Q. Please provide a copy of the Annual reports of Fortis Inc. from 2006 to current.

A. Copies of the Fortis Inc. Annual Reports for the years 2006, 2007 and 2008 inclusive are attached as Attachments A, B and C, respectively.

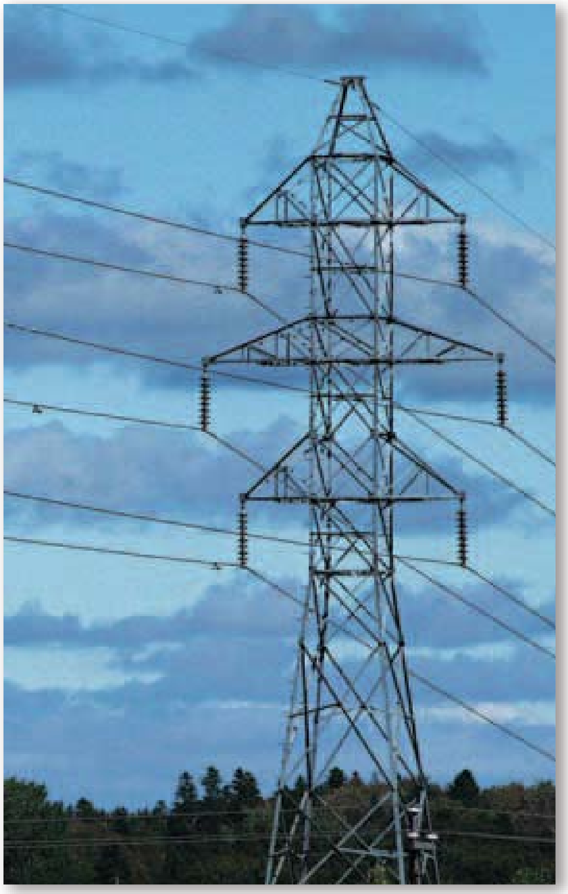
Fortis Inc.
2006 Annual Report

FORTIS INC.

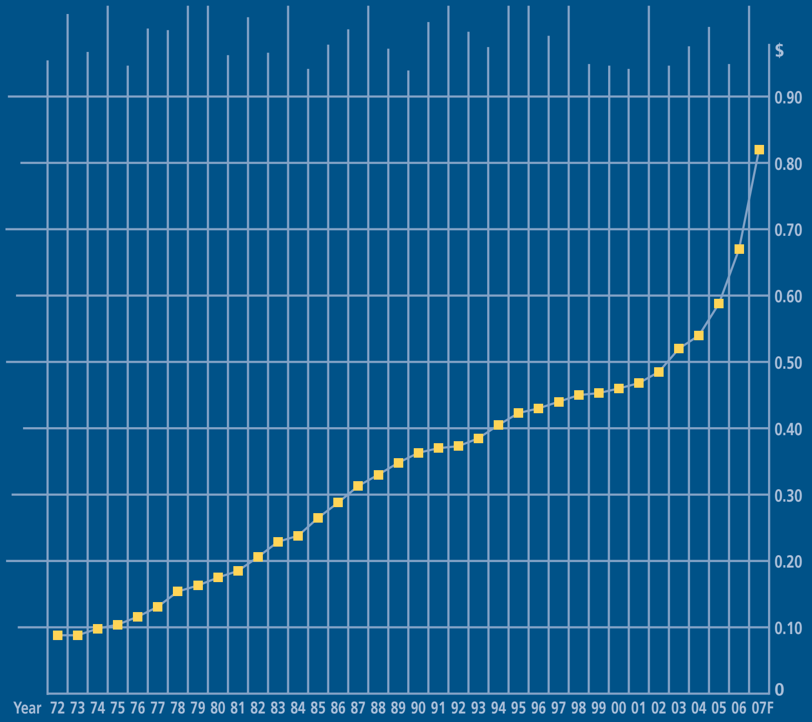
2006 ANNUAL REPORT

powering **performance**

TABLE OF CONTENTS



Dividends paid per common share



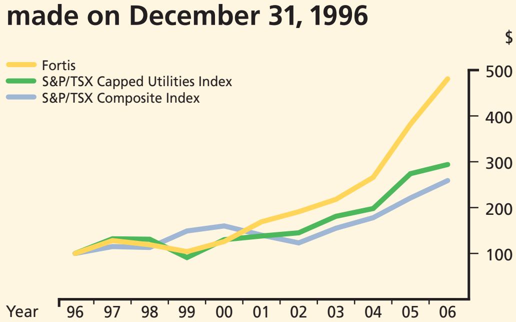
Fortis has increased its annual dividend paid to common shareholders for 34 consecutive years, the longest record of any public corporation in Canada.

Annual Comparison *($ millions except per share amounts)*

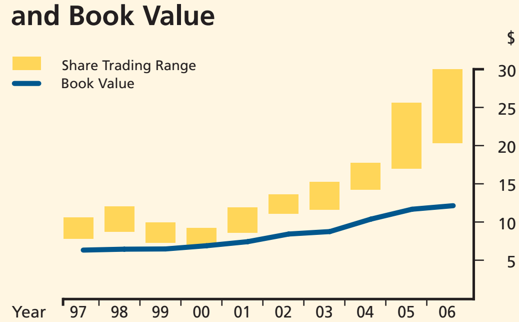
	2006	2005
Revenue and equity income	**1,472**	1,441
Net earnings applicable to common shares	**147**	137
Total assets	**5,447**	4,597
Total shareholders' equity	**1,398**	1,213
Cash flow from operations	**263**	304
Earnings per common share	**1.42**	1.35
Dividends paid per common share	**0.67**	0.59

Fortis Inc.

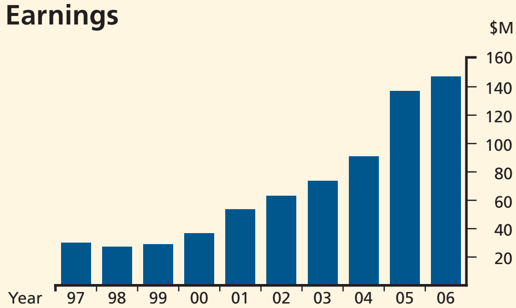
Value of an Investment of $100 made on December 31, 1996



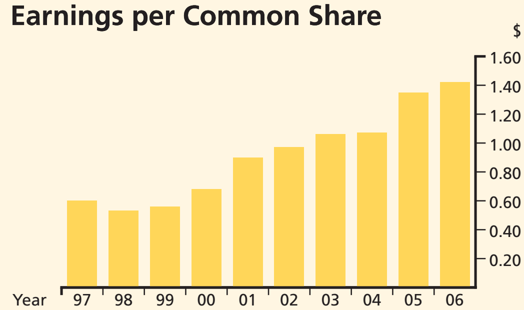
Share Trading Range and Book Value



Earnings



Earnings per Common Share



Unless otherwise specified, all dollar amounts in this Annual Report are expressed in Canadian dollars.

Fortis Inc. ("Fortis" or the "Corporation") is principally a diversified, international distribution utility holding company with assets exceeding $5.4 billion and annual revenues of approximately $1.5 billion.

Fortis has holdings in eight regulated electric distribution utilities. **FortisAlberta** owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. **FortisBC** is a vertically integrated utility which generates, transmits and distributes electricity in the southern interior of British Columbia. **Newfoundland Power** is the principal distributor of electricity in Newfoundland. **Maritime Electric** is the principal distributor of electricity on Prince Edward Island. **FortisOntario** distributes electricity in the Fort Erie, Port Colborne, Cornwall and Gananoque areas of Ontario. **Belize Electricity** is the distributor of electricity in Belize, Central America. **Caribbean Utilities** is the sole provider of electricity on Grand Cayman, Cayman Islands. **Fortis Turks and Caicos** is the principal distributor of electricity in the Turks and Caicos Islands.

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these assets is 195 megawatts ("MW"), 190 MW of which is hydroelectric.

Fortis Properties owns and operates 18 hotels in seven Canadian provinces and 2.7 million square feet of commercial real estate in Atlantic Canada.

The Fortis Group of Companies has approximately 4,400 employees. Fortis utilities serve more than 1,000,000 customers and met a combined peak demand of approximately 5,100 MW in 2006.

On February 26, 2007, Fortis entered into an agreement with Kinder Morgan, Inc. to buy Terasen Gas, one of the largest natural gas distribution utilities in Canada. Terasen Gas is the principal natural gas distribution utility in British Columbia, serving approximately 900,000 customers or 95 per cent of natural gas users in the province. Its service territory includes the populous lower mainland, Vancouver Island and the southern interior of the province. The acquisition is expected to close in mid-2007.

FORTIS INC.

Regulated Utility Operations ■

FortisAlberta
Alberta

FortisBC
British Columbia

Newfoundland Power
Newfoundland

Maritime Electric
Prince Edward Island

FortisOntario
Ontario

Belize Electricity
Belize

Caribbean Utilities
Grand Cayman

Fortis Turks and Caicos
Turks and Caicos Islands

Non-Regulated Operations

Generation ●
Production Areas
- *Belize*
- *Ontario*
- *Central Newfoundland*
- *British Columbia*
- *Upper New York State*

Fortis Properties ▲
Real Estate
- *Atlantic Canada*

Hotels
- *Eastern Canada*
- *Manitoba*
- *Alberta*
- *British Columbia*

REPORT TO SHAREHOLDERS

For the seventh consecutive year, Fortis has delivered record earnings to shareholders. Earnings applicable to common shares were $147.2 million, 7.4 per cent higher than earnings of $137.1 million last year. Earnings in 2005 included a $7.9 million after-tax gain resulting from the settlement of contractual matters between FortisOntario and Ontario Power Generation Inc. Earnings per common share were $1.42 compared to $1.35 last year.

Dividends paid to common shareholders in 2006 increased to 67 cents per common share from 59 cents per common share last year. Commencing with the second quarter dividend payable on June 1, 2007, Fortis increased its quarterly common share dividend 10.5 per cent to 21 cents from 19 cents. Our history of profitable growth has enabled Fortis to increase its annual dividend paid for 34 consecutive years, the longest record of any public corporation in Canada. The dividend payout ratio remained stable at 47.2 per cent in 2006.

Fortis delivered a total return to shareholders of 26 per cent in 2006, outperforming the S&P/TSX Composite Index and S&P/TSX Utilities Index, which delivered total returns of 17.3 per cent and 6.8 per cent, respectively. Over the past five years,

H. Stanley Marshall, President and CEO, Fortis Inc. (left) and Bruce Chafe, Chair of the Board, Fortis Inc. (right)

Fortis owns non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

Fortis has delivered an average annualized total return of 24.5 per cent, again exceeding the S&P/TSX Utilities Index and S&P/TSX Composite Index performance of 15.6 per cent and 13.1 per cent, respectively, over the same period.

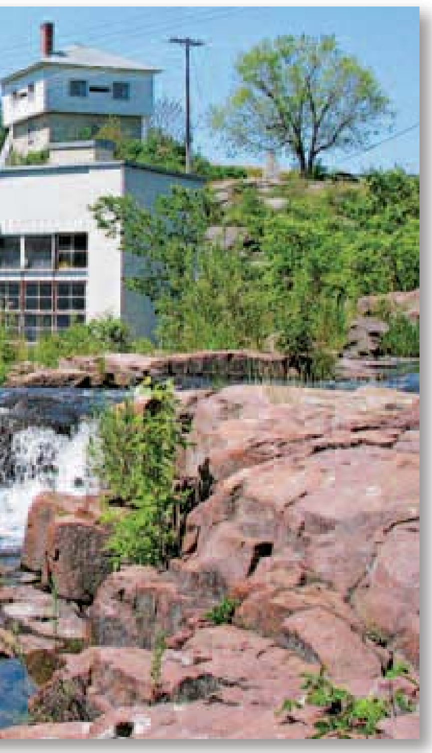
Our common share market capitalization increased to approximately $3.1 billion from $2.5 billion last year. Fortis common shares reached an all-time high of $30.00 on December 27, 2006 and closed for the year at $29.77. Our average daily trading volume approached 240,000 common shares, almost 60 per cent higher than in 2005.

Fortis has grown rapidly in Canada and the Caribbean over the past decade. Total assets exceeding $5.4 billion at year end are more than five times asset size a decade ago. Our asset growth has been driven by profitable acquisitions, including the $1.5 billion purchase of our two utilities in Western Canada in May 2004. Asset growth also arises organically from the continued investment in the distribution systems of our utilities. The rate bases of FortisAlberta and FortisBC have increased approximately 29 per cent and 36 per cent, respectively, since the utilities were acquired. Over the next two years, each utility's rate base is expected to grow approximately 30 per cent.

The diversification of our operations significantly reduces the impact of changes in regional economies, weather and regulation. Regulated electric utilities, which have been our main business, comprise approximately 86 per cent of the total assets of Fortis. Regulated electric utility assets in Canada comprise 71 per cent of total assets. The regulated rate base of Fortis utilities exceeds $3.0 billion.

Fortis owns and/or operates more than 131,000 kilometres of transmission and distribution lines. Consolidated energy sales and deliveries totalled approximately 27,000 gigawatt hours ("GWh") and our utilities met a combined peak demand of approximately 5,100 MW in 2006. Our regulated utilities serve more than 1,000,000 customers in five Canadian provinces and three Caribbean countries.

We achieved a new milestone this year when we expanded our business to a third Caribbean country, the Turks and Caicos Islands. In August, Fortis acquired two electric utilities in the Turks and Caicos Islands, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd., (collectively referred to as "Fortis Turks and Caicos"), for aggregate consideration of



Our asset growth has been driven by profitable acquisitions, including the $1.5 billion purchase of FortisAlberta and FortisBC in May 2004.

approximately US$90 million. This acquisition was immediately accretive to earnings. Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity users, in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037. The Turks and Caicos Islands is experiencing rapid growth in energy demand, driven by a strong developing economy. With well-established distribution utilities in Belize and Grand Cayman, Fortis has considerable experience meeting the energy needs of growing communities in the Caribbean region. Our customers in the Turks and Caicos Islands will benefit from the expertise of Fortis in delivering reliable service.

In November, Fortis increased its investment in Caribbean Utilities to approximately 54 per cent to become controlling shareholder. This investment, which was also immediately accretive to earnings, reflects our confidence in the future of Grand Cayman and the ability of Caribbean Utilities to meet the existing and future energy needs of its customers.

