of which individually constituted less than 10 per cent of the Corporation's 2008 consolidated revenues. Additionally, the principal subsidiaries together comprise 82 per cent of the Corporation's consolidated assets as at December 31, 2008 and 82 per cent of the Corporation's 2008 consolidated revenue.

Principal Subsidiaries

Subsidiary	**Jurisdiction of Incorporation**	**Percentage of votes attaching to voting securities beneficially owned, controlled or directed by the Corporation**
Terasen	British Columbia	100
FortisAlberta [(1)]	Alberta	100
FortisBC Inc. [(2)]	British Columbia	100
Newfoundland Power	Newfoundland and Labrador	93.7 [(3)]
Caribbean Utilities	Cayman Islands	57 [(4)]

(1) FortisAlberta Holdings, an Alberta corporation, owns all of the shares of FortisAlberta. FortisWest, a Canadian corporation, owns all of the shares of FortisAlberta Holdings. Fortis owns all of the shares of FortisWest.

(2) Fortis Pacific Holdings, a British Columbia corporation, owns all of the shares of FortisBC Inc. FortisWest, a Canadian corporation, owns all of the shares of Fortis Pacific Holdings. Fortis owns all of the shares of FortisWest.

(3) Fortis owns all of the common shares; 182,300 First Preference Shares, Series G; 33,181 First Preference Shares, Series B; 13,000 First Preference Shares, Series D and 1,713 First Preference Shares, Series A of Newfoundland Power which, at March 13, 2009, represented 93.7 per cent of its voting securities. The remaining 6.3 per cent of Newfoundland Power's voting securities consist of First Preference Shares, Series A, B, D and G which are primarily held by the public.

(4) FEBL owns 15,989,329 of the Class A Ordinary Shares of Caribbean Utilities which, at March 13, 2009, represented approximately 57 per cent of its voting securities. The remaining 43 per cent of Caribbean Utilities' voting securities consist of Class A Ordinary Shares which are primarily held by the public. Fortis owns all of the shares of FEBL.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 Three-Year History

Over the past three years, the business operations of Fortis have increased significantly. Total assets have grown more than 2.4 times from $4.6 billion as at December 31, 2005 to $11.2 billion as at December 31, 2008. The Corporation's shareholders' equity has also grown 2.8 times from $1.2 billion as at December 31, 2005 to $3.4 billion as at December 31, 2008. Over the past three years, net earnings applicable to common shares have increased from $137 million in 2005 to $245 million in 2008.

The significant growth reflects the Corporation's profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The significant growth over the past three years primarily reflected the approximate $3.7 billion acquisition of Terasen in May 2007. The addition of Terasen's gas distribution business doubled the Corporation's investment in regulated rate base assets and marked the Corporation's expansion into natural gas distribution. In addition, Fortis has increased its regulated utility investments in the Caribbean through the acquisition of Fortis Turks and Caicos and the acquisition of a controlling interest in Caribbean Utilities, both of which occurred in 2006. The Corporation has increased its non-regulated investments over the last three years through the acquisition of six hotels in Canada.

Organic growth has been driven by the capital expenditure programs at FortisAlberta and FortisBC. Total assets at FortisAlberta and FortisBC have grown by approximately 50 per cent and 28 per cent, respectively, over the past three years.

2.2 Outlook

The Corporation maintains a profitable growth strategy for its principal businesses of regulated gas and electricity distribution. This strategy includes a combination of growth through acquisitions and organic growth through the Corporation's consolidated capital expenditure program.

The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Over the next five years, the Corporation's 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 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.

Consolidated gross capital expenditures for 2009 are expected to be approximately $1 billion, as summarized in the following table.

Fortis Forecast Gross Capital Expenditures Year Ending December 31, 2009	
	($ millions)
Terasen Gas Companies	287
FortisAlberta	292
FortisBC	142
Newfoundland Power	65
Other Canadian Electric Utilities	34
Regulated Electric Utilities – Caribbean	118
Non-Regulated Utility	56
Fortis Properties	33
Total	**1,027**

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's capital program should drive growth in earnings and dividends. 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.

3.0 DESCRIPTION OF THE BUSINESS

Fortis is principally an international distribution utility holding company. Its core business is highly regulated and is segmented 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 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 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 following sections describe the operations in each of the Corporation's reportable segments.

3.1 Regulated Gas Utilities - Canadian

3.1.1 *Terasen Gas Companies*

The Regulated Gas Utilities - Canadian segment comprises the gas distribution business of TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies, which Fortis acquired through the acquisition of 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 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.

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

Market and Sales

The Terasen Gas companies' annual customer gas volumes increased to 221,122 TJ in 2008 from 220,977 TJ in 2007. Revenue was $1.90 billion in 2008 compared to $1.75 billion in 2007. Financial results for the Terasen Gas companies are included in the consolidated financial statements of the Corporation from the date of acquisition, May 17, 2007. The Terasen Gas companies' gas volumes and revenue from the date of acquisition to December 31, 2007 were 118,309 TJ and $905 million, respectively.

The following table compares the composition of 2008 and 2007 gas rate revenue and gas volumes by customer class of the Terasen Gas companies.

Terasen Gas Companies Gas Rate Revenue and Gas Volumes by Customer Class				
	Revenue *(per cent)*		**PJ Volumes** *(per cent)*	
	2008	2007 (1)	**2008**	2007 (1)
Residential	**57.7**	57.1	**35.5**	33.9
Commercial	**33.1**	32.9	**19.9**	19.1
Small industrial	**1.7**	1.9	**1.4**	1.6
Large industrial and other	**0.1**	0.1	**0.1**	0.1
Total natural gas sales	**92.6**	92.0	**56.9**	54.7
Transportation and other	**7.4**	8.0	**43.1**	45.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *The 2007 figures are for the year ended December 31, 2007. The Corporation acquired the Terasen Gas companies on May 17, 2007; therefore, only revenue since May 17, 2007 is reflected in the consolidated financial statements of the Corporation.*

Gas Purchase Agreements

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, the Terasen Gas companies purchase supply from a select list of producers, aggregators and marketers by adhering to strict standards of counterparty creditworthiness and contract execution/management procedures. TGI contracts for approximately 113 PJ of baseload and seasonal supply, of which 81 PJ is delivered off the Spectra Energy Gas transmission system and 14 PJ is comprised primarily of Alberta-sourced supply transported into British Columbia via TransCanada Pipelines Limited’s Alberta and British Columbia systems. The remaining 18 PJ of baseload and seasonal supply is sourced at Sumas, British Columbia. TGVI contracts for approximately 11 PJ of annual supply comprised of base load and seasonal contracts of which approximately 9 PJ is delivered off the Spectra Energy Gas transmission system and 2 PJ sourced directly at Sumas.

Through the operation of regulatory deferrals, any difference between the forecasted cost of natural gas purchases, as reflected in customer rates, and the actual cost of natural gas purchases is recovered from, or refunded to, customers in future rates. The majority of supply contracts in the current portfolio are seasonal for either the summer period (April to October) or winter period (November to March) with a few contracts one year or longer in length.

The Spectra Energy Gas transmission and TransCanada Pipeline Limited transportation tolls are regulated by the National Energy Board, whose responsibilities include regulating pipeline tolls. The Terasen Gas companies pay both fixed and variable charges for use of the pipelines, which are recovered through rates paid by its customers.

Peak Shaving Arrangements

TGI and TGVI incorporate peak shaving and gas storage facilities into its portfolio to:

i. manage the load factor of baseload supply contracts throughout the year;
ii. eliminate the risk of supply shortages during a peak throughput day;
iii. reduce the cost of gas during winter months; and
iv. balance daily supply and demand on the distribution system.

The Terasen Gas companies' peak shaving and storage assets and contracts for 2009 include up to 30 PJ in storage capacity at various locations throughout British Columbia, Alberta and the Pacific Northwest of the United States. These facilities can deliver a maximum daily rate of 574 TJ on a combined basis.

TGVI maintains storage contracts with Unocal Canada Limited at the Aitken Creek Storage facility in Northern British Columbia and Northwest Natural Gas Company at the Mist Storage facility in Oregon, United States. TGVI's Aitken Creek storage contract consists of 2 PJ of capacity with 14 TJ of daily deliverability and its Mist storage contract consists of 0.69 PJ of capacity with 26 TJ of daily deliverability. TGVI also has access to an estimated 26 TJ of daily peak supply deliverability from various peak supply arrangements.

Off-System Sales

TGI is in its 13^{th} year of off-system sales activities, in which any daily excess supply of gas is sold at the market spot rate and allows for the recovery or mitigation of costs on unutilized supply and/or pipeline capacity. In 2007/2008, TGI marketed approximately 23.5 PJ of surplus gas and 43.7 PJ of excess pipeline capacity for a net pre-tax recovery of approximately $181.5 million. Through the Gas Supply Mitigation Incentive Plan established with the BCUC, $1.1 million (pre-tax) of these benefits accrued to shareholders with the remainder flowing through to customers in the form of reduced natural gas costs.

Unbundling

Over the past several years, TGI, the BCUC and other interested parties have laid the groundwork for the introduction of natural gas commodity unbundling in British Columbia. On November 1, 2004, commercial customers of TGI became eligible to buy their natural gas commodity supply from third-party suppliers. TGI continues to provide delivery of the natural gas. Approximately 80,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2008, approximately 19,800 customers had elected to participate in this program.

During 2006, the BCUC approved the offering of commodity supply choice to residential customers. The BCUC agreed to open a portion of the Province of British Columbia's residential natural gas market to competition, allowing homeowners to sign long-term fixed-price contracts for natural gas with companies other than TGI, effective May 2007. Consumers had the option to remain with TGI or sign with another market participant, in which case they began receiving gas at that market participant's rate beginning in November 2007. TGI continues to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers. Approximately 748,000 residential customers are eligible to participate in commodity unbundling. By December 31, 2008, approximately 115,500 customers had elected to participate in this program. Neither residential nor commercial unbundling has had a material effect on the delivery margins of TGI.

Legal Proceedings

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 taxations years 1999 through 2003. The exposure has been fully provided for in the Corporation's 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 their 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 Corporation's 2008 consolidated financial statements.