Fortis is the leading operator of electric distribution utilities in Canada. Our increased investment in Caribbean Utilities, combined with our investments in Belize Electricity and Fortis Turks and Caicos, positions Fortis as a leading utility operator in the Caribbean region.

Significant capital investments in utility infrastructure and growth from acquisitions were the major drivers of performance this year.

Canadian Regulated Utilities contributed $112.7 million to earnings this year, 7.5 per cent higher than earnings of $104.8 million last year. Underpinning the results of our Canadian Regulated Utilities was the performance of FortisAlberta and FortisBC which contributed $41.4 million and $27.4 million, respectively, to earnings. Our western utilities, especially FortisAlberta, continue to maintain, enhance and expand their distribution systems at an unprecedented pace to accommodate new customers and improve system reliability. Lower corporate income taxes and a 5.9 per cent increase in electricity rates at FortisBC also favourably impacted earnings at our western utilities.

Newfoundland Power's earnings of $30.1 million were slightly lower than last year, mainly due to a decline in energy sales, lower interest revenue and higher costs.

Maritime Electric delivered earnings of $9.8 million this year. Growth in earnings was largely driven by the impact of the 3.35 per cent increase in basic electricity rates, effective July 1, 2006.

Our regulated utilities serve more than 1,000,000 customers in five Canadian provinces and three Caribbean countries.

Fortis owns and/or operates more than 131,000 kilometres of transmission and distribution lines.

In early 2006, Maritime Electric commissioned its new $35 million 50-MW combustion turbine generator, which will address issues associated with the loading of the submarine cables to Prince Edward Island and provide increased reliability and security of energy supply. In August, the Company received regulatory approval of its application for a 39-MW Wind Power Purchase Agreement (the "Agreement") with PEI Energy Corporation. Recent legislation by the Government of Prince Edward Island will require Maritime Electric to obtain at least 15 per cent of its annual energy requirements from renewable sources, such as wind-powered energy, by 2010. The Agreement, in conjunction with the existing wind-energy purchase agreements, enables the Company to reach this target.

At FortisOntario, excluding the $1.6 million adjustment recorded in 2005 related to taxes, earnings of $4.0 million were higher year over year primarily as a result of increases in distribution rates, effective May 1, 2006.

All five of our Canadian Regulated Utilities were involved in significant rate proceedings in 2006. In the first half of 2006, FortisAlberta and FortisBC each reached Negotiated Settlement Agreements with their customers and stakeholders, which were approved by the utilities' respective regulators, thereby eliminating the need for full-scale hearings. At FortisBC, a new multi-year performance-based rate-setting mechanism was also approved. The allowed rate of return on common equity ("ROE") for each of our three largest utilities, FortisAlberta, FortisBC and Newfoundland Power, is formula based and tied to long-term Canada bond yields. The 2006 allowed ROEs for FortisAlberta and FortisBC were set at 8.93 per cent and 9.2 per cent, respectively. Given the lower bond yields, the 2007 allowed ROEs for FortisAlberta and FortisBC have declined to 8.51 per cent and 8.77 per cent, respectively.

In January 2006, Newfoundland Power received regulatory approval of its final 2006 electricity rates, which remained unchanged from 2005. The allowed ROE for the purpose of setting rates was 9.24 per cent. The Company's 2007 allowed ROE has declined to 8.6 per cent, reflecting lower bond yields.

Our Caribbean Regulated Utilities contributed $23.6 million to earnings this year, $4.2 million higher than earnings in 2005. Earnings growth was largely driven by four months of contributions from Fortis Turks and Caicos and improved earnings at Belize Electricity, primarily due to lower finance charges, growth in energy sales and an overall 11 per cent increase in electricity rates, effective July 1, 2005.

Fortis increased its ownership in Caribbean Utilities to approximately 54 per cent in 2006. Caribbean Utilities serves more than 22,000 customers including the Ritz-Carlton on world-famous Seven Mile Beach in Grand Cayman, Cayman Islands.

Belize Electricity received regulatory approval of an overall 13 per cent increase in electricity rates, effective January 1, 2006. The increase reflected rising fuel costs, which flow through in customer rates and, therefore, had no impact on the Company's earnings. In May, the utility's regulator issued its final decision regarding Belize Electricity's Annual Tariff Review Application. Electricity rates remain unchanged for the period July 1, 2006 through June 30, 2007 from those in effect at January 1, 2006. Belize Electricity is allowed to earn a rate of return on assets of 15 per cent.

Peak energy demand in Belize rose to 67 MW this year, 1.6 times the level of demand when Fortis invested in Belize Electricity in 1999. The Company benefited from lower-cost energy generated by the hydroelectric plants of Belize Electric Company Limited ("BECOL") this year. Belize Electricity continues to pursue opportunities to strengthen its energy supply sources to meet growing energy demand in the country.

Fortis began consolidating its 54 per cent interest in Caribbean Utilities upon acquiring control of the utility in November. Prior to acquiring controlling interest, Fortis accounted for its investment in the Company on an equity basis.

Equity income from Caribbean Utilities was $1.7 million lower than last year. Excluding the $1.1 million positive adjustment to equity income in 2005 related to a change in the Company's accounting practice for recognizing unbilled revenue, equity income decreased $0.6 million due to the impact of foreign currency translation.

Licence negotiations between Caribbean Utilities and the Government of the Cayman Islands recommenced in November 2005 and are ongoing. The Company's Licence remains in full force and effect until January 2011 or until it is replaced with a new licence by mutual agreement.

In June, the number of customers at Caribbean Utilities surpassed pre-Hurricane Ivan levels. At the end of July, the Company's total owned generating capacity reached 120 MW compared to 123 MW before Hurricane Ivan.

Fortis invested approximately $500 million in its consolidated capital program in 2006. The majority of this investment was driven by robust customer growth in Western Canada and the continuing need to maintain and enhance the reliability of distribution systems. FortisAlberta's gross investment in capital projects was approximately $243 million this year, an increase of 47 per cent over 2005. New customer connections accounted for almost half of the Company's capital projects this year. FortisAlberta also invested $73 million related to capital upgrades and replacements, and to increase the capacity of its distribution network. FortisBC's gross investment in capital projects was approximately $111 million this year.

We remain focused on operating efficient utilities while meeting the growing energy needs of our customers.

Fortis invested approximately $500 million in its consolidated capital program in 2006.

Among the initiatives undertaken, work valued at $60 million commenced on three new large substations and associated transmission lines to meet growing demand in the Okanagan and Boundary areas. FortisBC also invested approximately $11 million as part of its generation asset upgrade life-extension program. Newfoundland Power invested approximately $60 million in its capital projects, primarily to upgrade distribution feeders to enhance reliability performance.

Annual energy sales from Non-regulated Fortis Generation operations exceeded 1,200 GWh this year. Approximately 60 per cent of energy sales were into the Ontario marketplace. The generating capacity of the Non-regulated Fortis Generation business is 195 MW, 190 MW of which is hydroelectric.

Non-regulated Fortis Generation contributed earnings of $26.7 million this year compared to $29.6 million last year. Excluding the $7.9 million after-tax gain recorded last year, earnings were $5.0 million higher year over year. Improved performance in Belize, driven by increased hydroelectric production and lower finance charges, was partially offset by the impact of lower average wholesale energy prices in Ontario. The average annual wholesale energy price per megawatt hour in Ontario was $46.38 in 2006 compared to $68.49 last year.

Our hydroelectric production in Belize climbed to 178 GWh this year, more than two-and-a-half times the level of production in 2005. The increased production was primarily due to the first full year of operations of the Chalillo storage facility which, at full supply level, contains the equivalent of approximately 45 GWh of hydroelectric production. Hydroelectricity, the least cost and most environmentally responsible energy source, now accounts for approximately 43 per cent of the energy supply of Belize. Fortis will continue to work with the Government of Belize to identify potential energy developments that will help address the growing energy demands of Belize and maintain stable electricity rates for customers.

This year marked the ninth consecutive year of record earnings for Fortis Properties. The Company delivered earnings of $18.7 million, 32.6 per cent higher than earnings in 2005. The growth in earnings was largely driven by a $1.6 million after-tax gain on the sale of the Days Inn Sydney hotel, reduced corporate income taxes and growth at hotel operations in Western Canada.

Fortis Properties completed an acquisition of four hotels in Alberta and British Columbia in November for approximately $52 million. This acquisition strengthens the Company's presence in Western Canada, an area of strong economic activity. It enables Fortis Properties to continue to grow its earnings while building on its reputation for superior customer service at high-quality, well-positioned, mid-market hotels. The addition of these hotels increases the Company's portfolio to 18 hotels in seven Canadian provinces, operating more than 3,200 rooms.

Fortis Properties completed the acquisition of four hotels in Alberta and British Columbia in 2006 for approximately $52 million.

Investors have demonstrated confidence in our strategy of profitable growth. In September, Fortis raised $125 million through the issuance of 5 million perpetual Preferred Shares that carry a dividend rate of 4.9 per cent. The net proceeds of the issue were used principally to support the acquisition of Fortis Turks and Caicos and to fund equity injections into FortisAlberta and FortisBC in support of the utilities' extensive capital expenditure programs. In January 2007, Fortis issued 5.17 million common shares at $29.00 per common share, resulting in gross proceeds of approximately $150 million. The net proceeds of the issue were used to repay indebtedness incurred for acquisitions, to support the capital expenditure programs of our western utilities and for general corporate purposes.

The corporate credit ratings of the unsecured debt of Fortis are stable at BBB(high) from DBRS and BBB from Standard & Poor's.

We welcome our new employees at Fortis Turks and Caicos and at Fortis Properties' recently acquired hotels in Alberta and British Columbia. We also welcome our employees at Caribbean Utilities to the Fortis Group of Companies. To each and every one of our 4,400 employees, we extend our thanks and congratulations for your commitment to deliver first-class service to our customers and to adhere to the highest levels of health, safety and environmental standards as we go about our daily business.

Dr. Angus Bruneau retired as Chair of the Board of Fortis Inc. at our Annual Meeting in May. Dr. Bruneau served as Chair of Fortis for the past 18 years. It was his vision that led our Company to grow from one utility, Newfoundland Power, to the Newfoundland-based international operations of today. We have seen tremendous change in both our Company and our industry over the past 20 years. One thing that never changed was Dr. Bruneau's unwavering commitment to the success of Fortis. We thank him for his leadership and commitment and extend our best wishes to him.

In recognition of the contribution Dr. Bruneau has made to our organization, Fortis pledged a $100,000 donation to Memorial University of Newfoundland in his honour. The donation was directed towards a complete remodelling of the main lecture theatre in the Engineering Building at Memorial University, which was renamed the *Angus Bruneau Engineering Lecture Theatre*. Dr. Bruneau was the founding Dean of Engineering at Memorial University.

Dedication ceremony for the Angus Bruneau Engineering Lecture Theatre *(l-r): Dr. Axel Meisen, President and Vice-Chancellor, Memorial University of Newfoundland; Dr. Angus Bruneau, past Chair of the Board, Fortis Inc.; H. Stanley Marshall, President and CEO, Fortis Inc.*

Following the retirement of Dr. Bruneau, your Board of Directors appointed Mr. Bruce Chafe as Chair of the Board of Fortis Inc. Mr. Chafe has served as a Director of Fortis since 1997. We express our thanks to all members of our Board of Directors for their continued guidance and leadership.

On February 26, 2007, Fortis entered into an agreement with Kinder Morgan, Inc. to buy Terasen Gas for a total purchase price of $3.7 billion, including the assumption of $2.3 billion in debt. Terasen Gas is the principal natural gas distribution utility in British Columbia, serving approximately 900,000 customers or 95 per cent of natural gas users in the province. Terasen Gas is a well-run utility which will give Fortis a platform for further growth in the natural gas distribution business. It will complement our electric utilities, providing value for our customers and shareholders. The acquisition, which is expected to close in mid-2007, will significantly increase the earnings of Fortis from regulated utilities and be immediately accretive to earnings per common share of Fortis.

Going forward, organic earnings growth will be driven by significant infrastructure investment at our regulated utilities in Western Canada and at our regulated and non-regulated utilities in the Caribbean. We remain focused on doing what we do best – operating efficient utilities while meeting the growing needs of our customers. Fortis will continue to seek regulated utility acquisitions in Canada, the Caribbean and the United States that provide opportunities to continue to grow our business profitably. We will also pursue growth in our non-regulated business in support of our regulated utility growth strategy.

On behalf of the Board of Directors,

Bruce Chafe
Chair of the Board
Fortis Inc.

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

VISION

VISION

In 1987, Fortis was structured as a holding company to pursue profitable growth and diversification. Today, the Corporation is an international distribution utility holding company with electric utilities serving more than 1,000,000 customers in Canada and the Caribbean region and with significant non-utility operations in non-regulated hydroelectric generation, commercial real estate and hotels.

Fortis has holdings in eight regulated electric distribution utilities in Alberta, British Columbia, Newfoundland, Prince Edward Island, Ontario, Belize, Cayman Islands and the Turks and Caicos Islands. The Corporation also owns non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. Fortis Properties, the Corporation's vehicle for non-utility growth and diversification, owns and operates commercial real estate in Atlantic Canada and hotels in seven provinces in Canada.

H. Stanley Marshall, President and CEO, Fortis Inc. (left) and Barry V. Perry, VP, Finance and CFO, Fortis Inc. (right)

On February 26, 2007, Fortis entered into an agreement with Kinder Morgan, Inc. to buy Terasen Gas, the largest natural gas distribution utility in British Columbia. The acquisition is expected to close in mid-2007.

The principal business of Fortis is and will remain the ownership and operation of regulated utilities. The first priority remains the continued profitable expansion of existing operations. The Corporation will also pursue opportunities to acquire other utilities in Canada, the Caribbean and the United States. A higher return criteria will be applied to international assets to offset the increase in the risk profile.

The non-utility business operations of Fortis support the Corporation's utility growth and acquisition strategy. Fortis Properties will continue to grow in size and profitability, providing flexibility in financial and tax planning not generally possible with respect to utilities because of regulatory and public policy constraints. Fortis will maintain approximately 15 per cent to 20 per cent of its assets in non-utility businesses.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders. The Corporation will continue to focus on three primary objectives:

i) Earnings should continue at a rate commensurate with that of a well-run Canadian utility.

ii) The financial and business risks of the overall operations of Fortis should not be substantially greater than those associated with the operation of a Canadian utility.

iii) The growth in assets and market capitalization should be greater than the average of other Canadian public corporations of similar size.