Human Resources

At December 31, 2008, the Terasen Gas companies employed 1,260 full-time equivalent employees. Approximately 75 per cent of the employees are represented by IBEW, Local 213 and COPE, Local 378 under collective agreements that expire on March 31, 2011 and March 31, 2012, respectively.

3.2 Regulated Electric Utilities - Canadian

3.2.1 *FortisAlberta*

FortisAlberta is a regulated electric distribution utility in the Province of Alberta. Its business is the ownership and operation of regulated electric distribution facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. FortisAlberta is not involved in the generation, transmission or direct sale of electricity. FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, totalling approximately 108,000 kilometres of distribution lines. The Company's distribution network serves approximately 461,000 customers, comprising residential, commercial, farm and industrial consumers of electricity, and met a peak demand of 3,150 MW in 2008.

Market and Sales

FortisAlberta's annual energy deliveries increased to 15,722 GWh in 2008 from 15,378 GWh in 2007. Revenue was $300 million in 2008 compared to $270 million in 2007.

The following table compares the composition of FortisAlberta's 2008 and 2007 electric rate revenue and energy deliveries by customer class.

FortisAlberta Electric Rate Revenue and Energy Deliveries by Customer Class				
	Revenue *(per cent)*		**GWh Deliveries** [(1)] *(per cent)*	
	2008	2007	**2008**	2007
Residential	**30.5**	30.8	**16.4**	16.2
Large commercial and industrial [(2)]	**22.6**	22.4	**60.9**	60.8
Farms	**12.9**	13.3	**8.2**	8.5
Small commercial	**11.6**	12.0	**8.0**	8.1
Small oil and gas	**9.6**	9.8	**6.0**	6.0
Other [(3)]	**12.8**	11.7	**0.5**	0.4
Total	**100.0**	100.0	**100.0**	100.0

(1) *GWh percentages presented exclude FortisAlberta's GWh deliveries to "transmission-connected" customers. These deliveries consist primarily of large-scale industrial customers directly connected to the transmission grid. The Company collects energy delivery information and discloses it as the volume risk on transmission throughput that resides with the distribution utility. This transmission revenue is recorded net of expenses in other revenue in FortisAlberta's financial statements.*

(2) *Included in the large commercial and industrial customer class are large oil and gas customers*

(3) *Includes revenue from sources other than the delivery of electricity, including that related to street-lighting services, net transmission revenue, rate riders, deferrals and adjustments*

Franchise Agreements

Most of FortisAlberta's residential, commercial and industrial customers located within a city, town, or village boundary are served through franchise agreements between the Company and the customers' municipality of residence. 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 in their municipal boundaries. In Alberta, the standard franchise agreement, which could include a franchise fee payable to the municipality, is generally for ten years and may be renewed for five years upon mutual consent of the parties. All municipal franchises are governed by legislation that requires the municipality or the utility to give notice and obtain AUC approval if it intends to terminate its franchise agreement. Any franchise agreement that is not renewed continues in effect until either the Company or the municipality terminates it with AUC permission. If a franchise agreement is terminated and the municipality subsequently exercises its right under the *Municipal Government Act* (Alberta) to purchase FortisAlberta's distribution network within the municipality's boundaries or annexed area, the Company must be compensated. Compensation would include payment for FortisAlberta's assets on the basis of replacement cost less depreciation.

FortisAlberta serves over 141 municipalities, of which 140 are on standardized individual franchise agreements. Substantially all of these agreements expire between 2011 and 2017. The Company is in the process of renewing or negotiating franchise agreements with one additional municipality and two summer villages.

Human Resources

At December 31, 2008, FortisAlberta had 991 full-time equivalent employees. Approximately 70 per cent of the employees of the Company are members of a labour association represented by UUWA, Local 200, under a three-year collective agreement that expires on December 31, 2010.

3.2.2 *FortisBC*

FortisBC includes FortisBC Inc., an integrated electric utility that owns a network of generation, transmission and distribution assets located in the southern interior of British Columbia. FortisBC Inc. serves a diverse mix of more than 157,000 customers, approximately 110,000 of whom are served directly by the Company's assets while the remainder are served through the wholesale supply of power to municipal distributors. In 2008, FortisBC Inc. met a record peak demand of 746 MW. Residential customers represent the largest customer segment of the Company. FortisBC's transmission and distribution assets include approximately 7,000 kilometres of transmission and distribution lines and 64 distribution substations.

FortisBC also includes operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generation facility owned by Teck Cominco, the 149-MW Brilliant Hydroelectric Plant and 120-MW Brilliant Expansion Plant owned by CPC/CBT, the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT, and the distribution system owned by the City of Kelowna.

Market and Sales

FortisBC has a diverse customer base composed primarily of residential, general service, industrial and municipal wholesale, and other industrial customers. Annual electricity sales were 3,087 GWh in 2008 compared to 3,091 GWh in 2007. Revenue increased to $237 million in 2008 from $229 million in 2007.

The following table compares the composition of FortisBC's 2008 and 2007 revenue and electricity sales by customer class.

FortisBC
Revenue and Electricity Sales by Customer Class

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2008	2007	**2008**	2007
Residential	**43.4**	40.7	**39.5**	37.5
General service	**24.6**	23.6	**23.4**	22.6
Wholesale	**19.3**	19.0	**28.9**	28.5
Industrial	**6.1**	8.4	**8.2**	11.4
Other (1)	**6.6**	8.3	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) Includes revenue from sources other than from the sale of electricity, including revenue of Fortis Pacific Holdings associated with non-regulated operating, maintenance and management services

Generation and Power Supply

FortisBC Inc. meets the electricity supply requirements of its customers through a mix of its own generation and power purchase contracts. FortisBC Inc. owns four regulated hydroelectric generating plants on the Kootenay River with an aggregate capacity of 223 MW and annual energy output of approximately 1,591 GWh, which provide approximately 45 per cent of the Company's energy needs and 30 per cent of its capacity needs. FortisBC Inc. meets the balance of its requirements through a portfolio of long-term and short-term power purchase contracts.

FortisBC Inc.'s four hydroelectric generation facilities are governed by the CPA. The CPA is a multi-party agreement that enables the five separate owners of eight major hydroelectric generating plants, with a combined capacity of more than 1,500 MW and located in relatively close proximity to each other, to coordinate the operation and dispatch of their plants.

The following table lists the plants and their owners.

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	450	Teck Cominco
Kootenay River System	223	FortisBC Inc.
Brilliant Dam and Expansion	269	BPC and BEPC
Total	**1,522**	

BPC, BEPC, Teck Cominco and FortisBC Inc. are collectively defined in the CPA as the Entitlement Parties. The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows, subject to the 1961 Columbia River Treaty between Canada and the United States, and storage reservoirs, and through the coordinated operation of generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by all seven plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these facilities, each of the Entitlement Parties is contractually entitled to a fixed annual entitlement of capacity and energy from BC Hydro, which is currently based on 50-year historical water flows. The Entitlement Parties receive their defined entitlements irrespective of actual water flows to the Entitlement Parties' generating plants and are, accordingly, insulated from the risk of water availability.

The majority of FortisBC Inc.'s remaining electricity supply is acquired through long-term power purchase contracts, consisting of the following:

i. a 149-MW long-term power purchase agreement with BPC terminating in 2056;
ii. a 200-MW power purchase agreement with BC Hydro terminating in 2013; and
iii. a number of small power purchase contracts with independent power producers.

The majority of these purchase contracts have been approved by the BCUC and prudently incurred costs thereunder flow through to customers through FortisBC Inc.'s electricity rates.

Although FortisBC Inc. can currently meet most of its customer supply requirements from its own generation and the long-term power purchase agreements described above, a portion of the customer load during the summer and winter peak-demand periods may need to be supplied from the market in the form of short-term power purchases. Costs related to such purchases, provided they are prudently incurred and accurately forecasted, are largely flowed through to customers. FortisBC Inc. generally makes arrangements prior to the winter season to acquire power at known prices should the need arise.

Legal Proceedings

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 Corporation's 2008 consolidated financial statements.

Human Resources

At December 31, 2008, FortisBC had 545 full-time equivalent employees. FortisBC had a collective agreement with IBEW, Local 213, which expired on January 31, 2009, and a collective agreement with COPE, Local 378, expiring on January 31, 2011. The two collective agreements cover approximately 75 per cent of employees. A new four-year collective agreement with IBEW, Local 213, was ratified by the union in February 2009.

3.2.3 *Newfoundland Power*

Newfoundland Power is the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 236,000 customers, or 85 per cent of the Province's electricity consumers. Newfoundland Power met a peak demand of 1,181 MW in 2008. The balance of the population is served by Newfoundland's other electric utility, Newfoundland Hydro, which also serves several larger industrial customers. Newfoundland Power owns and operates approximately 11,000 kilometres of transmission and distribution lines.

Market and Sales

Annual weather-adjusted electricity sales increased to 5,208 GWh in 2008 from 5,093 GWh in 2007. Revenue increased to $517 million in 2008 from $491 million in 2007.

The following table compares the composition of Newfoundland Power's 2008 and 2007 revenue and electricity sales by customer class.

Newfoundland Power
Revenue and Electricity Sales by Customer Class

	Revenue [(1)] *(per cent)*		**GWh Sales** [(1)] *(per cent)*	
	2008	2007	**2008**	2007
Residential	**58.9**	58.5	**60.1**	59.8
Commercial and Street Lighting	**37.3**	38.5	**39.9**	40.2
Other [(2)]	**3.8**	3.0	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

[(1)] *Revenue and electricity sales reflect weather-adjusted values pursuant to Newfoundland Power's weather normalization reserve.*
[(2)] *Includes revenue from sources other than from the sale of electricity, the most significant being joint-use of pole revenue*

Power Supply

Approximately 92 per cent of Newfoundland Power's energy requirements is purchased from Newfoundland Hydro. The principal terms of the supply arrangements with Newfoundland Hydro are regulated by the PUB on a basis similar to that upon which Newfoundland Power's service to its customers is regulated.

Newfoundland Power operates 30 small generating stations which generate approximately 8 per cent of the electricity sold by Newfoundland Power. The Company's hydroelectric generating plants have a total capacity of 97 MW. The diesel plants and gas turbines have a total capacity of approximately 7 MW and 36 MW, respectively.

The City of St. John's has given formal notice of its intention to terminate Newfoundland Power's rights to use the Mobile River watershed for the generation of electricity. The effective date of the notice to terminate the lease was March 1, 2009. The Company held these rights under a lease dated November 23, 1946, which was amended by an agreement dated October 21, 1949. The two hydroelectric generating plants affected by the lease have a combined capacity of approximately 12 MW and generate annual production of 49 GWh, representing less than one per cent of the Company's total energy requirements. To exercise the termination provision of the lease, the City of St. John's is required to pay to the Company the value of all works and erections employed in the generation and transmission of electricity using the water of the Mobile River watershed. In accordance with the terms of the lease, an arbitration panel was appointed in 2008 for the purpose of determining the value of the affected assets. On March 9, 2009, the panel issued a ruling on certain preliminary questions. A majority of the panel ruled that termination of the lease will not be effective until payment to the Company of the value of the assets, and that the value payment is to be based on a valuation of the assets as a going concern, including the land and water rights. The ruling is subject to judicial review.

Human Resources

At December 31, 2008, Newfoundland Power had 551 full-time equivalent employees of which approximately 54 per cent were members of bargaining units represented by IBEW, Local 1620.

In September 2008, two collective agreements governing Newfoundland'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.

3.2.4 *Other Canadian Electric Utilities*

Other Canadian Electric Utilities includes the operations of Maritime Electric and FortisOntario.

Maritime Electric

The Corporation, through Fortis Properties, holds all of the common shares of Maritime Electric. Maritime Electric operates an integrated electric utility which directly supplies approximately 73,000 customers, constituting 90 per cent of electricity consumers on Prince Edward Island. Maritime Electric purchases most of the energy it distributes to its customers from NB Power, a provincial Crown Corporation. Maritime Electric's system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick, which are leased from the Government of Prince Edward Island. Maritime Electric owns and operates generating plants with a combined capacity of 150 MW on Prince Edward Island and met a peak demand of 223 MW in 2008. Maritime Electric owns and operates approximately 5,300 kilometres of transmission and distribution lines.

FortisOntario

The Corporation's wholly owned regulated utility investments in Ontario, collectively FortisOntario, are composed of Canadian Niagara Power, including the operations of Port Colborne Hydro, and Cornwall Electric. Canadian Niagara Power services Fort Erie, Port Colborne and Gananoque, while Cornwall Electric services Cornwall. In total, FortisOntario's distribution operations serve approximately 52,000 customers. Canadian Niagara Power owns international transmission facilities at Fort Erie, Ontario and owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence, two regional electric distribution companies formed in 2000. FortisOntario met a combined peak demand of 227 MW in 2008. FortisOntario owns and operations approximately 1,570 kilometres of transmission and distribution lines.

Market and Sales

Annual electricity sales were 2,182 GWh in 2008 compared to 2,209 GWh in 2007. Revenue was $262 million in 2008 compared to $263 million in 2007.

The following table compares the composition of Other Canadian Electric Utilities' 2008 and 2007 revenue and electricity sales by customer class.

Other Canadian Electric Utilities Revenue and Electricity Sales by Customer Class				
	Revenue *(per cent)*		GWh Sales *(per cent)*	
	2008	2007	**2008**	2007
Residential	**43.4**	44.0	**42.4**	42.1
Commercial and industrial	**49.3**	49.8	**57.3**	57.6
Other [(1)]	**7.3**	6.2	**0.3**	0.3
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes revenue from sources other than from the sale of electricity*

Power Supply

Maritime Electric

Maritime Electric purchased more than 87 per cent of the electricity required to meet its customers' needs from NB Power in 2008. The balance was met through Maritime Electric's on-Island generation facilities and the purchase of wind energy produced on Prince Edward Island. Maritime Electric's generation facilities have a total installed capacity of 150 MW and are used primarily for peaking, submarine-cable loading issues and emergency purposes.

In 2008, approximately 5 per cent of the energy that Maritime Electric purchased from NB Power came from the Point Lepreau Station. The Point Lepreau Station began a major refurbishment in 2008 that will extend its estimated life to 2035. The cost of replacement energy during the refurbishment of the Point Lepreau Station is expected to be recovered from customers through the operation of the ECAM. To date, replacement costs for 2008 are being collected and costs for 2009 have been approved for deferral for future collection from customers, as approved by IRAC.

Legislation proclaimed by the Government of Prince Edward Island will see an increased reliance by Maritime Electric on renewable energy sources, such as wind-powered energy, located on Prince Edward Island. By 2013, Maritime Electric will be required to have a total of 30 per cent of its annual energy requirements from on-Island wind farms. In 2006, the Company signed an agreement with PEI Energy Corporation which will see the Company purchase 39 MW of wind-powered energy from PEI Energy Corporation's new wind farm. In 2008, 13 per cent of the Island's energy-supply requirements were generated by wind.

FortisOntario

The power requirements of FortisOntario's service areas are provided from various sources. Canadian Niagara Power purchases its power requirements for Fort Erie and Port Colborne from the IESO. Under the Standard Supply Code of the OEB, Canadian Niagara Power is obliged to provide Standard Service Supply to all its customers who do not choose to contract with an electricity retailer. This energy is provided to customers at either regulated or market prices.

Canadian Niagara Power purchases approximately 83 per cent of energy requirements for Gananoque through monthly energy purchases from Hydro One and the remaining 17 per cent is purchased from six hydroelectric generating plants owned by Fortis Properties.

Cornwall Electric purchases 100 per cent of its power requirements from Hydro-Québec Energy Marketing under two fixed-term contracts. The first contract, which represents approximately 37 per cent of the power supply, is a 45-MW contract with a 60 per cent capacity factor. The second contract, supplying the remainder of Cornwall Electric's energy requirement, is a 100-MW capacity and energy contract. Both contracts expire in December 2019.

Legal Proceedings

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 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.

Human Resources

At December 31, 2008, Maritime Electric had 179 full-time equivalent employees, of which approximately 70 per cent were represented by IBEW, Local 1432. The collective agreement with IBEW, Local 1432, expired on December 31, 2008. Maritime Electric and IBEW are currently negotiating a new collective agreement.

At December 31, 2008, FortisOntario had 125 full-time equivalent employees, of which approximately 64 per cent were represented by CUPE, Local 137, and IBEW, Local 636, in the Niagara Region and IBEW, Local 636, in Gananoque. The collective agreements governing these employees expire on April 30, 2009, May 31, 2009 and July 31, 2009, respectively.

3.3 Regulated Electric Utilities - Caribbean

Regulated Electric Utilities - Caribbean operations are comprised of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos.

Belize Electricity, the principal distributor of electricity in Belize, Central America, serves approximately 74,000 customers, owns approximately 2,840 kilometres of transmission and distribution lines and met a peak demand of 74 MW in 2008. The Corporation holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 24,000 customers. The Company met a record peak demand of 94 MW in 2008. Caribbean Utilities owns and operates approximately 555 kilometres of transmission and distribution lines. 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 has 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 its financial results.

Fortis Turks and Caicos, wholly owned by Fortis, serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands and met a peak demand of 29 MW in 2008. Fortis Turks and Caicos owns and operates approximately 335 kilometres of transmission and distribution lines. The Company is the principal distributor of electricity on the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Market and Sales

Annual electricity sales increased to 1,199 GWh in 2008 from 1,054 GWh in 2007. Annual revenue increased to $408 million in 2008 from $307 million in 2007.

The following table compares the composition of Regulated Electric Utilities - Caribbean's revenue and electricity sales by customer class for the years ended 2008 and 2007.

Regulated Electric Utilities – Caribbean *(1) (2)*
Revenue and Electricity Sales by Customer Class

	Revenue *(3)* *(per cent)*		**GWh Sales** *(3)* *(per cent)*	
	2008	2007	**2008**	2007
Residential	**46.8**	47.5	**47.2**	48.4
Commercial, industrial and street lighting	**51.9**	51.2	**52.8**	51.6
Other *(4)*	**1.3**	1.3	**-**	-
Total	**100.0**	100.0	**100.0**	100.0

(1) *Includes Caribbean Utilities, Fortis Turks and Caicos, and Belize Electricity*
(2) *Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial results were consolidated in the financial statements of Fortis on a two-month lag. Caribbean Utilities changed it fiscal year end to December 31 which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Revenue and GWh sales above include 14 months of data for Caribbean Utilities.*
(3) *The 2008 and 2007 figures are for the periods ended December 31, 2008 and 2007, respectively, and include 100 per cent of the revenue and electricity sales of Caribbean Utilities, Fortis Turks and Caicos, and Belize Electricity.*
(4) *Includes revenue from sources other than from the sale of electricity*

Power Supply

In 2008, 67 per cent of the electricity needs of Regulated Electric Utilities - Caribbean were produced from gas and diesel-fired generation. The majority of the remainder was produced from hydroelectric generating facilities in Belize and purchased from CFE.

Belize Electricity meets its energy demand from multiple sources, which include power purchases from: (i) CFE, the Mexican state-owned power company; (ii) the Mollejon and Chalillo hydroelectric generating facilities owned and operated by BECOL; (iii) the Hydro Maya hydroelectric generating plant owned by Hydro Maya Limited; and (iv) its own diesel-fired and gas turbine generation. All major load centers are connected to Belize's national electricity system, which is connected with the Mexican national electricity grid, allowing Belize Electricity to optimize its power supply options. Belize Electricity purchased and produced 464 GWh of electricity in 2008, of which 98 per cent was purchased from CFE, the Mollejon and Chalillo hydroelectric generating facilities, and Hydro Maya Limited. The balance was produced by Belize Electricity's installed generating capacity of 34 MW, including a 23-MW gas-turbine generating facility.

Caribbean Utilities relies upon diesel-fired generation to produce electricity for Grand Cayman. Grand Cayman has neither hydroelectric potential nor inherent thermal resources and the Company must rely upon diesel fuel imported to Grand Cayman primarily from refineries in the Caribbean and the Gulf of Mexico. The Company has an installed generating capacity of approximately 137 MW.