Fortis utilities provide a good mix of established, low-risk domestic operations and high-growth international assets. The corporate philosophy is to grow only if it can be done profitably. The Corporation has a strong record of profitable growth. Fortis will continue to build upon its record without significantly disturbing the risk-reward balance traditionally associated with the operation of regulated utilities.

Employees' commitment to serve customers well, combined with their knowledge and skills, fortify the reputation Fortis has achieved as an efficient utility operator. Integrity, accountability and autonomy are the core values that continue to underpin performance.

REGULATED UTILITY OPERATIONS

FortisAlberta is an electric distribution utility which owns and/or operates more than 104,000 kilometres of distribution lines and distributes electricity generated by other market participants to end-use customers in southern and central Alberta. The Company serves approximately 430,000 customers and met a peak demand of 2,584 MW in 2006.

Operating in a robust economy, FortisAlberta invested approximately $243 million, before customer contributions, in its electricity system in 2006 to improve reliability of service and meet new load growth. This investment, which represents a 47 per cent increase over the level of investment in 2005, provides the infrastructure to support Alberta's rapid growth while ensuring continued safe, reliable electricity service to customers.

Officers of FortisAlberta (l-r): Cynthia Johnston, VP, Corporate Services and Regulatory; Gary Smith, VP, Operations and Engineering; Philip Hughes, President and CEO; Karin Gashus, VP, Customer Service; James Harbilas, VP, Finance and CFO; Alan Skiffington, VP, Information Technology and CIO

Capital projects totalling approximately $116 million were undertaken to meet growth in customer demand driven by activity in the oil and gas industry and a residential housing boom. As part of the Company's multi-year program to improve system reliability, approximately $73 million was invested for capital upgrades and replacements, and to increase the capacity of its distribution network. More than 45 kilometres of heavy-load circuits were upgraded and 1,500 poles were replaced. Alternate feeder lines were built in high-growth areas to improve system reliability, including the Leduc/Nisku area which experienced a 10 per cent increase in load growth. FortisAlberta energized its 25-kilovolt ("kV") distribution line from Altalink's new Bassano substation, boosting Alberta's electricity system capacity by an additional 25 MW. This $0.6 million project enabled the Company to meet increased energy demand and improve reliability of service to residential, farm and oil sector customers in the Bassano area.

FortisAlberta completed a $100 million debenture offering in April 2006 and a $110 million debenture offering subsequent to year end. The proceeds from the offerings were used to refinance debt and to fund operating and capital expenditures to meet rapid growth within the utility's service territory.

The Company received a record Customer Satisfaction Rating of 78 per cent in 2006. Despite the operational challenges associated with substantial growth in energy demand, customers experienced, on average, 1.86 hours of outage time during the year, which represented approximately a five per cent improvement over the three-year average for the utility and was about one-half of the three-year average for the Canadian Electrical Association. The number of pre-planned outages was reduced by 19 per cent this year due to enhanced work methods and the use of innovative tools and equipment, including live-line equipment that allowed field personnel to work on many capital growth projects without service interruption.

FortisAlberta continued to introduce productivity initiatives to better serve customers. Engineering processes and work practices were revised, which reduced the time to complete construction projects and enhanced work capacity. Updated screening technology reduced the number of field visits required to locate underground cables and new equipment improved vegetation management practices, resulting in increased efficiency and higher quality work. The Company improved its ability to assign resources, bundle work and reduce employee travel time.

FortisAlberta made significant progress in improving its internal safety record during a year when more than 200 employees were hired or changed roles, including 56 employees who were assigned to high-risk line positions. The Company recorded an All-Injury Frequency Rate of 1.98 in 2006, a 29 per cent improvement from 2005, which resulted from improved work practices, increased training and investment in tools and equipment. Nineteen field offices were recognized for achieving three or more years without lost-time incidents.

Significant growth in Alberta's construction industry caused public safety concerns for FortisAlberta in 2006 as the Company experienced, on average, one public contact with its power lines daily. FortisAlberta led a Joint-Utility Safety Team with participation from the Government of Alberta and other Alberta utilities. In the fall, the Team launched a province-wide advertising campaign and a public-service television program to reinforce its message about the hazards of high-voltage lines.

The Company formed a partnership with the Alberta Birds of Prey Centre to improve reliability of service for customers. FortisAlberta has pledged $200,000 over five years to the Centre for projects directed towards helping the utility design poles and wires to prevent bird injuries and, thereby, reduce unplanned outages. The monies will also assist the Centre in its education outreach programs and its work to rescue and rehabilitate birds.

The Company improved its ability to deploy resources in the field by upgrading a computerized dispatch tool which provides control centre and field personnel with a single computerized map showing resources, facilities and work assignments. In 2007, this dispatch tool will be used in the utility's outage-management program to improve system reliability.

FortisAlberta's role in Alberta's deregulated market environment involves accountability for meter data collection of more than 200,000 meters per month, data distribution, tariff billing and load settlement for more than 80 retailers. The Automated Meter Infrastructure ("AMI") technology, an innovative system which bills customers with AMI meters on actual reads and eliminates estimated bills, was launched in December. This major technology initiative will reduce overall operating costs associated with manual meter reading and improve accuracy of revenue recognition. Early in 2007, the Company began the first phase of the AMI installation by replacing 30,000 manually read meters for residential, farm, irrigation and commercial customers. The first phase is expected to be completed by mid-2007. Pending regulatory approval, AMI meters will be installed for all customers by the end of 2010.

FortisAlberta, in partnership with the City of Airdrie, received approval for a new operations facility in Airdrie's Kingsview Business Park. The facility, expected to open in 2008, will house approximately 300 FortisAlberta employees, enabling the utility to better serve customers in the service area.

FortisAlberta invested approximately $243 million, before customer contributions, in its electricity system in 2006 to improve reliability of service and meet new load growth.

In light of Alberta's highly competitive labour market, the Company continued to focus on the recruitment and retention of employees to meet workforce requirements. An enhanced employee-referral program and increased participation in career fairs attracted candidates who filled more than 200 positions in 2006. Career development, front-line leadership workshops and ongoing technical training, such as the Journeyman Upgrade Program, have enabled FortisAlberta to further develop the knowledge and skills of its 943 employees while retaining employees who view FortisAlberta as a key contributor to their professional development.

FortisBC is an integrated regulated utility operating in the southern interior of British Columbia, serving more than 152,000 customers directly and indirectly. Its utility assets include more than 6,750 kilometres of transmission and distribution power lines and four hydroelectric generating plants with a combined capacity of 235 MW. The Company generates approximately 45 per cent of its electricity requirements with the balance met through power purchase agreements. FortisBC met a peak demand of 718 MW in 2006, which matched the historical peak set in 2004.

This year marked the first full year of operations for the Customer Contact Centre since being re-established in British Columbia in 2005. Employees answered more than 139,000 customer calls and responded to over 64,000 other contacts, including emails and letters. Incoming calls were answered, on average, within 32 seconds. The Company received a Customer Satisfaction Rating of 85 per cent in 2006, four per cent higher than last year's rating. Customer service agents were trained to respond to first-level inquiries related to energy-efficiency programs and an automated telephone notification system streamlined the customer notification process for planned outages.

Officers of FortisBC (l-r): Michael Mulcahy, VP, Customer and Corporate Services; David Bennett, VP, Regulatory Affairs and General Counsel; Don Debienne, VP, Generation; John Walker, President and CEO; Doyle Sam, VP, Transmission and Distribution; Michele Leeners, VP, Finance and CFO

A monthly meter reading schedule was implemented, which reduced the time between reading the meter and issuing a bill by five days. A meter reading route optimization project provided further efficiencies and services at no incremental cost to customers. Significant improvements continued to be made to new-customer connection times and outage emergency-response times.

FortisBC invested approximately $111 million, before customer contributions, in capital projects this year. The utility's long-term capital program responds to increased energy demand driven by customer growth and the need to enhance the reliability of its electricity system.

A number of transformer upgrades and replacements were completed in the Okanagan region. During the year, work commenced on three substations and associated transmission lines with an estimated project cost of $60 million, of which $8.1 million was invested in 2006. Distribution-line rebuilds and protection upgrades were completed to further improve reliability of service in the Kootenay region.

FortisBC experienced a record summer-peak demand of 554 MW this year, eight per cent higher than last year. A fusing and coordination initiative was launched in the Okanagan region to improve system response to power-line faults and contribute to fewer customer interruptions.

The Company invested approximately $11 million in its generation-asset Upgrade and Life-Extension ("ULE") program. The program effectively rebuilds the generating units and all auxiliary systems, extending the life of the infrastructure for at least an additional 40 years.

FortisBC operates 15 generating units in its four hydroelectric power plants. Six generating unit rebuilds have been completed under the ULE program to date. In 2006, this program resulted in an incremental increase in generating capacity of more than 20 MW for a combined generating capacity of 235 MW.

The Canal Plant Agreement (the "Agreement") between FortisBC and BC Hydro was renewed for an additional 30 years and officially came into effect in April 2006, following an extensive negotiation process. The Agreement provides electrical capacity and energy entitlements to FortisBC, Teck Cominco Metals Ltd., Columbia Power Corporation and Columbia Basin Trust.

The Company's All-Injury Frequency Rate was reduced to 1.8 from 2.0 in 2005. This improvement was a substantial achievement for the utility's 506 employees given the extensive capital projects that were undertaken in 2006.

FortisBC led a cooperative safety program in partnership with other British Columbia utilities and safety organizations to improve public awareness of electrical safety practices and potential hazards. The program was promoted through an extensive advertising campaign and included the launch of a new website, *www.coopsafetyprogram.ca*. Employees delivered electrical safety seminars to various community groups including schools and emergency responders.

FortisBC continues to address the issue of power theft and its impact on public safety and customer rates. In 2006, 46 incidents of bypassed electrical services were identified and discontinued. The Company also led the development and distribution of a joint-industry letter regarding safety issues related to copper theft from utilities.

FortisBC's utility assets include more than 6,750 kilometres of transmission and distribution power lines and four hydroelectric generating plants with a combined capacity of 235 MW.

FortisBC and the Canadian electricity industry are facing a growing shortage of skilled tradespeople, in particular power-line technicians. An aging workforce also challenges recruitment initiatives. The utility continues to support apprenticeship programs and hired seven power-line technician apprentices during the year. The Company participates in cooperative education programs. A new engineer-in-training program was developed in 2006 to strengthen the utility's engineering group and focus on employee development.

In 2006, new collective agreements were ratified with the International Brotherhood of Electrical Workers and the Canadian Office and Professional Employees Union. The agreements are effective until January 31, 2008 and January 31, 2011, respectively.

FortisBC is committed to operating its business in an environmentally responsible manner. In 2006, the utility partnered with the South Okanagan-Similkameen Invasive-Plant Society, the Boundary Weed-Management Committee and the Central Kootenay Invasive-Plant Committee on several invasive-plant control programs. The promotion of natural, appropriate vegetation controls the growth of invasive plants and trees that may interfere with the performance of the electricity system.

FortisBC worked with the Provincial Ministry of Environment and wildlife biologists to minimize power outages and reduce electrocution risk to osprey. An osprey risk-management standard was developed and implemented to reduce future electrical outages and contacts.

The Company launched its *Bright Ideas* energy-efficiency public-awareness campaign during the year. Employees were also active in the community promoting energy-efficiency initiatives, which helped customers conserve approximately 23 GWh of energy in 2006.

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 230,000 customers, or 85 per cent of electricity consumers in the Province, and met a peak demand of approximately 1,166 MW in 2006. Approximately 90 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro ("Newfoundland Hydro"). Newfoundland Power has an installed generating capacity of approximately 136 MW, of which 92 MW is hydroelectric generation.

While challenged with increased energy prices, the Company achieved a Customer Satisfaction Rating of 89 per cent in 2006. For the past 10 years, the utility has placed near the top of industry rankings for overall customer service. Initiatives focused on maximizing the quality of customer service, reducing the cost of service delivery and providing energy-efficiency information and programs to customers.

Newfoundland Power's *Bright Ideas* campaign helped customers manage their energy usage by sharing easy, practical tips on how to conserve energy in homes and businesses. Employees talked one-on-one with customers, delivered seminars to seniors and special interest groups and appeared on local television and radio broadcasts to deliver information on energy efficiency. Throughout the year, thousands of customers at more than 50 trade shows and public events received information on ways to reduce their energy consumption. The *Bright Ideas* campaign was recognized by the Newfoundland and Labrador Chapter of the International Association of Business Communicators for Marketing Excellence for its effectiveness in promoting easy and practical energy-saving tips to customers.

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

The Company also worked closely with its energy supplier, Newfoundland Hydro, to deliver advice on energy-efficiency initiatives to all customers throughout the Province. Over 1,000,000 brochures were distributed directly to customers through Newfoundland Power's billing system, trade shows and other public events.

The utility's website was enhanced to give more visibility to the importance of electrical safety and to improve public access to information. A new *KidZone* was launched on the website to give children an opportunity to learn more about electrical safety through interactive computer games. Parents and educators can access teaching tools there as well.

Wireless technology was used to improve customer response times by enabling Contact Centre employees to quickly assign customer requests to the appropriate technicians in the field. Upgrades were made to the Company's Integrated Voice Response telephone system to provide more self-serve options, such as enabling customers to request final meter readings.

More and more customers are choosing to use the Company's on-line services. Customer visits to Newfoundland Power's website increased 24 per cent in 2006 compared to 2005. The number of customers who received their bills electronically also increased by 58 per cent compared to 2005. This billing option is more convenient for customers and is cost effective, which helps keep electricity rates down.

Newfoundland Power experienced the best reliability performance in the history of the Company in 2006 with respect to the duration of outages. The Company decreased the length of outages by 12 per cent compared to 2005, which meant the electricity system was operating successfully and delivering power to customers 99.96 per cent of the time in 2006.

The Company invested approximately $60 million, before customer contributions, in its electricity system in 2006. A primary focus in improving the distribution system included the refurbishment of seven rural distribution lines with the poorest reliability performance. Three major transmission lines were also substantially rebuilt at a total cost of approximately $2.8 million. The Petty Harbour plant, commissioned in 1900 as the Province's first hydroelectric plant, received a $1.8 million overhaul this year. Small hydroelectric developments like the Petty Harbour plant enable the Company to provide low-cost, renewable electricity to customers.