Fortis Turks and Caicos relies upon diesel-fired generation, which has a combined generating capacity of 48 MW, to produce electricity for its customers.

Legal Proceedings

Belize Electricity is involved in a number of legal proceedings relating to the PUC's Final Decision on Belize Electricity's 2008/2009 Rate Application. For further information, refer to the "Material Regulatory Decisions and Applications" in section 4.0, "Regulation", of this 2008 Annual Information Form.

Human Resources

At December 31, 2008, Regulated Electric Utilities - Caribbean employed 570 full-time equivalent employees. The 197 employees at Caribbean Utilities and 95 employees at Fortis Turks and Caicos are non-unionized. Of the 278 full-time equivalent employees at Belize Electricity, approximately 59 per cent were represented by BEWU. The Company's collective agreement with BEWU was signed in July 2008 and is to be reviewed every five years.

3.4 Non-Regulated – Fortis Generation

The following table summarizes the Corporation's non-regulated generation assets by location.

Fortis Generation
Non-Regulated Generation Assets

Location	Plants	Fuel	Capacity (MW)
Belize [(1)]	2	hydro	32
Ontario	8	hydro, thermal	88
Central Newfoundland	2	hydro	36
British Columbia	1	hydro	16
Upper New York State	4	hydro	23
Total	**17**		**195**

(1) *Construction of a third plant, the 19-MW Vaca hydroelectric generating facility, commenced in 2007 and is expected to come into service at the beginning of 2010.*

The Corporation's non-regulated generation operations consist of its 100 per cent ownership interest in each of BECOL, FortisOntario Inc. and FortisUS Energy, as well as non-regulated generation assets owned by Fortis Properties and FortisBC Inc.

Non-regulated generation operations in Belize consist of the operations of the 25-MW Mollejon and the 7-MW Chalillo hydroelectric generating facilities. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055 and a franchise agreement with the Government of Belize. Under these agreements, the Mollejon hydroelectric generating facility will be transferred to the Government of Belize in 2036, after which it will be leased at an annually increasing rate for a term expiring in 2055.

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 generation facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Belize Electricity has signed a 50-year power purchase agreement for the purchase of the energy to be generated by the Vaca facility. At December 31, 2008, approximately $32 million (US$30 million) was incurred under this project.

Non-regulated generation operations of FortisOntario Inc. include 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires on April 30, 2009, and the operation of a 5-MW gas-fired cogeneration plant in Cornwall.

Fortis Properties, a non-regulated wholly owned subsidiary, holds a 51 per cent interest in the Exploits Partnership, the Corporation's non-regulated generation operations in central Newfoundland. The Exploits Partnership was established with Abitibi-Consolidated, which holds the remaining 49 per cent interest, to develop additional capacity at Abitibi-Consolidated's hydroelectric generating plant at Grand Falls-Windsor, Newfoundland and Labrador and redevelop Abitibi-Consolidated's hydroelectric generating plant at Bishop's Falls, Newfoundland and Labrador. These operations generate approximately 610 GWh annually, of which 470 GWh is utilized by Abitibi-Consolidated, while the remainder is sold to Newfoundland Hydro under a 30-year take-or-pay power purchase agreement, expiring in 2033, which is exempt from regulation. The assets of Fortis Properties also consist of six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

The non-regulated generation operations of FortisBC Inc., conducted through Walden, its wholly owned partnership, consist of the 16-MW run-of-river hydroelectric generating plant near Lillooet, British Columbia. This plant is a non-regulated operation that sells its entire output to BC Hydro under a power purchase agreement expiring in 2013.

Through FortisUS Energy, an indirect wholly owned subsidiary, the Corporation owns and operates four hydroelectric generating stations in Upper New York State with a combined capacity of approximately 23 MW operating under licences from FERC. All four hydroelectric generating stations sell energy at current market rates.

Market and Sales

Annual energy sales from non-regulated generation assets were 1,217 GWh in 2008 compared to 1,122 GWh in 2007. Revenue was $82 million in 2008 compared to $75 million in 2007.

The following table compares the composition of Fortis Generation's 2008 and 2007 revenue and energy sales by location.

Fortis Generation
Revenue and Energy Sales by Location

	Revenue *(per cent)*		**GWh Sales** *(per cent)*	
	2008	2007	**2008**	2007
Belize	**20.8**	21.2	**15.8**	14.9
Ontario	**42.7**	46.4	**58.8**	63.0
Central Newfoundland	**25.6**	23.0	**14.6**	12.2
British Columbia	**2.2**	2.3	**2.7**	3.0
Upper New York State	**8.7**	7.1	**8.1**	6.9
Total	**100.0**	100.0	**100.0**	100.0

Legal Proceedings

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, 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 Corporation's 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.

Human Resources

At December 31, 2008, Fortis Generation employed 26 full-time equivalent personnel, none of whom participate in a collective agreement.

3.5 Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels with more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada. As a wholly owned subsidiary of Fortis, Fortis Properties is the Corporation's vehicle for non-utility diversification and growth.

Revenue was $207 million in 2008 compared to $191 million in 2007. In 2008, Fortis Properties derived approximately 30 per cent of its revenue from real estate operations and 70 per cent of its revenue from hotel operations. Fortis Properties derived approximately 43 per cent of its 2008 operating income from real estate operations and 57 per cent from hotel operations.

Fortis Properties' Real Estate Division is anchored by high-quality tenants under long-term leases. The Real Estate Division ended 2008 with 96.8 per cent occupancy, consistent with the rate at the end of 2007. In contrast, the average national occupancy rate was 93.3 per cent at the end of 2008 compared to 93.8 per cent at the end of 2007.

The following table sets out the office and retail properties owned by Fortis Properties.

Fortis Properties Office and Retail Properties			
Property	**Location**	**Type of Property**	**Gross Lease Area** *(square feet 000s)*
Fort William Building	St. John's, NL	Office	188
Cabot Place I	St. John's, NL	Office	135
TD Place	St. John's, NL	Office	94
Fortis Building	St. John's, NL	Office	83
Multiple Office	St. John's, NL	Office and Retail	75
Millbrook Mall	Corner Brook, NL	Retail	118
Fraser Mall	Gander, NL	Retail	99
Marystown Mall	Marystown, NL	Retail	87
Fortis Tower	Corner Brook, NL	Office	69
Viking Mall	St. Anthony, NL	Retail	69
Maritime Centre	Halifax, NS	Office and Retail	564
Brunswick Square	Saint John, NB	Office and Retail	512
Kings Place	Fredericton, NB	Office and Retail	292
Blue Cross Centre	Moncton, NB	Office and Retail	324
Delta Regina	Regina, SK	Office	52
Total			**2,761**

The Hospitality Division of Fortis Properties achieved higher revenue per available room for the 13th consecutive year increasing to $80.39 in 2008 from $79.31 in 2007. This increase was the result of improvements in average room rates in 2008, partially offset by lower average occupancy. The average daily rate increased to $120.23 in 2008 from $115.67 in 2007, while average occupancy for 2008 was 66.9 per cent, lower than the 68.6 per cent achieved in 2007.

In November 2008, Fortis Properties acquired the Fairmont Newfoundland hotel, increasing hospitality operations by 301 rooms and 16,000 square feet of convention space. The Fairmont Newfoundland hotel was rebranded the Sheraton Hotel Newfoundland in January 2009.

The hotels owned and managed by Fortis Properties are summarized as follows.

Fortis Properties Hotels			
Hotels	**Location**	**Number of Guest Rooms**	**Conference Facilities** *(square feet 000's)*
Delta St. John's	St. John's, NL	403	21
Holiday Inn St. John's	St. John's, NL	252	11
Sheraton Hotel Newfoundland [(1)]	St. John's, NL	301	16
Mount Peyton	Grand Falls-Windsor, NL	149	4
Greenwood Inn Corner Brook	Corner Brook, NL	102	5
Four Points by Sheraton Halifax	Halifax, NS	177	12
Delta Sydney	Sydney, NS	152	6
Delta Brunswick	Saint John, NB	254	18
Holiday Inn Kitchener-Waterloo	Kitchener-Waterloo, ON	184	13
Holiday Inn Peterborough	Peterborough, ON	153	7
Holiday Inn Sarnia	Point Edward, ON	217	11
Holiday Inn Cambridge	Cambridge, ON	143	7
Greenwood Inn Calgary	Calgary, AB	210	9
Greenwood Inn Edmonton	Edmonton, AB	224	8
Greenwood Inn Winnipeg	Winnipeg, MB	213	10
Ramada Hotel & Suites Lethbridge	Lethbridge, AB	119	5
Holiday Inn Express and Suites Medicine Hat	Medicine Hat, AB	93	1
Best Western Medicine Hat	Medicine Hat, AB	122	-
Holiday Inn Express Kelowna	Kelowna, BC	120	-
Delta Regina	Regina, SK	274	24
Total		**3,862**	**188**

[(1)] *Formerly Fairmont Newfoundland*

Human Resources

At December 31, 2008, Fortis Properties employed approximately 2,000 full-time equivalent employees, approximately 52 per cent of whom are represented by unions listed in the following table.

Fortis Properties Unions			
Property	**Union**	**Expiry of Agreement**	**Number of Unionized Employees**
Holiday Inn St. John's	CAW	August 31. 2009	53
Delta St. John's	UFCW	December 31, 2009	239
Greenwood Inn Corner Brook	CAW	March 11, 2010	41
East Side Mario's St. John's	CAW	July 31, 2010	80
Delta Sydney	CAW	September 30, 2008 [(1)]	81
Delta Brunswick & Brunswick Square	USW	June 10, 2010	133
Delta Regina	CEP	November 30, 2010	168
St. John's Real Estate	IBEW	April 17, 2010	11
Sheraton Newfoundland [(2)]	CAW	March 31, 2011	182
Mount Peyton	UFCW	December 1, 2011	45
Total			**1,033**

[(1)] *Delta Sydney has commenced union contract negotiations.*
[(2)] *Formerly Fairmont Newfoundland*

4.0 REGULATION

The nature of regulation and a 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			COS/ROE PBR mechanism through 2009: TGI:50/50 sharing of earnings above or below the allowed ROE 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
TGI	BCUC	35	8.37	8.62	8.47	
TGVI	BCUC	40	9.07	9.32	9.17	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	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	IRAC	40	10.25	10.00	9.75	COS/ROE Future Test Year
FortisOntario	OEB (Canadian Niagara Power) Franchise Agreement (Cornwall Electric)	43.3 (2)	9.00	9.00	8.39	Canadian Niagara Power - COS/ROE Cornwall Electric - Price cap with commodity cost flow through Future Test Year – beginning in 2009
			ROA			
Belize Electricity	PUC	N/A	10.00 - 15.00	10.00	10.00 (3)	Four-year COS/ROA agreements 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	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 CPI for British Columbia minus a 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 (continued)	
Regulated Utility	**Summary Description**
FortisAlberta (continued)	• 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 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 Station replacement energy costs for 2009 and an increase in the amortization 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 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. • 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.

Material Regulatory Decisions and Applications (continued)	
Regulated Utility	**Summary Description**
FortisOntario (continued)	• 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 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 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 (continued)	
Regulated Utility	**Summary Description**
Caribbean Utilities	• In December 2007, an 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 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 totaling 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.

5.0 ENVIRONMENTAL MATTERS

The Corporation and its Canadian subsidiaries are subject to federal, provincial and municipal laws, regulations and guidelines relating to the protection of the environment including, but not limited to, wildlife, water and land protection and the proper storage, transportation, recycling and disposal of hazardous and non-hazardous substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after their commencement.

Several key Canadian federal environmental laws and regulations affecting the operations of the Corporation's Canadian subsidiaries include, but are not limited to, the (i) *Canadian Environmental Assessment Act;* (ii) *Canadian Environmental Protection Act*; (iii) *Transportation of Dangerous Goods Act and Regulations*; (iv) *Hazardous Product Act*; (v) *Canada Wildlife Act*; (vi) *Navigable Waters Protection Act*; (vii) *Canada National Parks Act*; (viii) *Fisheries Act; (ix) Canada Water Act; (x) National Emission Guidelines for Stationary Combustion Turbines; (xi) National Fire Code of Canada; (xii) Pest Control Products Act and Regulations; (xiii) Storage of PCB Material Regulations; (xiv) Canadian Species at Risk Act; and (xv) Ozone Depleting Substances Regulations.*

There are many Canadian provincial and municipal laws, regulations and guidelines that address similar environmental risks as the federal laws, regulations and guidelines, but at a local level.

In British Columbia, the *Carbon Tax Act* and *Greenhouse Gas Reduction Targets Act* specifically affect, or may potentially affect, the operations of the Terasen Gas companies and FortisBC as is described later.

While there are environmental laws, regulations and guidelines affecting the Corporation's operations in Grand Cayman and Turks and Caicos, and Belize, they are less extensive than the laws, regulations and guidelines in Canada.

Environmental risks affecting the Corporations' utility operations include, but are not limited to: (i) hazards associated with the storage and handling of large volumes of fuel at fuel-fired electricity generating plants, including leeching of the fuel into the ground and nearby watershed areas; (ii) risk of spilling or leaking petroleum-based products, including PCB-contaminated oil, which are used in the cooling and lubrication of transformers, capacitors and other electrical equipment; (iii) greenhouse gas emissions, including natural gas and propane leaks and spills and emissions from the combustion of fuel required to generate electricity; (iv) risk of fire; (v) risk of contamination of air, soil or land associated with the improper handling, storage, transportation and disposal of other hazardous substances; (vi) risk of disruption to vegetation; (vii) risk of contamination of soil and water near chemically treated poles; (viii) risk of disruption to fish, animals and their habitat as a result of the creation of artificial water flows and levels associated with hydroelectric water storage and utilization; and (ix) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner.

The key focus of the utilities is to provide reliable cost-effective service with full regard for the safety of employees and the public while operating in an environmentally responsible manner. A focus on safety and the environment is, therefore, an integral and continuing component of the Corporation's operating activities. The environmental policies vary among the Corporation's utilities depending on the specific environmental laws, regulations and guidelines applicable to their operations and jurisdiction. However, the policies are implemented and reinforced through the use of environmental management systems. Common elements of the utilities' environmental management systems include: (i) regular inspections of fuel and oil-filled equipment in order to identify and correct for potential spills, and spill response systems to ensure that all spills are addressed, and the associated cleanup is conducted in a prompt and environmentally responsible manner; (ii) greenhouse gas emissions management; (iii) procedures for handling, transporting, storing and disposing of hazardous substances, including chemically treated poles, asbestos, lead and mercury; (iv) programs to mitigate fire-related incidents; (v) programs for the management and/or elimination of PCBs; (vi) vegetation management programs; (vii) training of and communicating of environmental policies to employees to ensure work is conducted in an environmentally responsible manner; (viii) review of work practices that affect the environment; (ix) waste management programs; (x) environmental emergency response procedures; (xi) environmental site assessments; and (xii) environmental incident reporting procedures.

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario have developed their respective environmental management systems consistent with the guidelines of ISO 14001, an internationally recognized standard for environmental management systems. Caribbean Utilities operates an environmental management system associated with its generation operations, which is ISO 14001 certified, and uses an environmental management system for its transmission and distribution operations, which is consistent with ISO 14001 guidelines. Belize Electricity has implemented an environmental management system with the intention of it becoming consistent with ISO 14001 guidelines by the end of 2010. Fortis Turks and Caicos plans to implement an environmental management system in 2009 that will be consistent with ISO 14001 standard by 2012. As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor performance. External and internal audits of the environmental management systems are performed on a periodic basis. Based on audits completed in 2008, the environmental management systems continue to be effective and materially consistent with ISO 14001 guidelines. In 2008, an external audit conducted on Caribbean Utilities' environmental management system associated with its generation operations verified the system remained ISO 14001 certified.

Environmental risks associated with the Corporation's non-regulated generation operations are either addressed by environmental management systems of the Corporation's regulated electric utilities or by environmental practices and procedures followed by Fortis Properties.

For the Corporation's regulated gas utilities, air emissions management is the main environmental concern primarily due to the uncertainties relating to emerging federal and provincial greenhouse gas regulations. While governmental policy direction is starting to unfold, it remains to be determined to what extent a greenhouse air emissions cap will impact these utilities. To mitigate this uncertainty, the Terasen Gas companies participate in sectoral and industry groups to help develop the emerging regulation. In addition, TGI was an active participant in Canada's Voluntary Climate Change Challenge and Registry and, its successor, the Canadian Greenhouse Gas Challenge Registry.

Recent updates to the Government of British Columbia's Energy Plan and greenhouse gas reduction targets present risks and opportunities to the Terasen Gas companies and, to a lesser degree, FortisBC. The *Greenhouse Gas Reduction Targets Act* mandates a province-wide reduction in greenhouse gases of 33 per cent from 2007 levels. This is coupled with mandates for all new electricity generation to be net carbon neutral, and for British Columbia to be electrically self-sufficient by 2016.

Energy and emissions policies in British Columbia also present a number of opportunities. The policies have created incentives to expand Terasen's deployment of renewable energy, such as biogas, and to expand the Company's Energy Efficiency and Conservation Program. Additionally, the introduction of the *Carbon Tax Act* improves the position of natural gas relative to other fossil energy, as the tax is based on the amount of carbon dioxide equivalent emitted per unit energy. Natural gas, therefore, has a lower tax rate than oil or coal products.

British Columbia is a participant in the Western Climate Initiative. The participants, consisting of several states and provinces, plan to implement a cap-and-trade program to reduce greenhouse gas emissions. The program begins on January 1, 2012. At that time, Terasen expects to have one facility, the Terasen Gas (Vancouver Island) Inc. transmission system, covered under the program. This facility will be required to reduce emissions to meet a declining cap on emissions, or to purchase emissions allowances to cover emissions over the capped amount. While allowance costs are based on market prices that have little clarity at present, it appears likely that this facility will be a net purchaser of allowances over the near and medium term. Allowances will likely be issued to mirror the emission reduction mandate of the Government of British Columbia, such that emissions will need to be reduced by 33 per cent over 2007 amounts by 2020.

The key environmental risks affecting the Corporation's hospitality and real estate operations include, but are not limited to: (i) risk of asbestos and urea-formaldehyde contamination in buildings; (ii) risk of release of ozone-depleting substances from air conditioning and refrigeration equipment; (iii) fuel tank leaks; and (iv) risk of responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. Fortis Properties is committed to meeting the requirements of environmental standards related to its hospitality and real estate operations. In assessing new properties, all buildings and hotels must meet environmental standards, including, but not limited to, the appropriate federal, provincial and municipal standards for asbestos, fuel storage, urea-formaldehyde and chlorofluorocarbon-based refrigerants in air conditioning and refrigerating equipment. This process is also applied to existing properties, ensuring environmental compliance by all facilities.

The Corporation has asset-retirement obligations as disclosed in the Notes to the 2008 consolidated financial statements of Fortis. However, liabilities with respect to these asset retirements obligations have not been recorded in the Corporation's 2008 Consolidated Financial Statements as they could not be reasonably estimated or were determined to be immaterial (including asset retirement obligations associated with PCBs, asbestos and chemically treated poles) to the Corporation's consolidated results of operations, cash flows or financial position.

Costs associated with environmental protection initiatives (including the development, implementation and maintenance of environmental management systems), compliance with environmental laws, regulations and guidelines, and environmental damage were not material to the Corporation's consolidated results of operations, cash flows or financial position and, based on current laws, facts and circumstances, are not expected to have a material effect in the future. At the Corporation's regulated utilities, prudently incurred operating and capital costs associated with environmental protection initiatives, compliance with environmental laws, regulations and guidelines, and environmental damage are eligible for recovery in customer rates. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws and regulations applicable to them in the various jurisdictions in which they operate.

6.0 RISK FACTORS

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 - 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 regulatory approvals 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 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 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 impacts of interest rates on allowed ROEs is provided in the "Risk Factors – Interest Rate Risk" section of this 2008 Annual Information Form.

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. For further information on FortisBC's PBR mechanism, refer to "Material Regulatory Decisions and Applications" in section 4.0, "Regulation", of this 2008 Annual Information Form.