The Petty Harbour plant, commissioned in 1900 as Newfoundland's first hydroelectric plant, received a $1.8 million overhaul in 2006.

Newfoundland Power developed new safety procedures and purchased innovative protective clothing to address hazards associated with high-voltage switchgear located in substations and generating plants. Safe-work procedures were implemented and new equipment was purchased to reduce the risk of injury and to improve control during wire installation near energized lines.

The Company responded to an increase in public contacts involving the electricity system. A number of incidents involved cut trees falling into power lines while other incidents involved contractors. Throughout the year, safety information and advertising efforts were increased to remind the general public, employers and contractors about the dangers involving the electricity system. Newfoundland Power partnered with Newfoundland Hydro, the Newfoundland and Labrador Construction Council, the Workplace Health, Safety and Compensation Commission and others to promote electrical safety.

Newfoundland Power's 552 employees continued to deliver quality service to customers. Training was provided to improve the leadership and coaching skills of front-line supervisors. A Benefits Strategy was implemented to ensure the continuation of a competitive benefits program at a reasonable cost and to engage employees and retirees in managing the future cost of benefits.

A long-term workforce strategy is in place to address the Company's future hiring needs should a labour shortage occur. Newfoundland Power is focused on the recruitment of power-line technicians and apprentices.

The Company continued to work towards achieving its goal to phase out polychlorinated biphenyls ("PCBs") in all oil-filled distribution equipment by 2009. PCBs were removed from 28 distribution feeders and four substations and have been phased out of all major substation equipment, such as breakers and substation transformers.

The Government of Newfoundland and Labrador recognized Newfoundland Power employees with the *2006 Environmental Award* in the Business category for their unwavering commitment to the environment. This honour was the eighth environmental award received by the Company in the past eight years.

Newfoundland Power's Bright Ideas *campaign helped customers manage their energy usage by sharing easy and practical tips on how to conserve energy in homes and businesses.*

Maritime Electric, the principal electric utility on Prince Edward Island, serves approximately 71,000 customers, or 90 per cent of electricity consumers in the Province, and met a peak demand of 216 MW in 2006. The utility owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity across the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait.

The Company purchases more than 95 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these Stations. The Point Lepreau Station will undergo an 18-month refurbishment beginning in 2008 that will extend its life by 25 years, providing additional stability with respect to long-term energy supply.

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

The remainder of off-Island energy purchases is made at market prices under an agreement with NB Power. Maritime Electric obtains the balance of its energy requirements either from its own generating plants or from on-Island wind-powered electricity generation facilities.

Maritime Electric invested approximately $27 million, before customer contributions, in 2006 primarily to improve system reliability and customer service. The new 50-MW combustion turbine generator was brought on-line in early 2006 to address issues associated with the loading of the submarine cables between Prince Edward Island and the mainland power grid. It provides increased reliability and security of energy supply. Construction commenced on a 138-kV transmission line to the eastern part of the Province to enable the utility to purchase energy from PEI Energy Corporation's new 30-MW wind farm.

In August, the Island Regulatory and Appeals Commission approved Maritime Electric's application to recover through rates the costs associated with a 39-MW Wind Power Purchase Agreement (the "Agreement") between the utility and PEI Energy Corporation. Recent legislation proclaimed by the Government of Prince Edward Island under the terms of the *Renewable Energy Act* will require Maritime Electric to obtain at least 15 per cent of its annual energy requirements from renewable sources, such as wind-powered energy, by 2010. The Agreement, in conjunction with the existing wind-energy purchase agreements, will enable the Company to reach this 15 per cent target. Maritime Electric has committed $3.6 million towards infrastructure to enable customers to benefit from on-Island wind-powered electricity generation. Further development of the Province's wind-power regime by commercial developers will be supported by the utility through infrastructure investment in its transmission system.

Maritime Electric received a Customer Satisfaction Rating of 79.5 per cent in 2006, up from 77.7 per cent last year. This year marked the 13th consecutive year that the utility's system reliability exceeded the benchmark established under the former *Maritime Electric Company Limited Regulation Act*. Customers experienced, on average, 4.96 hours of interrupted service in 2006.

Two additional customer automated-payment sites were opened this year, bringing the total number of sites to 12 across the Province. Information technology enhancements now enable customers to receive billing information via email or on-line at the Company's website.

Building on the benefits of the technology-based Geographic Information System ("GIS"), a Planned Outage System was implemented that enables Customer Service Representatives to identify and contact customers to be affected by a planned outage. The improved availability of information enables enhanced communication with customers about planned outages.

The implementation of a new Service Order System has expanded payment options for customers and improved the billing of service orders within the Customer Information System. It will also enable the future integration of work management modules and GIS data.

Maritime Electric is the principal electric utility on Prince Edward Island, serving approximately 71,000 customers, or 90 per cent of electricity consumers in the Province.

Maritime Electric continues to work closely with all levels of government to explore opportunities to protect the environment. In partnership with government and environment stakeholders, *A Bright Idea* pilot project was completed this year, whereby 95 participating households each received up to 20 compact fluorescent light bulbs. Participants each reduced their daily consumption by an average of 2.6 kilowatts per hour, translating into annual savings of 0.7 tonnes of greenhouse gas emissions per household.

As part of its Demand Side Management initiative, the Company partnered with the PEI Women's Institute to develop Island-wide holiday-lighting promotional workshops to educate customers about their energy consumption and to encourage the use of energy-efficient Light Emitting Diodes ("LED") holiday lighting.

During the year, power-line technicians received training in safe-driving skills and heavy-equipment operation, and production employees received training in power-plant operations. Maritime Electric continued to address its human resource planning issues. Fifteen employees participated in an early-retirement incentive program this year. The hiring of new apprentices and increased training for its 175 employees will ensure the Company maintains the technical skills and knowledge needed to serve customers in the future.

An Executive Safety and Environment Committee, chaired by the President and Chief Executive Officer and consisting of members of the Executive team, was established this year. Health, safety and environmental personnel provide valuable input and support to the Committee in its efforts to enhance the utility's health and safety processes.

Maritime Electric has committed $3.6 million towards infrastructure to enable customers to benefit from on-Island wind-powered electricity generation.

FortisOntario is an integrated electric utility which owns and operates the regulated distribution businesses of Canadian Niagara Power and Cornwall Electric. Its utilities serve approximately 52,000 customers mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario and met a combined peak demand of 233 MW in 2006. FortisOntario owns regulated transmission assets in the Niagara and Cornwall regions including an interconnection between New York State and Fort Erie, Ontario. The Company owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies serving more than 27,000 customers.

FortisOntario invested more than $10 million in capital projects, before customer contributions, in 2006 primarily to enhance the reliability and efficiency of its electricity systems. In Fort Erie, extensive voltage conversions and upgrades were completed to substation equipment to improve overall operating performance and life expectancy. The Fort Erie Service Centre was upgraded to a centralized system control centre for the utility's Niagara Region distribution systems.

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

Construction commenced on a new $1.4 million distribution substation in Gananoque to improve reliability. Renovations began on a facility which will serve as an upgraded and lower-cost service centre for Gananoque field employees. In Cornwall, capital work focused on new connections, including a mix of residential and three-phase commercial services. Cornwall crews also completed the reconstruction of a rural distribution feeder in support of improved system reliability and accessibility.

FortisOntario received a Customer Satisfaction Rating of 84 per cent in 2006. Customers continue to rate reliability/safe delivery of electricity and quality of service as high priorities at 94 per cent and 87 per cent, respectively. The Company once again exceeded performance standards set by the Ontario Energy Board ("OEB") with respect to response times, service connections and telephone response statistics.

A number of manual work methods were eliminated through automation and several customer service processes were modified to minimize redundancies and reduce errors and workload. The Gananoque Customer Service Centre was consolidated with the nearby Cornwall office. The Information Technology Department initiated a comprehensive information technology consolidation plan to reduce operating costs in licensing and administration and to improve technology within the main data centre.

In October, an extreme snowstorm hit Fort Erie and Port Colborne, delivering more than 30 centimetres of wet, heavy snow on fully leaved trees. All customers in Fort Erie and a third of the utility's customers in Port Colborne were directly affected by the worst October storm recorded since the 1870s. Through a significant 24/7 recovery effort, power was restored to the majority of customers within five days. Support was marshalled from several Ontario utilities, deploying close to 100 additional line technicians plus a number of tree trimmers and customer service staff to help replace approximately 100 broken poles and more than three kilometres of service lines. FortisOntario expresses thanks and appreciation to everyone who assisted with these restoration efforts. The Company made application to the OEB in January 2007 to recover the storm costs through future rate adjustments.

FortisOntario met or exceeded all of its health, safety and environment key performance targets for 2006, including zero lost-time injuries for all work locations. The *Safety First* software program was installed to track and report on training initiatives, safety incidents and work inspections. The program will be used to manage overall safety and environmental performance. A drivers' education program contributed to a 33 per cent reduction in vehicle incidents in 2006.

The Company took the first major step towards establishing an integrated occupational health, safety and environmental management system by successfully completing a system manual. Once fully implemented, the integrated system will be consistent with Occupational Health and Safety Assessment Series 18001 and International Organization for Standardization 14001 ("ISO 14001").

FortisOntario customers continue to rate reliability/safe delivery of electricity and quality of service high priorities at 94 per cent and 87 per cent, respectively, in 2006.

A history of harmonious labour relations continued with the ratification of two new labour agreements between Canadian Niagara Power and the International Brotherhood of Electrical Workers, Local 636 in the Niagara and Gananoque regions. In support of ongoing succession planning initiatives, a 360-degree assessment program was implemented to develop the leadership skills of managers. To promote employee wellness, fitness challenges and other workplace wellness programs were launched for the Company's 133 employees.

FortisOntario continues to lobby the Government of Ontario to institute a new exemption-based transfer-tax policy in Ontario's electricity distribution sector, which would include the participation of the Canadian-owned private-sector distributors. The Company continues to pursue opportunities to partner with and acquire small publicly owned utilities in an effort to grow its distribution business. FortisOntario entered into strategic service arrangements with several distribution companies to provide them with ancillary services such as finance, regulatory and human resource expertise.

FortisOntario expresses thanks and appreciation to everyone who assisted in the significant 24/7 recovery effort of restoring power to the majority of Fort Erie and Port Colborne customers within five days following the worst October storm recorded since the 1870s.

BELIZE ELECTRICITY

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving more than 71,000 customers, the utility met a peak demand of 67 MW in 2006 from multiple sources of energy including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE"), the Mexican state-owned power company, and its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Fortis holds a 70.1 per cent interest in Belize Electricity.

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

In June, Belize Electricity completed a US$33.4 million Recapitalization Plan, the proceeds from which allowed the Company to continue its capital expenditure program to improve service reliability and meet growing energy demand.

Capital investments of US$16 million were undertaken this year to upgrade and expand the electricity system to improve service performance. One major project completed was the US$2.4 million upgrade of the southern transmission line to 69 kV from 34.5 kV. The completion of this project, a subcomponent of the Fifth Power Development Project ("Power V"), helps the Company keep pace with load growth, improves energy supply quality and reduces system losses in the southern service areas of the country. Power V incorporates the majority of Belize Electricity's substation modification, reliability and process improvement initiatives.

More than 93 kilometres of new power lines were constructed to upgrade and replace aging distribution systems in order to minimize potential hurricane damage. New line extensions were also built to connect several housing and tourism development projects.

In 2006, 206 kilometres of transmission lines were upgraded to help reduce electricity system losses. With assistance from sister companies, Newfoundland Power and Caribbean Utilities, Belize Electricity's Revenue Protection Team increased its inspection of meters. As a result of these initiatives, the Company anticipates reducing system losses in 2007.

In February 2007, the Company connected to Hydro Maya Limited's 3-MW run-of-river hydroelectric facility in southern Belize. In 2006, Belize Electricity sourced 43 per cent of its energy from hydroelectricity and is able to meet the country's peak demand with local generation when necessary.

In August, a new Power Purchase Agreement ("PPA") with CFE went into effect. Under this PPA, the Mexican utility provides Belize Electricity with up to 15 MW of firm energy and up to a maximum of 40 MW on an economic basis if no firm energy is utilized. While the unit cost of firm energy has increased, due mostly to escalating oil prices, the Company has the option to purchase economic energy, if available and cheaper, before purchasing firm energy. Under the previous agreements, 25 MW of firm energy and 14 MW of energy on an economic basis, which could only be dispatched after exhausting the use of firm energy, were provided.

Belize Electricity was awarded a Customer Satisfaction Rating of 84.1 per cent in 2006. A new Customer Information and Billing System was implemented this year, which has elevated customer-care processes to generate quick reports on meter readings, payment history and other account information in reader-friendly formats at the request of customers.

A software application was developed to deliver improved eBills to customers. The revised eBills replicate the easy-to-read format of paper bills. With this application in place, the Company is able to automatically notify customers via email of approaching due dates for bill payments.

Belize Electricity was awarded a Customer Satisfaction Rating of 84.1 per cent in 2006.

Service reliability is a critical performance parameter. Line staff was trained in the use of hot stick and rubber glove techniques on energized power lines. More than half of the Company's line staff are now certified for this work, which benefits customers by reducing the number of planned power outages.

In 2006, the Environmental Management System ("EMS") continued to be implemented in several high-risk areas of the Company. Employees received practical training in ISO 14001 policies and procedures. External auditors reported that the initiatives and activities under the utility's EMS successfully addressed areas needing improvement as identified during the 2005 initial audit. Belize Electricity plans to become compliant with ISO 14001 by 2008.

In 2006, the Environmental Management System continued to be implemented in several high-risk areas of Belize Electricity as part of the Company's goal to become compliant with ISO 14001 by 2008.

Developing human resource competencies is essential to achieving high performance standards. This year, emphasis was placed on enhancing the leadership skills of management employees by identifying top performers and implementing action plans to further develop their potential to assume greater responsibilities. Operations staff participated in a training session on information technology and customer service with other Fortis utilities. The knowledge and best practices obtained from this session were integrated into improvement action plans for these operational areas.

A health and safety culture continues to be a mainstay in day-to-day operations. *Get Movin'*, a health and safety initiative, was launched to promote the importance of physical health and fitness for employees. A Drug-Free Workplace Policy was implemented as part of the utility's commitment to protect the health and safety of customers and its 254 employees. A series of public presentations on electrical safety was well received by participants and will continue in 2007.