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 "Risks Factors – Insurance Coverage Risk" section of this 2008 Annual Information Form 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. 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 are 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.

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 transmission and distribution assets. In Belize, additional costs in the event of a hurricane would be deferred and

Belize Electricity may apply for future recovery in customer rates. Under its new transmission and distribution 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 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 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 expense resulting from fluctuations in interest rates associated with variable rate debt for recovery from, or refund to, customers in future rates. 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 the low notional value of the interest rate swaps and their near-term maturities.

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 "Risk Factors – Economic Conditions" section of this 2008 Annual Information Form.

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 "Risk Factors – Risks Related to TGVI" and "Risk Factors – Government of British Columbia's Energy Plan" sections of this 2008 Annual Information Form.

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. 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.

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. 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 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 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 "Risks Factors – Insurance Coverage Risk" section of this 2008 Annual Information Form.

The Corporation's utilities address environmental matters in their operations through the use of environmental management systems. As part of their respective environmental management systems, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' transmission and distribution 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 A*ct (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 IFRS: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt IFRS as issued by the International Accounting Standards Board. 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.

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 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 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. 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 Utilities Corporation and may not be able 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.

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.

7.0 GENERAL DESCRIPTION OF SHARE CAPITAL STRUCTURE

The authorized share capital of the Corporation consists of the following:

(a) an unlimited number of Common Shares without nominal or par value;
(b) an unlimited number of First Preference Shares without nominal or par value; and
(c) an unlimited number of Second Preference Shares without nominal or par value.

At March 12, 2009, the following Common Shares and First Preference Shares were issued and outstanding.

Share Capital	Issued and Outstanding	Votes per Share
Common Shares	169,758,654	One
First Preference Shares, Series C	5,000,000	None
First Preference Shares, Series E	7,993,500	None
First Preference Shares, Series F	5,000,000	None
First Preference Shares, Series G	9,200,000	None

The following table summarizes the cash dividends declared per share for each of the Corporation's class of share for the past three years.

	Dividends Declared *(per share)*		
Share Capital	**2006**	**2007**	**2008**
Common Shares	$0.70	$0.88	$1.01
First Preference Shares, Series C	$1.3625	$1.3625	$1.3625
First Preference Shares, Series E	$1.2250	$1.2250	$1.2250
First Preference Shares, Series F (1)	$0.5211	$1.2250	$1.2250
First Preference Shares, Series G (2)	-	-	$1.0184

(1) The First Preference Shares, Series F were issued in September 2006.

(2) The First Preference Shares, Series G were issued in May and June 2008.

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.

On December 10, 2008, the Board declared an increase in the regular quarterly dividend to $0.26 per Common Share, with the first payment occurring on March 1, 2009, which was paid to holders of record on February 6, 2009. Also on December 10, 2008, the Board declared a first quarter 2009 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate and was paid to holders of record on February 6, 2009.

On March 11, 2009, the Board declared a second quarter 2009 dividend of $0.26 per Common Share and a second quarter 2009 dividend on the First Preference Shares, Series C, E, F and G in accordance with the applicable annual prescribed rate. In each case, the second quarter 2009 dividends will be paid on June 1, 2009 to holders of record on May 8, 2009.

Common Shares

Dividends on Common Shares are declared at the discretion of the Board. Holders of Common Shares are entitled to dividends on a pro rata basis if, as, and when declared by the Board. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the Board may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares.

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any other class or series of shares, and are entitled to one vote in respect of each Common Share held at such meetings.

First Preference Shares, Series C

The 5,000,000 First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of $1.3625 per share per annum. On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time, or in part from time to time, at $25.75 per share if redeemed before June 1, 2011; at $25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012; at $25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013; and at $25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time, any part of the outstanding First Preference Shares, Series C 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 Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of $1.00 and 95 per cent of the then-current market price of the Common Shares. On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, 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 elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series E

The 7,993,500 First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to $25.75 if redeemed during the 12 months commencing June 1, 2013; $25.50 if redeemed during the 12 months commencing June 1, 2014; $25.25 if redeemed during the 12 months commencing June 1, 2015; and $25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption. On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E 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, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, 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, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradable Common Shares determined by dividing $25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, 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 E elects to convert any of such shares into Common Shares, the Corporation can redeem such First Preference, Shares E for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares, Series F

The 5,000,000 First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.2250 per share per annum. On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at $26.00 per share if redeemed before December 1, 2012, at $25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013, at $25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014, at $25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015, and at $25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

First Preference Shares, Series G

The 9,200,000 First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends at a rate of $1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after that 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 per cent. 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.

Convertible Debentures

The Corporation’s US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due 2016, are redeemable by the Corporation 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 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. There is no provision associated with these debentures that restricts the payment of dividends.

Debt Covenant Restrictions on Dividend Distributions

The Trust Indenture pertaining to the Corporation's $100 million Senior Unsecured Debentures contains a covenant which provides that Fortis shall not declare or pay any dividends (other than stock dividends or cumulative preferred dividends on preferred shares not issued as stock dividends) or make any other distribution on its shares if, immediately thereafter, its consolidated funded obligations would be in excess of 75 per cent of its total consolidated capitalization.

The Corporation has a $600 million unsecured committed credit facility, maturing in May 2012, that can be used for general corporate purposes, including acquisitions. The credit facility contains a covenant which provides that Fortis shall not declare or pay any dividends or make any other restricted payments if, immediately thereafter, consolidated debt to consolidated capitalization ratio would exceed 70 per cent at any time.

8.0 CREDIT RATINGS

Securities issued by Fortis and its currently rated utilities are rated by one or more credit rating agencies, namely, DBRS, S&P and/or Moody's. The ratings assigned to securities issued by Fortis and its currently rated utilities are reviewed by the agencies on an ongoing basis. Credit ratings and stability ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are not recommendations to buy, sell or hold securities. Ratings may be subject to revision or withdrawal at any time by the rating organization. The following table summarizes the Corporation's credit ratings as at March 12, 2009.

Fortis
Credit Ratings

Company	DBRS	S&P	Moody's
Fortis	BBB (high), stable (unsecured debt)	A-, stable (unsecured debt)	N/A
Terasen	BBB (high), stable (unsecured debt)	BBB+, stable (1) (unsecured debt)	Baa 2, stable (unsecured debt)
TGI	A, stable (secured & unsecured debt)	A, stable (1) (unsecured debt)	A3, stable (unsecured debt)
TGVI	BBB (high), stable (unsecured debt)	N/A	A3, stable (unsecured debt)
FortisAlberta	A (low), stable (senior unsecured debt)	A-, stable (senior unsecured debt)	Baa 1, stable (senior unsecured debt)
FortisBC	BBB (high), stable (secured & unsecured debt)	N/A	Baa 2, stable (unsecured debt)
Newfoundland Power	A, stable (first mortgage bonds)	N/A	Baa 1, stable (first mortgage bonds)
Maritime Electric	N/A	A, stable (senior secured debt)	N/A
Caribbean Utilities	A (low), stable (senior unsecured debt)	A, stable (senior unsecured debt)	N/A

(1) Unsolicited

DBRS rates debt instruments by rating categories ranging from AAA to D, which represents the range from highest to lowest quality of such securities. DBRS states that: (a) its long-term debt ratings are meant to give an indication of the risk that the borrower will not fulfill its obligations in a timely manner with respect to both interest and principal commitments; (b) its ratings do not take factors such as pricing or market risk into consideration and are expected to be used by purchasers as one part of their investment decision; and (c) every rating is based on quantitative and qualitative considerations that are relevant for the borrowing entity. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of nine major categories. Such rating is assigned to debt instruments considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the BBB category are considered to have long-term debt of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The assignment of a (high) or (low) modified within each rating category indicates relative standing within such category.

S&P long-term debt ratings are on a ratings scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities. S&P uses '+' or '-' designations to indicate the relative standing of securities within a particular rating category. S&P states that its credit ratings are current opinions of the financial security characteristics with respect to the ability to pay under contracts in accordance with their terms. This opinion is not specific to any particular contract, nor does it address the suitability of a particular contract for a specific purpose or purchaser. An issuer rated A is regarded as having financial security characteristics to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than those in higher-rated categories.

Moody's long-term debt ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities. In addition, Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa to Caa to indicate relative standing within such classification. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the security ranks in the lower end of its generic rating category. Moody's states that its long-term debt ratings are opinions of relative risk of fixed-income obligations with an original maturity of one year or more and that such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. According to Moody's, a rating of Baa is the fourth highest of nine major categories and such a debt rating is assigned to debt instruments considered to be of medium-grade quality. Debt instruments rated Baa are subject to moderate credit risk and may possess certain speculative characteristics.

9.0 MARKET FOR SECURITIES

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 are listed on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.PR.G, respectively.

The following table sets forth the reported high and low trading prices and trading volumes for the Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G on a monthly basis for the year ended December 31, 2008.

Fortis
2008 Trading Prices and Volumes

	Common Shares			First Preference Shares, Series C		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	29.50	26.52	11,699,266	27.39	26.27	23,148
Feb	29.89	27.77	9,436,783	27.39	26.31	20,357
Mar	29.24	26.36	7,245,917	26.50	25.60	28,658
Apr	29.94	26.85	10,311,561	27.75	25.76	18,972
May	28.34	26.80	11,864,145	26.75	25.37	123,787
Jun	28.02	27.05	7,651,899	26.64	25.76	44,426
Jul	27.65	24.11	10,918,974	26.25	25.80	25,580
Aug	27.15	24.51	8,347,786	26.24	25.50	91,043
Sep	26.23	23.50	8,047,826	26.20	25.26	19,704
Oct	26.75	20.70	19,490,343	26.25	20.44	54,921
Nov	28.00	24.51	13,933,581	25.50	23.56	124,621
Dec	27.46	23.15	13,159,441	25.95	24.55	98,670
	First Preference Shares, Series E			**First Preference Shares, Series F**		
Month	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
Jan	26.62	25.98	115,209	22.50	21.33	206,795
Feb	26.96	26.49	10,705	23.50	22.00	111,470
Mar	26.89	25.50	43,889	23.20	21.25	103,475
Apr	26.50	25.51	33,454	22.88	21.09	116,137
May	25.97	25.00	330,602	22.40	21.40	86,078
Jun	26.70	24.80	52,730	21.87	19.00	166,441
Jul	26.50	24.50	31,794	20.00	18.00	159,824
Aug	26.49	24.55	39,848	20.35	19.75	100,320
Sep	26.39	24.85	89,850	20.50	18.50	113,705
Oct	24.50	23.00	44,208	18.99	16.57	224,945
Nov	24.99	22.50	28,650	19.78	16.00	100,535
Dec	25.99	21.00	108,907	17.85	15.50	241,520

	First Preference Shares, Series G [(1)]		
Month	**High ($)**	**Low ($)**	**Volume**
May	25.10	24.84	426,990
Jun	25.50	24.95	263,022
Jul	25.52	25.01	124,660
Aug	25.98	25.25	114,417
Sep	25.80	25.10	156,866
Oct	25.45	20.00	70,985
Nov	24.00	18.00	181,916
Dec	22.00	17.00	296,675

[(1)] The First Preference Share, Series G were issued in May and June 2008.