Caribbean Utilities generates, transmits and distributes electricity to more than 22,000 customers on Grand Cayman, Cayman Islands. The Company is one of the most reliable and efficient utilities in the Caribbean region. Its electricity system has a generating capacity of 120 MW and met a record peak demand of 87 MW in October 2006.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U.

Officers of Caribbean Utilities (l-r): Lee Tinney, VP, Transmission and Distribution; Andrew Small, VP, Production; Richard Hew, President and CEO; Eddinton Powell, Senior VP, Finance & Corporate Services and CFO; Robert Imparato, Company Secretary and CGO

In November, Fortis became controlling shareholder of the Company by increasing its ownership in Caribbean Utilities to approximately 54 per cent.

Caribbean Utilities operates under a 25-year exclusive Licence with the Government of the Cayman Islands (the "Government"). The Company is entitled to earn a 15 per cent rate of return on rate base. The utility reconvened Licence renewal negotiations with the Government in November 2005 and discussions between the two parties are ongoing. The current Licence remains in full force and effect until January 2011 or until replaced with a new licence by mutual agreement.

Caribbean Utilities achieved an 87 per cent Customer Satisfaction Rating in May 2006. Customer service initiatives undertaken throughout the year included the direct marketing of convenient external payment options, such as bill payment at local banks. New automatic meters continued to be installed, which reduce reading times and increase billing accuracy. The Company's *Energy Smart* program, designed to help customers conserve energy, was further promoted. Management conducted energy conservation seminars in the summer as fuel prices escalated and directly impacted customer bills. Caribbean Utilities offers free residential and commercial energy audits to all customers as part of its *Energy Smart* activities. Electricity service was available to customers 99.92 per cent of the time in 2006.

Capital investments for the fiscal year ended April 30, 2006 totalled US$33.9 million. Major capital projects included the restoration of four hurricane-damaged generating units, totalling 16.8 MW, which are housed in a refurbished and upgraded engine room; the commissioning of a new 8.4-MW gas turbine; and the expansion of the bulk fuel storage facility at North Sound.

The Company's fiscal 2007 capital budget is US$38 million. Ongoing projects include the US$22 million purchase and installation of a 16-MW medium-speed diesel generating unit and auxiliary equipment. This unit is scheduled for installation to meet energy demand for the summer 2007.

Caribbean Utilities' commitment to excellence in employee and public safety practices remains a priority. Safety initiatives this year included the implementation of a Contractor Safety Program, revisions to energy control procedures and updates to the Employee Health and Safety Manual.

The Company has a comprehensive EMS and is ISO 14001 certified (2004 standard) for its power generation, and transmission and distribution systems. Caribbean Utilities is the only organization in the Cayman Islands that currently has ISO 14001 certification. EMS initiatives in 2006 included the shipment of more than 45,400 kilograms of scrap aluminum and 350 hurricane-damaged transformers to Florida for recycling, which generated approximately US$0.3 million in revenue. Other initiatives included ongoing emergency-preparedness planning, a continuous employee-education program and stringent environmental and structural design standards.

Caribbean Utilities continues to monitor the development of alternative-energy sources for Grand Cayman. The Company signed a non-binding memorandum of understanding with Sea Solar Power International ("SSP") in 2004 to purchase power from a prototype 10-MW ocean thermal-energy conversion plant to be commissioned by SSP in early 2009, subject to government licencing and other approvals.

With 187 employees, more than 90 per cent of whom are Caymanian, Caribbean Utilities recorded more than 12,000 employee training hours for the fiscal year ended April 30, 2006. Training initiatives included information technology instruction to a diverse group of employees, as well as a comprehensive apprenticeship program for plant operators, line staff and fleet mechanics.

The Company achieved *Investors in People* certification in early 2006. This internationally recognized standard aligns the utility's human resource strategies with its business objectives. A People Strategy Action Plan was completed, which addresses human resource issues related to recruitment and retention of key personnel, employee and leadership development, and compensation and rewards. Employee development initiatives will continue throughout 2007 as the utility strives to maintain its employer-of-choice position in the country.

Information technology projects undertaken in 2006 included the development of business continuity plans for several departments, with crisis management and emergency response procedures to follow in 2007. Other initiatives included the completion of a disaster recovery centre to protect the utility's critical server data and the installation of the TeleLink customer service system. The automated system uses interactive voice-recognition technology to provide value-added services, such as billing enquiries and credit card bill payments, via telephone.

Caribbean Utilities was honoured in January 2006 by the Edison Electric Institute of the United States with the *Emergency Recovery Award* in recognition of the Company's achievements during its electricity service restoration efforts following Hurricane Ivan in 2004. More than 140 Fortis employees helped personnel from Caribbean Utilities restore electricity service in under three months.

Caribbean Utilities' electricity system has a generating capacity of 120 MW and met a record peak demand of 87 MW in October 2006.

FORTIS TURKS AND CAICOS

On August 28, 2006, Fortis acquired two electric utilities, P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd., (collectively referred to as "Fortis Turks and Caicos"), for aggregate consideration of approximately US$90 million.

The Turks and Caicos Islands, a British Overseas Territory located about 575 miles southeast of Miami, consists of two major island groups with an area of approximately 270 square miles. The two island groups are comprised of approximately 40 islands, eight of which are inhabited. The Turks and Caicos Islands has a population of approximately 33,000 permanent residents; however, the population increases significantly during the country's peak tourism season running from October through March. About 75 per cent of inhabitants live on Providenciales, the most developed and commercialized island of the Turks and Caicos Islands.

The Turks and Caicos Islands is a world-class tourist destination that has been experiencing significant growth in high-end resort condominium development. Gross domestic product grew by approximately 14 per cent (real growth) in 2005 to US$570 million.

Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity customers, in the Turks and Caicos Islands. The Company has a combined diesel-fired generating capacity of approximately 37 MW and met a combined peak demand of 25 MW in 2006.

Fortis Turks and Caicos owns and operates a fully integrated system providing for the generation and distribution of energy in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. The Company also owns and operates an independent generating station and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036.

Fortis Turks and Caicos is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

The robust growth in energy demand is being driven by tourism and the high level of condominium and hotel development.

Energy sales on Providenciales, where the majority of customers reside, have increased, on average, 15 per cent annually for the last 12 years. The robust growth in energy demand is being driven by tourism and the high level of condominium and hotel development. While construction activity in the Turks and Caicos Islands has been vigorous for several years now, 2006 saw an accelerated pace of development due to the high level of government-funded public works initiatives.

Fortis Turks and Caicos invested US$13.8 million in capital projects this year to meet customers' energy needs and ensure system reliability given the sustained level of growth in energy demand. The first of three generator sets purchased from Guyana was installed and preparations are underway for the installation of the remaining two units. A new 35-kV substation was energized in Grace Bay to meet the energy demand created by resort construction. Three mobile generators were acquired to provide flexibility and respond to load growth on various islands of the Turks and Caicos Islands. Requisite overhauls of the diesel-generator sets were completed and a specialized engine analysis was conducted to detect engine failure or defects. A state-of-the-art fire-protection system was commissioned at the Providenciales Generating Station.

During the year, the Company completed a number of major capital initiatives in tandem with government-funded public works transportation projects. Part of the overhead distribution system was replaced with an underground system during the paving of an extensive section of roadway through the developed area of Providenciales. A new section of cable was installed between Dellis Cay and North Caicos following the dredging of a channel from the deeper water northeast of Dellis Cay to Belfield Landing on North Caicos for the development of a new commercial port. A four-kilometre distribution line was constructed to connect the new port with the Company's distribution system at Kew.

The Turks and Caicos Islands is a world-class tourist destination.

Fortis Turks and Caicos is committed to ensuring employees have the skills and expertise needed to meet the challenges of delivering safe, reliable electricity service to customers as the Turks and Caicos Islands continues to experience strong growth in energy demand. Throughout the year, training continued to be provided to meter technicians, operators, customer service agents and information systems staff. With a team of 79 employees, Fortis Turks and Caicos will continue to support employee development initiatives to ensure customers' service expectations continue to be met.

TURKS AND CAICOS ISLANDS

Location: Approximately 575 miles southeast of Miami and 70 miles north of the Dominican Republic. It consists of two island groups with an area of approximately 270 square miles. The two island groups are comprised of approximately 40 islands, eight of which are inhabited: Salt Cay, Grand Turk, South Caicos, Middle Caicos, North Caicos, Providenciales, Parrot Cay and Pine Cay. The capital is Cockburn Town, Grand Turk.

Language: English (official)

Climate: tropical, marine, moderated by trade winds, sunny and relatively dry

Natural Resources: spiny lobster, conch

Agriculture: corn, beans, cassava (tapioca), citrus fruits

Economy: Tourism and offshore financial activities are the dominant industries and there is a modest fishing industry (lobster and crayfish). The Turks and Caicos Islands is a world-class tourist destination that has been experiencing significant growth in high-end resort condominium development. Major sources of government revenue include fees from offshore financial activities and customs receipts. The Turks and Caicos Islands does not have income, corporate, capital gains, dividend, inheritance or real estate taxes.

Currency: US dollar

Legal System: Based on laws of England and Wales, with a few adopted from Jamaica and the Bahamas

Transportation: Three international airports. Miami is the main gateway and charter flights are also available from New York and Canada. The national airport offers regular flights to other Caribbean destinations. There are also flights from the Bahamas, Haiti and the Dominican Republic.

The Turks and Caicos Islands has a population of approximately 33,000 permanent residents. The population increases significantly during the country's peak tourism season running from October through March.

NON-REGULATED OPERATIONS

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these non-regulated assets is 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric facilities, located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production increased to 178 GWh in 2006, more than two-and-a-half times the level of production for 2005. The increased production was made possible through the operation of the Chalillo hydroelectric facility, which was commissioned in September 2005. BECOL sells its entire output to Belize Electricity under a 50-year PPA.

Hydroelectric production is contributing significantly to stabilizing energy prices in a country faced with escalating oil prices. Since September 2005, the Chalillo hydroelectric facility has saved Belize Electricity customers US$4 million in energy costs by providing the least-cost source of energy available. The Chalillo development has also helped with flood control. In July, the National Meteorological Service confirmed that the presence of the facility considerably minimized the impact of flood waters in San Ignacio after heavy rains.

In British Columbia, the non-regulated generating asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC.

The Environmental Impact Assessment for the Vaca facility received approval during the year. Construction of the 18-MW hydroelectric generating facility, situated approximately five kilometres downstream of Mollejon, is scheduled to commence in 2007, pending regulatory approval. It represents the final phase of the three-phase hydroelectric development plan for the Macal River. The Vaca facility is expected to enable BECOL to address the energy demands of Belize in an economic and environmentally sound manner and reduce dependence on foreign energy supply by using generation available in-country.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership.

In Ontario, non-regulated operations include the 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

With the exception of the cogeneration plant in Cornwall, the electricity produced from these facilities is sold in Ontario at market prices.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 to develop additional capacity at Abitibi-Consolidated's hydroelectric generating plant at Grand Falls-Windsor and to redevelop the forestry company's 50-hertz hydroelectric generating plant at Bishop's Falls to increase annual energy production by approximately 140 GWh to 600 GWh. The Exploits Partnership project commenced operations in November 2003. Abitibi-Consolidated continues to use the historical annual generation while the additional energy produced as a result of the project is sold to Newfoundland Hydro under a 30-year PPA. The Exploits Partnership achieved record annual production of 168 GWh in 2006.

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

In Upper New York State, the non-regulated generating assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined capacity of approximately 23 MW. The average annual 85 GWh of energy output of these modern facilities is sold at the wholesale level through a series of contracts. In June, the Dolgeville plant was shut down as a result of flooding on East Canada Creek. While the powerhouse escaped damage, recovery work was required at the plant's intake and tailrace and the plant returned to full operation within three months.

The Chalillo hydroelectric facility in Belize considerably minimized the impact of flood waters in San Ignacio after heavy rains.

Fortis Properties owns and operates 18 hotels, offering more than 3,200 rooms, in seven Canadian provinces and 2.7 million square feet of commercial office and retail space in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

In November, Fortis Properties expanded its presence in Western Canada with the acquisition of four internationally branded hotels, operating 454 rooms, in Alberta and British Columbia. The approximate $52.0 million transaction included the purchase of Holiday Inn Express and Suites, and Best Western, in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia. The hotels are leaders in their respective markets, enabling Fortis Properties to continue to build on its reputation for high-quality, well-situated hotels.

The $2.3 million, 11,000-square foot conference centre expansion at Holiday Inn Kitchener-Waterloo and the addition of a $7.8 million, 70-room tower at Holiday Inn Sarnia were officially opened in 2006. The enhanced product offerings of the hotels will increase their ability to attract larger-scale events. Fortis Properties disposed of the Days Inn in Sydney, Nova Scotia for gross proceeds of $4.5 million. The Company maintains its presence in Sydney as the owner/operator of the Delta Sydney.

Officers of Fortis Properties (l-r): Earl Ludlow, President and CEO; Neal Jackman, VP, Finance and CFO; Nora Duke, VP, Hospitality Services; Wayne Myers, VP, Real Estate

Customer Satisfaction Ratings for the Hospitality Division showed continued improvement in 2006. The Company's three Delta hotels were recognized by the brand with *Most Improved Guest Satisfaction* and *Hotel of the Year* awards for superior performance. The Delta St. John's Hotel and Conference Centre placed first in both categories.

Revenue per Available Room ("REVPAR") increased for the 11th consecutive year, reaching $72.67. REVPAR growth was primarily due to an increase in average daily room rates.

The Real Estate Division continued its strong and stable operations throughout the year. Occupancy was 94.9 per cent as of December 31, 2006, outpacing the national rate of 92.3 per cent.

Fortis Properties continues to build upon its strong tenant relationships with proactive negotiations for early tenant renewals. Long-term leasing provides for stable annual earnings and reflects the Company's commitment to customer service and product quality.

Growth in the Real Estate Division was primarily derived from completion of the $6.2 million, 57,000-square foot expansion of the Blue Cross Centre in Moncton, New Brunswick. Within four months of opening, signed lease agreements were obtained for 100 per cent of the expansion. A $60,000 incentive was received under the Government of Canada's Commercial Building Incentive Program for the expansion's energy-efficient design, which is 29.9 per cent more efficient than the Model National Energy Code for Buildings.

The Building Owners and Managers Association ("BOMA") Atlantic recognized the Maritime Centre in Halifax, Nova Scotia with the BOMA Atlantic Award of Excellence for 2006–2009. The Award acknowledges superior quality in property and facility management. Kings Place in Fredericton, New Brunswick received recognition in BOMA Atlantic's Environmental

Stewardship category for its chiller replacement project which will result in 69,000 kilowatt hours of energy being conserved each year. Brunswick Square in Saint John, New Brunswick helped a major tenant implement a composting and waste management initiative, which was also recognized in BOMA Atlantic's Environmental Stewardship category.

Customer Satisfaction Ratings for Fortis Properties' Hospitality Division showed continued improvement in 2006.

Opportunities were identified to mitigate the impact of increasing operating costs associated with higher energy prices and rising property taxes. Energy-efficiency programs, tax-assessment reviews and operational improvements helped to control costs throughout the year.

Several technology enhancements were made to improve the quality of service. More than $0.6 million was invested in the installation of new property management systems at eight of the Company's hotels. The new systems will enhance reservation and check-in services and improve property operating efficiencies. The installation of new backup software and a Storage Area Network was completed during the year. This new infrastructure will strengthen application and data management operations. In 2006, a new payroll system was installed to provide more self-service options for payroll information and improve information management.

Health and safety initiatives for the year focused on education and accountability. Ten-point safety audits were conducted for the majority of the Company's properties in Atlantic Canada and Ontario and will continue in 2007 for the remainder. On-line training modules were implemented to highlight safe work-practices and procedures and the role Fortis Properties' 1,500 employees play in creating a safe and healthy work environment.

Growth in the Real Estate Division was primarily derived from completion of the $6.2 million, 57,000-square foot expansion of the Blue Cross Centre in Moncton, New Brunswick.

A mentoring program was launched in 2006, which provides an opportunity for participants, considered to be top performers within the Company, to partner with other employees for the purpose of career and personal development.

Employee communication initiatives continue to be a priority. A corporate newsletter was launched in the spring to communicate business messages and highlight employee successes. Throughout the year, employees participated in town-hall meetings, brown-bag lunches and employee orientation sessions to learn more about the Company and their role in it.

OUR COMMUNITY

Fortis believes in the power of giving back to our communities. Each and every day, Fortis employees roll up their sleeves and work with other community-minded people to make our communities better and brighter. Here are just a few of the initiatives we were proud to support in 2006.

Our employees and their families and friends laced up their runners and hit the pavement in support of the *2006 CIBC Run for the Cure*, raising approximately $15,000 in aid of breast cancer research and treatment in addition to $25,000 pledged corporately. Since coming on board as *First Regional Sponsor in Atlantic Canada* in 2001, Fortis and our employees have pledged approximately $307,000 to the cause.

FortisAlberta employees delivered *Zap*, an electrical safety education program, to more than 5,000 elementary students. The trivia-style board game challenges young people to identify and avoid electrical hazards. The Alberta Centre for Injury Control and Research bestowed FortisAlberta with the *Injury Control Champion Award* for increasing public awareness of electrical safety.

FortisBC launched the first annual *FortisBC Wild Festival for Youth Writing and Art Contest*. More than 400 submissions were received from children who demonstrated their knowledge of wildlife and the environment through art and essays. Six winners were recognized at the *FortisBC Wild Festival for Youth*, currently the largest Canadian environmental festival solely for children.

Newfoundland Power marked its fourth anniversary of *The Power of Life Project* with a $53,000 donation for two newly renovated cancer centres in central Newfoundland. The contribution will be used to purchase chemotherapy chairs, furnishings and equipment for the centres.

The *11th Annual Maritime Electric Charity Golf Tournament* raised $30,000 for the Heart and Stroke Foundation, Canadian Cancer Society PEI Division and Children's Wish Foundation. Maritime Electric also supported a local athlete who won four medals, including a gold medal, at the 2006 World Cup Bobsleigh Championship and later competed at the Winter Olympics in Italy, finishing in fourth place, missing the bronze medal by .05 seconds!


FortisOntario raised almost $32,000 for the *2006 United Way Campaign* and was recognized by the *United Way of Greater Niagara* for its dedication and commitment to the Campaign's effort. FortisOntario also hosted the *United Way Golf Tournament* for the second straight year, raising $10,000 for worthy community initiatives.

Belize Electricity was proud to sponsor the first-ever *School Band Fest Competition* held in Belize. More than ten schools participated in the event, which raised awareness for the development of the musical talents of young Belizean students.

Caribbean Utilities was the main sponsor of the *Primary Football League*, featuring more than 300 players from 14 schools across Grand Cayman. Many Company employees volunteered as coaches and referees throughout the season.

Fortis Turks and Caicos continued to support several cultural activities and events such as the *South Caicos Regatta* and the local *Conch Festival*. The Company also sponsored *Education and You*, a local television program highlighting the value of education.

Fortis Properties partnered with the *Military Family Service Centre* in Newfoundland and Labrador to fill gift boxes for military personnel serving in Afghanistan. More than 100 boxes were packaged as a result of the collaborative efforts of Fortis Properties employees and military personnel.

Thank you to our employees and to all volunteers who contribute to powering our communities.

MANAGEMENT DISCUSSION AND ANALYSIS

Dated March 15, 2007

The following material should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in the Fortis Inc. 2006 Annual Report. This material has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations relating to Management Discussion and Analysis. Financial information in this material has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified. Fortis Inc. ("Fortis" or the "Corporation") includes forward-looking statements in this material which reflect management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as "anticipate", "believe", "expects", "intend" and similar expressions have been used to identify the forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to the Corporation's management. Forward-looking statements involve significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations generally. Such risk factors or assumptions include, but are not limited to, regulation, energy prices, general economic conditions, weather, derivatives and hedging, capital resources, loss of service area, licences and permits, environment, insurance, labour relations, human resources and liquidity risk. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. For additional information with respect to certain of these risks or factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities including those factors described under the heading "Business Risk Management" in the following Management Discussion and Analysis for the year ended December 31, 2006. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

A discussion of the financial condition and results of operations for the fourth quarter of 2006 is contained in the Corporation's Interim Management Discussion and Analysis for the three and twelve months ended December 31, 2006 dated and filed on SEDAR at www.sedar.com on February 8, 2007.

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

Corporate Overview and Strategy

Fortis is principally a diversified, international distribution utility holding company with investments primarily in regulated distribution utilities in Canada and the Caribbean region. The Corporation serves more than 1,000,000 electricity customers and meets a combined peak demand of approximately 5,100 megawatts ("MW"). Fortis also owns and operates non-regulated generation assets, commercial real estate and hotels.

The vision of Fortis is to be a world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, the Corporation pursues growth through acquisitions. The key objectives of Fortis are:

- Earnings should continue at a rate commensurate with that of a well-run Canadian utility.
- The financial and business risks of the overall operations of Fortis should not be substantially greater than those associated with the operation of a Canadian utility.
- The growth in assets and market capitalization should be greater than the average of other Canadian public corporations of similar size.

The key goals of the Corporation's regulated utilities are to operate sound distribution systems and to deliver safe, reliable electricity to customers at reasonable rates. The Corporation's core business is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The Corporation's regulated utilities are segmented between Regulated Utilities – Canadian and Regulated Utilities – Caribbean. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates associated with the rate-setting mechanisms.

Fortis also holds investments in non-regulated generation assets and commercial real estate and hotels, which are treated as two separate segments. The Corporation has non-regulated generation assets operating in three countries with a combined generating capacity of 195 MW, principally hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties Corporation ("Fortis Properties") to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and to allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility and enhance shareholder return.

The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary briefly describes the operations included in each of the Corporation's operating and reportable segments.

Regulated Utilities – Canadian

The following summary describes the Corporation's interests in Regulated Utilities in Canada by utility:

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 430,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia serving more than 152,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 235 MW. Included with the FortisBC component of the Regulated Utilities – Canadian segment are the non-regulated operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC's assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited (''PLP"). PLP was purchased by Fortis through an indirect subsidiary on May 31, 2005. Effective January 1, 2007, PLP was amalgamated with FortisBC Inc. as part of an internal corporate reorganization.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 230,000 customers. Newfoundland Power has an installed generating capacity of 136 MW, of which 92 MW is hydroelectric generation.

d. *Maritime Electric:* Maritime Electric is the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 71,000 customers. Maritime Electric also maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined capacity of 150 MW.

e. *FortisOntario:* FortisOntario provides an integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement entered into in April 2002. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000 serving more than 27,000 customers.

Regulated Utilities – Caribbean

The following summary describes the Corporation's interests in Regulated Utilities in the Caribbean by utility:

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving more than 71,000 customers. The Company has an installed generating capacity of 37 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity (December 31, 2005 – 68.5 per cent).

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 22,000 customers. The Company has an installed generating capacity of 120 MW. On November 7, 2006, Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities' balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis will consolidate Caribbean Utilities' financial statements on a two-month lag basis and will include Caribbean Utilities' January 31, 2007 balance sheet and statements of earnings and cash flows for the three-month period ended January 31, 2007. During 2006 and 2005, the statements of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on a two-month equity lag basis.

c. *P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively referred to as "Fortis Turks and Caicos"):* Fortis Turks and Caicos was acquired on August 28, 2006 by Fortis through a wholly owned subsidiary. Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity customers, in the Turks and Caicos Islands and has an installed diesel-fired generating capacity of approximately 37 MW. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Non-Regulated – Fortis Generation

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

a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.

b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through a wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric plants in central Newfoundland. Upon the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties now directly holds the 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. Previously, the 51 per cent interest was held by CNE Energy Inc. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership, a wholly owned partnership of FortisBC Inc.

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 18 hotels with more than 3,200 rooms in seven Canadian provinces and 2.7 million square feet of commercial real estate in Atlantic Canada. Included are the four hotels in Alberta and British Columbia acquired by Fortis Properties on November 1, 2006.

Corporate

The Corporate segment captures expense and revenue items not specifically related to any operating segment. Included in the Corporate segment are finance charges, including interest on debt incurred directly by Fortis and dividends on preference shares classified as long-term liabilities, foreign exchange gains or losses, dividends on preference shares classified as equity, other corporate expenses net of recoveries from subsidiaries, interest and miscellaneous revenues, and corporate income taxes.

Financial Highlights

For the Years Ended December 31st

	2006	2005	Variance *(%)*
Net earnings applicable to common shares *($ millions)*	**147.2**	137.1	7.4
Basic earnings per common share *($)*	**1.42**	1.35	5.2
Diluted earnings per common share *($)*	**1.37**	1.24	10.5
Weighted average # of common shares outstanding *(millions)*	**103.6**	101.8	1.8
Revenue and equity income *($ millions)*	**1,471.7**	1,441.5	2.1
Dividends paid per common share *($)*	**0.67**	0.59	13.6
Return on average common shareholders' equity *(%)*	**11.87**	12.40	(4.3)
Total assets *($ millions)*	**5,447.4**	4,597.1	18.5
Cash flow from operations *($ millions)*	**263.1**	303.6	(13.3)

Acquisitions: On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all issued and outstanding shares of Fortis Turks and Caicos for aggregate consideration of approximately $97.7 million (US$87.8 million). Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity customers, in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia for an aggregate purchase price of approximately $52 million. The four hotels acquired were the Holiday Inn Express and Suites, and Best Western in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia. The acquisition increased the hospitality operations of Fortis Properties by 454 rooms.

On November 7, 2006, Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities for $55.7 million (US$49.0 million), including acquisition costs, and now owns approximately 54 per cent of the Company.

On February 1, 2005, Fortis Properties acquired three Greenwood Inn hotels located in Manitoba and Alberta for approximately $63 million. On May 31, 2005, Fortis, through an indirect wholly owned subsidiary, acquired all issued and outstanding common and preference shares of PLP for $3.7 million. Effective January 1, 2007, PLP was amalgamated with FortisBC Inc. as part of an internal corporate reorganization.

Key Trends and Risks: The recent downward trend of long-term interest rates in Canada has negatively impacted the allowed rates of return on common shareholders' equity ("ROEs") used to set customer rates at the Corporation's three largest regulated utilities. During the fourth quarter of 2006, the allowed ROEs at FortisAlberta, FortisBC and Newfoundland Power were reduced, for the purpose of setting customer rates in 2007, in accordance with the automatic adjustment formulas approved by their respective regulators. The chart below highlights the trend in regulator-allowed ROEs for the purpose of setting customer rates at the above named utilities since 2004:

Regulator-Allowed ROEs

(%)	2004	2005	2006	2007
FortisAlberta	9.50	9.50	8.93	8.51
FortisBC	9.76	9.43	9.20	8.77
Newfoundland Power	9.75	9.24	9.24	8.60

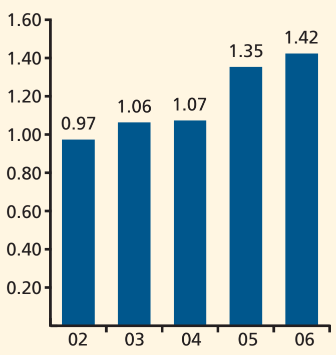
The impact on the Corporation's earnings of decreased allowed ROEs has largely been offset by increasing rate bases and energy sales and the realization of operating cost efficiencies.

Economic growth in the province of Alberta has been robust, translating into strong customer and sales growth in FortisAlberta's service territory. This service territory largely surrounds Calgary and Edmonton and includes the corridor between these cities. A healthy provincial economy and population growth in the Okanagan region of British Columbia has favourably impacted customer and sales growth at FortisBC over the past few years. As a result, organic earnings growth derived from net investment in utility infrastructure (also known as rate base) at the Corporation's Canadian regulated electric utilities is expected to be primarily driven by FortisAlberta and FortisBC. The Corporation's other Canadian regulated electric utilities – Newfoundland Power, Maritime Electric and FortisOntario – operate in more mature, stable environments resulting in slower earnings growth.

The Corporation's acquisition of Fortis Turks and Caicos and increased ownership in Caribbean Utilities to an approximate 54 per cent controlling interest during the second half of 2006 (see "Acquisitions"), has seen the percentage of the Corporation's regulated assets in the Caribbean region of total regulated assets increase from approximately 10 per cent at December 31, 2005 to approximately 18 per cent at December 31, 2006. The rate of return achieved on rate base assets is higher in the Caribbean region compared to those achieved in Canada. The higher return is correlated with increased operating risks associated with such factors as local economic, political and weather conditions. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential hurricane damage and related business interruption. While Caribbean Utilities was significantly impacted by Hurricane Ivan, a Category V storm which struck in September 2004, service was restored, assets rebuilt and insurance proceeds received within management's expectations considering the magnitude of the damage.