10.0 DIRECTORS AND OFFICERS

The Board adopted a director tenure policy in 1999 which is reviewed on a periodic basis and was most recently affirmed at a meeting of the Board held in September 2007. The tenure policy provides that Directors of the Corporation are to be elected for a term of one year and, except in exceptional circumstances determined by the Board, be eligible for re-election until the Annual Meeting of Shareholders next following the earlier of the date on which they achieve age 70 or the 10^{th} anniversary of their initial election to the Board. This policy became effective prospectively in 1999 and did not apply to Dr. Inkpen's service prior to 1999. The policy does not apply to Mr. Marshall whose service on the Board is related to his tenure as CEO. The following chart sets out the name and municipality of residence of each of the Directors of Fortis and indicates their principal occupations within five preceding years.

Fortis Directors	
Name	**Principal Occupations Within Five Preceding Years**
PETER E. CASE (1) Freelton, Ontario	Mr. Case, 54, a Corporate Director, retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. During his 17-year career as senior investment analyst with CIBC World Markets and BMO Nesbitt Burns and its predecessors, Mr. Case's coverage of Canadian and selected US pipeline and energy utilities was consistently rated among the top rankings. He was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto. Mr. Case was first elected to the Board in May 2005. Mr. Case was appointed to the Board of Directors of FortisOntario Inc. in March 2003 and assumed the Chair of the FortisOntario Inc. Audit Committee in January 2004. Mr. Case does not serve as a director of any other reporting issuer.
FRANK J. CROTHERS Nassau, Bahamas	Mr. Crothers, 64, is Chairman and Chief Executive Officer of Island Corporate Holdings Limited, Nassau, Bahamas. Over the past 35 years, he has served on many public and private sector boards. For over a decade he was on the Board of Harvard University Graduate School of Education and also 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 the Corporation on August 28, 2006. Mr. Crothers is the Vice Chair of the Board of Caribbean Utilities and serves on the Board of Belize Electricity Limited. Mr. Crothers was first elected to the Fortis Board in May 2007. He is also a director of reporting issuers Franklin Templeton Resources, Fidelity Merchant Bank & Trust (Cayman) Limited, Talon Metals Corp. and Victory Nickel Inc.
GEOFFREY F. HYLAND (1)(2)(3) Caledon, Ontario	Mr. Hyland, 64, a Corporate Director, retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. He graduated from McGill University with a Bachelor of Engineering (Chemical) and York University with a Master of Business Administration. Mr. Hyland was first elected to the Board in May 2001 and was appointed Chair of the Board in May 2008. 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.
LINDA L. INKPEN (2)(4) St. Philips, Newfoundland and Labrador	Dr. Inkpen, 61, retired from her medical practice in December 2008 after 35 years of service. She has served as a Commissioner of the Royal Commission on Employment and Unemployment, Province of Newfoundland and Labrador and is past President of the College of the North Atlantic. She is past Chair of the Medical Advisory Committee for the St. John's hospitals for Eastern Health, Newfoundland and Labrador. Dr. Inkpen was named a member of the Order of Canada in 1998 and awarded the Queen's Jubilee Medal. She graduated from Memorial University of Newfoundland with a Bachelor of Science, a Bachelor of Education, a Bachelor of Medical Science and a Doctor of Medicine. Dr. Inkpen was first elected to the Board in April 1994. Dr. Inkpen is past Chair of the Boards of Fortis Properties Corporation and Newfoundland Power. She does not serve as a director of any other reporting issuer. Dr. Inkpen will be retiring from the Fortis Board at the Annual Meeting on May 5, 2009.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
H. STANLEY MARSHALL Paradise, Newfoundland and Labrador	Mr. Marshall, 58, is President and Chief Executive Officer of the Corporation. He joined Newfoundland Power in 1979 and was appointed President and Chief Executive Officer of Fortis in 1996. Mr. Marshall graduated from the University of Waterloo with a Bachelor of Applied Science (Chem. Eng.) and Dalhousie University with a Bachelor of Laws. He is a member of the Law Society of Newfoundland and Labrador and a Registered Professional Engineer in the Province of Newfoundland and Labrador. Mr. Marshall was first elected to the Board in October 1995. Mr. Marshall serves on the boards of all Fortis utilities in western Canada and the Caribbean (including Caribbean Utilities) and the Board of Fortis Properties Corporation. He is also a director of Toromont Industries Ltd.
JOHN S. McCALLUM (1)(2) Winnipeg, Manitoba	Mr. McCallum, 65, has been a Professor of Finance at the University of Manitoba since July 1973. He served as Chairman of Manitoba Hydro from 1991 to 2000 and as Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto. Mr. McCallum was first elected to the Board in July 2001 and was appointed Chair of the Governance and Nominating Committee of the Corporation in May 2005. He is a director of FortisBC Inc. and FortisAlberta Inc. and chairs the Audit, Risk and Environment Committees of both companies. He also serves as a director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.
HARRY McWATTERS (2) Summerland, British Columbia	Mr. McWatters, 63, is the founder and past President of Sumac Ridge Estate Wine Group, a leader in the British Columbia Wine industry. He is President of Vintage Consulting Group Inc. and Harry McWatters Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd., all of which are engaged in various aspects of the British Columbia wine industry. Mr. McWatters was first elected to the Board in May 2007. He was elected to the Board of FortisBC Inc. in September 2005 and appointed as Chair of that company's Board in 2006. Mr. McWatters became a director of Terasen Inc. in November 2007 and does not serve as a director of any other reporting issuer.
DAVID G. NORRIS (1)(3) St. John's, Newfoundland and Labrador	Mr. Norris, 61, a Corporate Director, has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with the Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. Mr. Norris was first elected to the Board in May 2005 and, in May 2006, he was appointed Chair of the Audit Committee of the Board. He has been a director of Newfoundland Power since 2003 and was appointed Chair of that company's Board in April 2006. Mr. Norris was appointed to the Board of Fortis Properties Corporation in 2006. He does not serve as a director of any other reporting issuer.
MICHAEL A. PAVEY (3) Moncton, New Brunswick	Mr. Pavey, 61, a Corporate Director, retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in September 2006. Prior to joining Major Drilling Group International Inc. in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey graduated from the University of Waterloo with a Bachelor of Applied Science (Mechanical Engineering) and from McGill University with a Master of Business Administration. He retired from the Board of Maritime Electric in February 2007 after a six-year term, which included three years' service as Chair of that company's Audit and Environment Committee. Mr. Pavey was first elected to the Board in May 2004. Mr. Pavey does not serve as a director of any other reporting issuer.

Fortis Directors *(continued)*	
Name	**Principal Occupations Within Five Preceding Years**
ROY P. RIDEOUT (2)(3) Halifax, Nova Scotia	Mr. Rideout, 61, a Corporate Director, retired as Chairman and Chief Executive Officer of Clarke Inc. in October 2002. Prior to 1998, he served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. Mr. Rideout graduated with a Bachelor of Commerce from Memorial University of Newfoundland and obtained designation as a Chartered Accountant. Mr. Rideout was first elected to the Board in March 2001. He is the Chair of the Human Resources Committee of the Board and has held that position since May 2003. Mr. Rideout serves as a director of the Halifax International Airport Authority and NAV CANADA.

(1) Serves on the Audit Committee
(2) Serves on the Governance and Nominating Committee
(3) Serves on the Human Resources Committee
(4) Dr. Inkpen will not be standing for re-election as director at the Annual Meeting of Shareholders on May 5, 2009, in accordance with Board policy.

The following table sets out the name and municipality of residence of each of the officers of Fortis and indicates the office held.

Fortis Officers	
Name and Municipality of Residence	**Office Held**
H. Stanley Marshall Paradise, Newfoundland and Labrador	President and Chief Executive Officer (1)
Barry V. Perry Mount Pearl, Newfoundland and Labrador	Vice President, Finance and Chief Financial Officer (2)
Ronald W. McCabe St. John's, Newfoundland and Labrador	Vice President, General Counsel and Corporate Secretary (3)
Donna G. Hynes St. John's, Newfoundland and Labrador	Assistant Secretary (4)

(1) Mr. Marshall was appointed President and Chief Operating Officer, effective October 1, 1995. Effective May 1, 1996, Mr. Marshall became Chief Executive Officer.
(2) Mr. Perry was appointed Vice President, Finance and Chief Financial Officer, effective January 1, 2004. Prior to that time, Mr. Perry was Vice President, Finance and Chief Financial Officer of Newfoundland Power.
(3) Mr. McCabe was appointed General Counsel and Corporate Secretary, effective January 1, 1997. Effective May 6, 2008, Mr. McCabe became Vice President, General Counsel and Corporate Secretary.
(4) Ms. Hynes was appointed Assistant Secretary, effective December 8, 1999. She joined Fortis as Manager, Investor and Public Relations in October 1999 and, prior to that time, was employed by Newfoundland Power.

As at December 31, 2008, the directors and officers of Fortis, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 682,714 Common Shares, representing 0.4 per cent of the issued and outstanding Common Shares of Fortis. The Common Shares are the only voting securities of the Corporation.