The key business risk to Fortis is regulatory risk. The Corporation's utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. In 2005 and 2006, FortisAlberta reached regulator-approved Negotiated Settlement Agreements with stakeholders associated with the Company's 2005 and 2006/2007 Distribution Access Tariff Applications, respectively. Similarly at FortisBC, a regulator-approved Negotiated Settlement Agreement was reached relating to FortisBC's 2006 Revenue Requirements Application. Achieving regulator-approved Negotiated Settlement Agreements eliminated the cost of full-scale public hearing processes. Although the potential receipt of an adverse regulatory decision may materially impact the ability of any utility to recover the cost of providing its services and achieve a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of the Corporation's operations. For a complete discussion of the Corporation's business risks, see the "Business Risks" section of this Management Discussion and Analysis.

Basic Earnings per Common Share *($)*



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved record net earnings applicable to common shares of $147.2 million in 2006, a 7.4 per cent increase over net earnings applicable to common shares of $137.1 million last year. Basic earnings per common share were $1.42, a 5.2 per cent increase over basic earnings per common share of $1.35 last year.

Earnings in 2005 included a $7.9 million, or $0.08 per common share, after-tax gain resulting from the settlement of contractual matters between FortisOntario Inc. and Ontario Power Generation Inc. (the "Ontario Settlement"). Growth in earnings was primarily driven by strong electricity sales growth at FortisAlberta and FortisBC, lower corporate income taxes at FortisAlberta, improved non-regulated hydroelectric generation in Belize, earnings growth at Fortis Properties, the overall 11 per cent increase in electricity rates at Belize Electricity, effective July 1, 2005, and four months of earnings contribution from Fortis Turks and Caicos. The increase was partially offset by lower average wholesale energy prices in Ontario and higher corporate costs.

Revenue and Equity Income: Revenue, including equity income from Caribbean Utilities, increased 2.1 per cent to approximately $1.47 billion from approximately $1.44 billion last year; however, revenue at FortisAlberta last year included approximately $19.7 million largely related to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments. The increase in revenue was largely driven by electricity sales growth at FortisAlberta and FortisBC, electricity rate increases at FortisBC and Belize Electricity and four months of revenue contribution from Fortis Turks and Caicos, partially offset by lower average wholesale energy prices in Ontario. Equity income from Caribbean Utilities was $1.7 million lower than last year; however, equity income last year included a $1.1 million positive adjustment related to a change in Caribbean Utilities' accounting practice for recognizing unbilled revenue. Excluding this adjustment, equity income for Caribbean Utilities decreased $0.6 million due to foreign currency translation impacts.

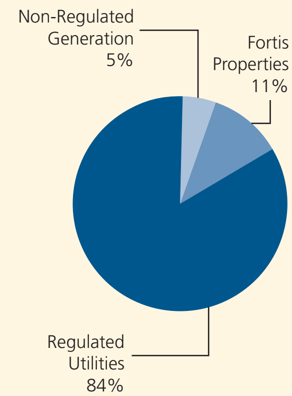
Dividends: Dividends paid per common share increased to 67 cents in 2006 from 59 cents last year. Commencing with the fourth quarter dividend paid on December 1, 2006, Fortis increased its quarterly common share dividend 18.75 per cent to 19 cents from 16 cents. The Corporation's dividend payout ratio was 47.2 per cent in 2006 compared to 43.7 per cent last year. Commencing with the second quarter dividend payable on June 1, 2007, Fortis increased its quarterly common share dividend 10.5 per cent from 19 cents per common share to 21 cents per common share.

Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 11.87 per cent in 2006 compared to 12.40 per cent last year.

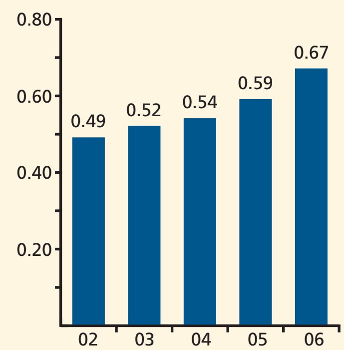
Asset Growth: Total assets increased 18.5 per cent to approximately $5.45 billion at year-end 2006 compared to $4.60 billion at year-end 2005. The increase was driven by the impact of consolidating the Corporation's investment in Caribbean Utilities, upon acquiring controlling ownership, compared to the previous method of equity accounting, and the purchase of Fortis Turks and Caicos. Asset growth associated with Caribbean Utilities and Fortis Turks and Caicos, including goodwill, was approximately $411 million year over year. The remaining growth in assets of $439 million was primarily due to the Corporation's continued investment in electricity systems, driven by the capital expenditure programs at FortisAlberta and FortisBC, and the acquisition of four hotels in Western Canada.

Cash Flow from Operations: Cash flow from operations, after working capital adjustments, was $263.1 million in 2006, 13.3 per cent lower than $303.6 million last year. Cash flow from operations, after working capital adjustments, during 2005 included the $10 million ($7.9 million after-tax) Ontario Settlement gain and a corporate income tax refund and related interest at Newfoundland Power of approximately $9 million. The decrease in cash flow from operations, after working capital adjustments, was primarily due to: (i) timing differences between when transmission costs were paid and transmission revenues were collected at FortisAlberta; (ii) higher cash taxes paid at FortisAlberta related to the previous taxation year; (iii) the payment of a $5.9 million corporate income tax deposit at Maritime Electric; (iv) the impact of lower average wholesale energy prices in Ontario; and (v) the timing of amounts due from customers, income taxes payable and accounts payable at Maritime Electric and FortisOntario. The decrease was partially offset by the recovery of higher amortization expense through customer rates at FortisBC, the impact of increased electricity rates at Belize Electricity, higher earnings at BECOL due to the operation of the Chalillo storage facility and improved hydrology, and earnings contribution from Fortis Turks and Caicos.

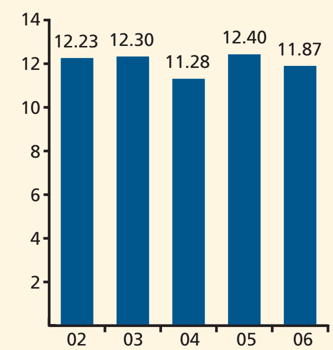
Total Revenue
(year ended December 31, 2006)



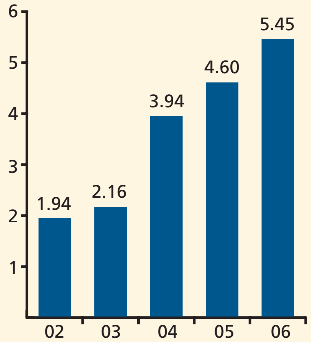
Dividends Paid per Common Share *($)*



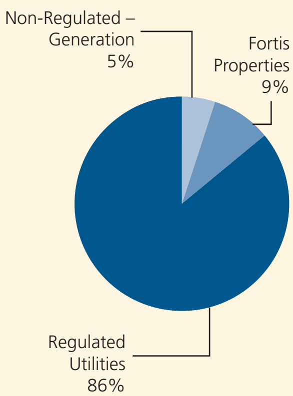
Return on Average Common Shareholders' Equity *(%)*



Total Assets *($ billions)*
(year ended December 31, 2006)



Total Assets
(year ended December 31, 2006)



2006 Capital Expenditures: During 2006, consolidated electric utility capital expenditures, before customer contributions ("gross electric utility capital expenditures"), were $483.1 million. Including $16.9 million of capital expenditures related to hotel and real estate properties, total consolidated capital expenditures were $500 million. Capital investment at FortisAlberta and FortisBC was approximately $354 million in total, representing approximately 73 per cent of gross consolidated electric utility capital expenditures. Much of this capital investment was driven by robust customer growth and the need to enhance the reliability of electricity systems. Capital expenditures at Fortis Properties primarily related to the completion of the expansions to Holiday Inn Sarnia, Holiday Inn Kitchener-Waterloo and Blue Cross Centre in Moncton.

Financing: During 2006, Fortis and its subsidiaries raised approximately $605 million of capital from a combination of preference share, common share and long-term debt issues and drawings on long-term credit facilities. A portion of the drawings on long-term credit facilities were repaid with proceeds from a 5.40% 30-year $100 million unsecured debenture issue by FortisAlberta in April 2006 and with partial proceeds from the $125 million 4.90% First Preference Share issue by the Corporation in September 2006. Consolidated drawings under long-term credit facilities were incurred largely to finance the capital expenditure programs at the regulated utilities; to finance, in part, the acquisitions of Fortis Turks and Caicos, the four hotels in Western Canada and the additional 16 per cent ownership interest in Caribbean Utilities; to fund an equity injection into one of the Corporation's Western Canadian utilities; and for general corporate purposes. In November 2006, Fortis also issued 5.50% 10-year US$40 million of unsecured subordinated convertible debentures to fund, in part, the acquisition of the additional 16 per cent ownership interest in Caribbean Utilities. These financings were completed at attractive rates and reflect investors' continued positive response to the Corporation's business strategy.

Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings
Years Ended December 31st

($ millions)	**2006**	2005	Variance
FortisAlberta	**41.4**	36.1	5.3
FortisBC [(1)]	**27.4**	24.6	2.8
Newfoundland Power	**30.1**	30.7	(0.6)
Maritime Electric	**9.8**	9.1	0.7
FortisOntario	**4.0**	4.3	(0.3)
Regulated Utilities – Canadian	**112.7**	104.8	7.9
Belize Electricity	**10.4**	8.0	2.4
Caribbean Utilities [(2)]	**9.7**	11.4	(1.7)
Fortis Turks and Caicos [(3)]	**3.5**	–	3.5
Regulated Utilities – Caribbean	**23.6**	19.4	4.2
Total Regulated Utilities	**136.3**	124.2	12.1
Non-Regulated – Fortis Generation	**26.7**	29.6	(2.9)
Non-Regulated – Fortis Properties	**18.7**	14.1	4.6
Corporate	**(34.5)**	(30.8)	(3.7)
Net Earnings Applicable to Common Shares	**147.2**	137.1	10.1

(1) Includes results for PLP from May 31, 2005, the date of acquisition of PLP by Fortis, through an indirect wholly owned subsidiary. Effective January 1, 2007, PLP was amalgamated with FortisBC Inc. as part of an internal corporate reorganization.

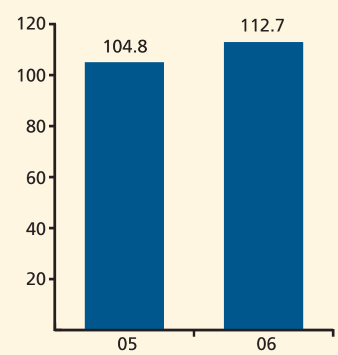
(2) On November 7, 2006, Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities' balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis. During 2006 and 2005, the statements of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on a two-month equity lag basis.

(3) On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all issued and outstanding shares of Fortis Turks and Caicos. Financial results for Fortis Turks and Caicos are from August 28, 2006.

Regulated Utilities

The Corporation's primary business is regulated utilities. The regulated earnings in Canada and the Caribbean represented approximately 75 per cent of the Corporation's earnings from its operating segments in 2006 (2005 – 74 per cent). Total regulated assets represented approximately 86 per cent of the Corporation's total assets as at December 31, 2006 (December 31, 2005 – 85 per cent). As no one utility is expected to contribute more than 25 per cent of operating earnings and cash flow of the Corporation, the effect of any single adverse regulatory event is mitigated.

Regulated Earnings – Canadian *($ millions)*



Regulated Utilities – Canadian

Regulated Utilities – Canadian earnings during 2006 were $112.7 million (2005 – $104.8 million), which represented approximately 83 per cent (2005 – 84 per cent) of the Corporation's total regulated earnings. Regulated Utilities – Canadian assets were approximately 82 per cent of the Corporation's total regulated assets as at December 31, 2006 (December 31, 2005 – 90 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31st	2006	2005	Variance
Energy Deliveries *(GWh)*	**14,851**	14,445	406
($ millions)			
Revenue	**250.8**	259.8	(9.0)
Operating Expenses	**115.2**	113.0	2.2
Amortization	**68.8**	61.4	7.4
Finance Charges	**30.1**	24.2	5.9
Corporate Taxes	**(4.7)**	25.1	(29.8)
Earnings	**41.4**	36.1	5.3

Regulation: FortisAlberta is regulated by the Alberta Energy Utilities Board ("AEUB"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). FortisAlberta operates under cost of service regulation as prescribed by the AEUB. Rate orders issued by the AEUB establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields and is based on a deemed capital structure of 63 per cent debt and 37 per cent equity. As a result of the operation of the automatic adjustment formula, FortisAlberta's allowed ROE for 2006 was 8.93 per cent, down from 9.50 per cent in 2005.

On June 29, 2006, FortisAlberta received approval from the AEUB of the 2006/2007 Negotiated Settlement Agreement associated with the Company's 2006/2007 Distribution Access Tariff Application. The 2006/2007 Negotiated Settlement Agreement, effective January 1, 2006 and based on an allowed ROE of 8.93 per cent for 2006, provided for distribution revenue requirements, excluding miscellaneous revenue and adjustment riders, of $217.1 million for 2006 and $228.2 million for 2007. These items translated into a 1.9 per cent reduction in distribution rates in 2006 and a 0.7 per cent increase in distribution rates in 2007. The revenue requirements reflect AEUB-approved forecast operating expenses of $100.8 million for 2006 and $100.1 million for 2007. Additional operating expenses of $13.0 million in 2006 and $13.5 million in 2007 will be collected by separate rate riders during those years. The revenue requirements also reflect AEUB-approved forecast capital expenditures of approximately $184.5 million, before customer contributions of $23.3 million, for 2006, and approximately $191.2 million, before customer contributions of $24.0 million, for 2007. Additionally, the AEUB-approved 2006/2007 Negotiated Settlement Agreement included forecast contributions to Alberta Electric System Operator ("AESO") projects of $10.7 million in 2006 and $10.0 million in 2007. The AESO contributions represent payments made to the AESO for investment in transmission facilities that are needed for reliability or contingency planning in accordance with the AESO Terms and Conditions of Service.