11.0 AUDIT COMMITTEE

11.1 Education and Experience

The education and experience of each Audit Committee Member that is relevant to such Member's responsibilities as a Member of the Audit Committee are set out below. As at December 31, 2008, the Audit Committee was composed of the following persons.

Fortis Audit Committee	
Name	**Relevant Education and Experience**
PETER E. CASE Freelton, Ontario	Mr. Case retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Mr. Case was awarded a Bachelor of Arts and a Master of Business Administration from Queen's University and a Master of Divinity from Wycliffe College, University of Toronto.
GEOFFREY F. HYLAND Caledon, Ontario	Mr. Hyland retired as President and Chief Executive Officer of ShawCor Ltd. in June 2005 after 37 years of service. Mr. Hyland graduated from McGill University with a Bachelor of Engineering (Chemical) and from York University with a Master of Business Administration.
JOHN S. McCALLUM Winnipeg, Manitoba	Mr. McCallum is a Professor of Finance at the University of Manitoba. Mr. McCallum graduated from the University of Montreal with a Bachelor of Arts (Economics) and a Bachelor of Science (Mathematics). He was awarded a Master of Business Administration from Queen's University and a PhD in Finance from the University of Toronto.
DAVID G. NORRIS *(Chair)* St. John's, Newfoundland and Labrador	Mr. Norris graduated with a Bachelor of Commerce from Memorial University of Newfoundland and a Master of Business Administration from McMaster University. Mr. Norris 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.

The Board has determined that each of the Audit Committee Members is independent and financially literate. Independent means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110 - Audit Committees. Financially literate means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

11.2 Audit Committee Mandate

The text of the Corporation's Audit Committee Mandate is detailed below.

Objective

The Audit Committee shall provide assistance to the Board by overseeing the external audit of the Corporation's annual financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation.

Definitions

In this mandate:

"AIF" means the Annual Information Form filed by the Corporation;

"Committee" means the Audit Committee appointed by the Board pursuant to this mandate;

"Board" means the board of directors of the Corporation;

"CICA" means the Canadian Institute of Chartered Accountants or any successor body;

"Corporation" means Fortis Inc.;

"**Director"** means a member of the Board;

"Financially Literate" means having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breath and complexity of the issues that can reasonably be expected to be present in the Corporation's financial statements;

"External Auditor" means the firm of chartered accountants, registered with the Canadian Public Accountability Board or its successor, and appointed by the shareholders of the Corporation to act as External Auditor of the Corporation;

"Independent" means free from any direct or indirect material relationship with the Corporation which, in the view of the Board, could reasonably be expected to interfere with the exercise of a Member's independent judgment as more particularly described in Multilateral Instrument 52-110;

"Internal Auditor" means the person employed or engaged by the Corporation to perform the internal audit function of the Corporation;

"Management" means the senior officers of the Corporation;

"MD&A" means the Corporation's management discussion and analysis prepared in accordance with National Instrument 51-102F1 in respect of the Corporation's annual and interim financial statements; and

"Member" means a Director appointed to the Committee.

Composition and Meetings

1. The Committee shall be appointed annually by the Board and shall be comprised of three (3) or more Directors; each of whom is Independent and Financially Literate and none of whom is a member of Management or an employee of the Corporation or of any affiliate of the Corporation.

2. The Board shall appoint a Chair of the Committee on the recommendation of the Corporation's Governance and Nominating Committee, or such other committee as the Board may authorize.

3. The Committee shall meet at least four (4) times each year and shall meet at such other times during the year as it deems appropriate. Meetings of the Committee shall be held at the call of: (i) the Chair of the Committee, or (ii) any two (2) Members, or (iii) the External Auditor.

4. The President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, the External Auditor and the Internal Auditor shall receive notice of, and (unless otherwise determined by the Chair of the Committee) shall attend all meetings of the Committee.

5. A quorum at any meeting of the Committee shall be three (3) Members.

6. The Chair of the Committee shall act as chair of all meetings of the Committee at which the Chair is present. In the absence of the Chair from any meeting of the Committee, the Members present at the meeting shall appoint one of their Members to act as Chair of the meeting.

7. Unless otherwise determined by the Chair of the Committee, the Secretary of the Corporation shall act as secretary of all meetings of the Committee.

Oversight of the External Audit and the Accounting and Financial Reporting and Disclosure Processes and Policies

The primary purpose of the Committee is oversight of the Corporation's external audit and the accounting and financial reporting and disclosure processes and policies on behalf of the Board. Management of the Corporation is responsible for maintaining appropriate accounting and financial reporting principles, policies, internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Management is responsible for the preparation and integrity of the financial statements of the Corporation.

1. Oversight of the External Audit

   The oversight of the external audit pertains to the audit of the Corporation's annual financial statements.

   1.1. The Committee is responsible for the evaluation and recommendation of the External Auditor to be proposed by the Board for appointment by the shareholders.

   1.2. In advance of each audit, the Committee shall review the External Auditor's audit plan including the general approach, scope and areas subject to risk of material misstatement.

   1.3. The Committee is responsible for approving the terms of engagement and fees of the External Auditor.

   1.4. The Committee shall review and discuss the Corporation's annual audited financial statements, together with the External Auditor's report thereon, and MD&A with Management and the External Auditor to gain reasonable assurance as to the accuracy, consistency and completeness thereof. The Committee shall meet privately with the External

Auditor. The Committee shall oversee the work of the External Auditor and resolve any disagreements between Management and the External Auditor.

1.5. The Committee shall use reasonable efforts, including discussion with the External Auditor, to satisfy itself as to the External Auditor's independence as defined in the CICA Assurance Handbook Section 5751.

2. Oversight of the Accounting and Financial Reporting and Disclosure Processes

2.1. The Committee shall recommend the annual audited financial statements together with the MD&A for approval by the Board.

2.2. The Committee shall review the interim unaudited financial statements with the External Auditor and Management, together with the External Auditor's review engagement report thereon.

2.3. The Committee shall review and approve publication of the interim unaudited financial statements, together with the interim MD&A and earnings media release on behalf of the Board.

2.4. The Committee shall review and recommend approval by the Board of the Corporation's AIF, Management Information Circular, any prospectus and other financial information or disclosure documents to be issued by the Corporation prior to their public release.

2.5. The Committee shall use reasonable efforts to satisfy itself as to the integrity of the Corporation's financial information systems, internal control over financial reporting and the competence of the Corporation's accounting personnel and senior financial management responsible for accounting and financial reporting.

2.6. The Committee shall be responsible for the oversight of the Internal Auditor.

3. Oversight of the Audit Committee Mandate and Policies

On a periodic basis, the Committee shall review and report to the Board on the Audit Committee Mandate as well as on the following policies:

3.1. Reporting Allegations of Suspected Improper Conduct and Wrongdoing Policy;

3.2. Derivative Financial Instruments and Hedging Policy;

3.3. Pre-Approval of Audit and Non-Audit Services Policy;

3.4. Hiring of Employees from Independent Auditing Firms Policy;

3.5. The Internal Audit Role and Function Policy; and

3.6. any other policies that may be established, from time to time, relating to accounting and financial reporting and disclosure processes; oversight of the external audit of the Corporation's financial statement; and oversight of the internal audit function.

Reporting

The Chair of the Committee, or another designated Member, shall report to the Board at each regular meeting on those matters which were dealt with by the Committee since the last regular meeting of the Board.

Other

1. The Committee shall perform such other functions as may, from time to time, be assigned to the Committee by the Board.

2. The Committee may approve, in circumstances that it considers appropriate, the engagement by the Committee or any Director of outside advisors or persons having special expertise at the expense of the Corporation.

11.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy which requires pre-approval of all audit and non-audit services provided to the Corporation and its subsidiaries by the Corporation's External Auditor. The Pre-Approval of Audit and Non-Audit Services Policy describes the services which may be contracted from the External Auditor and the limitations and authorization procedures related thereto. This policy defines services such as bookkeeping, valuations, internal audit and management functions which may not be contracted from the External Auditor and establishes an annual limit for permissible non-audit services not greater than the total fee for audit services. Audit Committee pre-approval is required for all audit and non-audit services.

11.4 External Auditor Service Fees

The fees paid by the Corporation to Ernst & Young LLP, the Corporation's External Auditors, during each of the last two fiscal years for audit, audit-related, tax and non-audit services were as follows:

Fortis External Auditor Service Fees ***($ thousands)***		
Ernst & Young LLP	**2008**	2007
Audit Fees	**$ 2,467.3**	$ 1,822.1
Audit-Related Fees	**853.0**	603.7
Tax Fees	**125.8**	181.9
Total	**$ 3,446.1**	$ 2,607.7

The increase in audit fees in 2008, as compared to 2007, primarily related to Caribbean Utilities associated with its change in auditors to Ernst & Young LLP for the fiscal year ended April 30, 2008, the requirement for an additional year-end audit associated with the change in the utility's year end to December 31, 2008 and increased audit work arising from the full year of Terasen inclusion as a subsidiary.

12.0 TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and First Preference Shares of Fortis is Computershare Trust Company of Canada in Halifax, Montréal and Toronto.

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com/fortisinc

13.0 AUDITORS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, The Fortis Building, 7th Floor, 139 Water Street, St. John's, NL, A1C 1B2. The financial statements of the Corporation for the fiscal year ended December 31, 2008 have been audited by Ernst & Young LLP. Ernst & Young LLP report that they are independent of the Corporation in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Newfoundland.

14.0 ADDITIONAL INFORMATION

Reference is made to the MD&A on pages 20 through 79 of the 2008 Fortis Inc. Annual Report to Shareholders, which pages are incorporated herein by reference. Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Further additional information, including officers' and directors' remuneration and indebtedness, principal holders of the securities of Fortis, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Management Information Circular of Fortis dated April 3, 2009 for the May 5, 2009 Annual Meeting of Shareholders. Additional financial information is also provided in the comparative consolidated financial statements and MD&A of Fortis for the year ended December 31, 2008.

Requests for additional copies of the above-mentioned documents, as well as the 2008 Annual Information Form, should be directed to the Corporate Secretary, Fortis, P.O. Box 8837, St. John's, NL, A1B 3T2 (telephone: 709.737.2800). In addition, such documentation and additional information relating to the Corporation is contained on the Corporation's website at www.fortisinc.com.