During the second quarter of 2006, FortisAlberta recorded the impact of the AEUB-approved 2006/2007 Negotiated Settlement Agreement. During 2006, the AEUB-approved 2006/2007 Negotiated Settlement Agreement resulted in a $4.2 million reduction in revenue as a result of providing for the difference between interim rates and those in the AEUB-approved 2006/2007 Negotiated Settlement Agreement, which will be refunded to customers in 2007 as ordered by the AEUB.

The AEUB-approved 2006/2007 Negotiated Settlement Agreement also resulted in changes in amortization rates and pension and income tax accounting methodologies. The move to the taxes payable method for federal income taxes simplified FortisAlberta's accounting for income taxes and reduced the Company's revenue requirements for 2006 and 2007, as future income tax expenses are no longer recovered in current customer distribution rates, but are recovered in customer distribution rates when they become payable.

Earnings: FortisAlberta's earnings were $5.3 million higher than last year, driven by lower corporate income taxes, increased energy deliveries and reduced revenue deferrals, partially offset by higher amortization costs, finance charges and operating expenses, and the impact of the 1.9 per cent decrease in distribution rates. Also, last year's results included earnings related to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments.

Energy Deliveries: Energy deliveries were 406 GWh, or 2.8 per cent, higher than last year. The increase was primarily due to growth in the number of customers in the residential, commercial, industrial and oilfield sectors as a result of a strong provincial economy. The Company added approximately 15,000 customers during the year, bringing the total number of customers at FortisAlberta to approximately 430,000.

Revenue: Revenue was $9.0 million lower than last year; however, revenue last year included approximately $19.7 million related largely to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments. Revenue also decreased $4.2 million related to the 1.9 per cent decrease in distribution rates, effective January 1, 2006. These items were partially offset by the $7.8 million impact of increased energy deliveries, reduced revenue deferrals of $4.6 million, increased franchise fee revenue of $1.7 million and the recognition of $1.0 million of revenue during the first quarter of 2006 upon AEUB approval of the Company's 2004 AESO Charges Deferral Account Application. As a result of the AEUB-approved 2005 Negotiated Settlement Agreement, approximately $3.0 million of revenue related to future income taxes collected in customer rates was deferred last year. No similar revenue deferral was recorded in 2006.

Expenses: Operating expenses were $2.2 million higher than last year, primarily due to higher labour, employee benefit and contracted manpower costs, partially offset by an increase in the amount of labour and overhead costs charged to capital projects as a result of FortisAlberta's intensive capital program. Labour costs increased due to higher salaries and additional employees. Employee benefit costs increased primarily due to the expensing of employer contributions associated with the defined benefit pension plan, partially offset by the recording of other post-employment benefit and supplemental pension plan expenses on a cash basis in 2006 compared to the accrual basis in 2005. This change in pension accounting methodology resulted from the AEUB-approved 2006/2007 Negotiated Settlement Agreement. Contracted manpower costs associated with brushing and meter reading activities increased as a result of higher contracted labour rates due to Alberta's inflationary economy. An increase in corporate governance activities during 2006, related to compliance with Multilateral Instrument 52-109, also contributed to higher contracted manpower costs.

Amortization costs were $7.4 million higher year over year, primarily due to an increase in capital assets, largely the result of load growth within FortisAlberta's service territory, combined with the impact of higher overall amortization rates that resulted from the AEUB-approved 2006/2007 Negotiated Settlement Agreement.

Finance charges were $5.9 million higher year over year, primarily due to higher debt levels arising from increased drawings under the Company's committed unsecured credit facility and the issuance of long-term debt to finance capital projects required to satisfy FortisAlberta's obligations to serve its customers. On April 21, 2006, FortisAlberta issued $100 million of unsecured debentures bearing interest at 5.40 per cent per annum, due April 21, 2036. The net proceeds of the offering were used primarily to repay existing indebtedness on FortisAlberta's committed unsecured credit facility.

Corporate taxes were $29.8 million lower than last year. The decrease was primarily due to increased deductions taken for corporate income tax purposes in excess of amounts taken for accounting purposes in 2006 as compared to 2005 and the impact of lower earnings before corporate income taxes. The difference in the deductions taken for corporate income tax purposes and those taken for accounting purposes in 2006 was accounted for entirely by the taxes payable method compared to the use in 2005 of the tax liability method for federal income taxes and the taxes payable method for provincial income taxes. The change in the income tax accounting methodology as a result of the AEUB-approved 2006/2007 Negotiated Settlement Agreement resulted in the cessation of recognizing future income tax expense for federal income tax, which would have partially offset the effects of the timing differences.

Outlook: Energy sales for FortisAlberta are heavily influenced by oil and gas sector activity and overall economic conditions within the Company's service territory. With commodity prices in the oil and gas sector expected to remain high, the Gross Domestic Product ("GDP") in Alberta is forecasted to grow by 4.7 per cent in 2007. Growth in energy deliveries at FortisAlberta is estimated at 3.0 per cent for 2007.

The Company's 2007 distribution revenue requirement, as approved in the 2006/2007 Negotiated Settlement Agreement, was based upon using the 2006 allowed ROE of 8.93 per cent. FortisAlberta's allowed ROE has been reduced to 8.51 per cent, effective January 1, 2007, due to the impact of lower long-term Canada bond yields on the automatic adjustment formula used to calculate the allowed ROE. As a result of the lower allowed ROE, FortisAlberta expects it will have to refund approximately $1.9 million of the revenue collected in base rates in 2007 to customers in future rates by including this refund in its 2008/2009 Distribution Access Tariff Application.

FortisAlberta expects gross capital expenditures during 2007 to increase to $255.6 million, up from $191.2 million as previously forecasted. The increase is primarily driven by customer growth and will be included in FortisAlberta's 2008 rate application for the purpose of setting customer rates for that year.

FortisAlberta intends to file its 2008/2009 Distribution Access Tariff Application during the second quarter of 2007 for AEUB approval of customer rates and capital expenditures for 2008 and 2009.

FortisBC

Financial Highlights

Years Ended December 31st	**2006**	2005	Variance
Electricity Sales *(GWh)*	**3,038**	2,968	70
($ millions)			
Revenue	**215.6**	194.7	20.9
Energy Supply Costs	**67.6**	60.4	7.2
Operating Expenses	**63.1**	64.8	(1.7)
Amortization	**27.3**	19.0	8.3
Finance Charges	**23.4**	18.5	4.9
Corporate Taxes	**6.8**	7.4	(0.6)
Earnings	**27.4**	24.6	2.8

Regulation: FortisBC is regulated by the British Columbia Utilities Commission ("BCUC"), which administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia). FortisBC operates under both cost of service regulation and a performance-based rate-setting ("PBR") methodology as prescribed by the BCUC. The Company applies to the BCUC for annual revenue requirements based on estimated cost of service. The PBR framework allows for the equal sharing between customers and the Company of variances above or below the allowed ROE within a prescribed band. The PBR framework is subject to change as the Company's regulatory framework evolves. FortisBC's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields and is based on a deemed capital structure of 60 per cent debt and 40 per cent equity.

In June 2005, a British Columbia utility applied to the BCUC for, among other things, a review of the current ROE mechanism applicable to regulated utilities in British Columbia. On March 2, 2006, the BCUC issued an order approving adjustments to the ROE mechanism, which resulted in the 2006 ROE for FortisBC increasing from 8.69 per cent to 9.20 per cent.

On May 23, 2006, FortisBC received approval from the BCUC of the 2006 Negotiated Settlement Agreement associated with the Company's 2006 Revenue Requirements Application. The 2006 Negotiated Settlement Agreement, effective January 1, 2006 and based on an allowed ROE of 9.20 per cent, resulted in a 5.9 per cent increase in electricity rates, an increase in the Company's composite amortization rate from 2.6 per cent to 3.2 per cent and an increase in the amount of capitalized overhead from approximately 9 per cent of BCUC-approved 2005 forecast gross operating and maintenance expenses to 20 per cent of BCUC-approved 2006 forecast gross operating and maintenance expenses. Additionally, a new PBR mechanism for the years 2006 through 2008, and optionally for 2009, was approved to allow a two percentage point band around the allowed ROE, whereby variances (adjusted for certain cost variances which flow through to customer electricity rates) as a result of actual financial performance, positive or negative, will be shared equally between customers and the Company. If the variance exceeds the two percentage point band, the excess will be placed in a deferral account for review and disposition during the next rate-setting process. The 5.9 per cent electricity rate increase was primarily driven by the Company's ongoing capital expenditure program and was the same as the refundable interim electricity rate increase previously approved by the BCUC.

On April 12, 2006, the amended and restated Canal Plant Agreement ("CPA") between FortisBC and BC Hydro became effective and continues in force until terminated by any of the parties upon giving not less than five years' notice at any time on or after December 31, 2030. The CPA governs the coordinated operations of seven major hydroelectric plants owned by FortisBC, BC Hydro, Teck Cominco Metals Ltd. and CPC/CBT.

Earnings: FortisBC's earnings were $2.8 million higher than last year. The increase was due to the 5.9 per cent increase in electricity rates, effective January 1, 2006, electricity sales growth, lower operating expenses and lower corporate income taxes, partially offset by increased amortization costs, higher finance charges and lower other revenue.

Electricity Sales: Electricity sales were 70 GWh, or 2.4 per cent, higher than last year. Sales growth was primarily attributable to continued customer growth in the Okanagan area.

Revenue: Revenue was $20.9 million higher than last year, primarily due to the 5.9 per cent increase in electricity rates, effective January 1, 2006, customer growth, higher revenue contributions of $3.1 million from non-regulated operating, maintenance and management services and PLP, and increased management fees on third-party contracts of $0.9 million. The increase was partially offset by lower other revenue due to increased PBR-incentive adjustments owing to customers of $3.7 million as a result of the new PBR mechanism approved by the BCUC, effective January 1, 2006.

Expenses: Energy supply costs were $7.2 million higher than last year, primarily as a result of increased electricity sales, higher average prices for purchased power and a higher proportion of purchased energy versus energy generated from Company-owned plants. Energy supply costs for 2006 included an accrual of $1.2 million to recognize expected insurance proceeds, which directly offset the incremental power purchase costs incurred in 2006 due to a turbine failure at the Lower Bonnington generation plant. Hydroelectric facilities owned by FortisBC generate approximately 45 per cent of the energy and 30 per cent of the capacity necessary to meet existing customer demand. The majority of the additional energy and capacity required to meet existing customer demand is purchased under firm, long-term power purchase contracts. Any remaining energy and capacity required is purchased on the open market and is subject to fluctuations in market rates.

Operating expenses were $1.7 million lower than last year. The decrease was primarily due to increased capitalized overhead costs of $5.0 million, as a result of the BCUC-approved 2006 Negotiated Settlement Agreement, effective January 1, 2006, and operating cost efficiencies of approximately $0.3 million, partially offset by increased water fees and property taxes of $0.9 million, higher PLP operating expenses and expenses related to non-regulated operating, maintenance and management services totalling approximately $2.2 million, and a $0.5 million provincial capital tax appeal refund recorded during the second quarter of 2005.

Amortization costs were $8.3 million higher than last year, primarily due to the increase in the Company's composite amortization rate from 2.6 per cent to 3.2 per cent as a result of the BCUC-approved 2006 Negotiated Settlement Agreement, effective January 1, 2006, and an increase in FortisBC's capital assets due to its capital expenditure program.

Finance charges were $4.9 million higher than last year, primarily due to the cost of increased borrowings to finance the Company's capital expenditure program and a decrease in the amount of interest capitalized as a result of fewer assets under construction compared to last year.

Corporate taxes decreased $0.6 million from last year, primarily due to the elimination of the Federal Large Corporations' Tax, effective January 1, 2006, partially offset by the impact of increased earnings before corporate income taxes.

Outlook: Customer and electricity sales growth at FortisBC are influenced by general economic growth. Economic growth in British Columbia was strong in 2006 and is expected to continue into 2007 with GDP growth forecast at more than 3.2 per cent. Electricity sales growth at FortisBC is forecasted at approximately 1.6 per cent for 2007.

On September 29, 2006, FortisBC filed its 2007 Preliminary Revenue Requirements Application requesting a 2.9 per cent increase in electricity rates, effective January 1, 2007. The proposed rate increase was primarily driven by FortisBC's ongoing capital expenditure program. Additionally, the rate increase was calculated using the new PBR mechanism described above. On December 19, 2006, an updated 2007 Revenue Requirements Application was filed requesting a 1.2 per cent rate increase which was approved by the BCUC on December 20, 2006. The difference in the revenue requirements between the two filings largely related to increased incentives owing to customers and reduced power purchase costs. On March 9, 2007, the BCUC issued an order requiring FortisBC to increase its customer rates by 2.1 per cent. The increase is the result of a change in the treatment of financing costs related to large capital projects during the period of construction and will become effective in April 2007.

FortisBC's allowed ROE for 2007 has been reduced to 8.77 per cent from 9.20 per cent for 2006 due to the impact of lower long-term Canada bond yields on the automatic adjustment formula used to calculate the allowed ROE.

On November 24, 2006, the BCUC approved FortisBC's 2007 and 2008 Capital Expenditure Plan ("Capital Plan"), filed on July 26, 2006, to spend approximately $135.8 million, before customer contributions of $7.2 million, in 2007 and $119.6 million, before customer contributions of $8.0 million, in 2008. The Capital Plan was approved with six projects totalling $61.2 million subject to further approval processes. The Capital Plan expenditures address the expansion and upgrade of the transmission and distribution systems to keep pace with load growth, while improving customer service, and the continuation of the life-extension program of the Company's hydroelectric generating plants.

Newfoundland Power

Financial Highlights

Years Ended December 31st	**2006**	2005	Variance
Electricity Sales *(GWh)*	**4,995**	5,004	(9)
($ millions)			
Revenue	**421.3**	420.0	1.3
Energy Supply Costs	**257.2**	256.0	1.2
Operating Expenses	**54.0**	53.8	0.2
Amortization	**33.1**	32.1	1.0
Finance Charges	**32.7**	31.4	1.3
Corporate Taxes	**13.6**	15.4	(1.8)
Non-Controlling Interest	**0.6**	0.6	–
Earnings	**30.1**	30.7	(0.6)

Regulation: Newfoundland Power operates under cost of service regulation as administered by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The Company's earnings are regulated on the basis of rate of return on rate base. The determination of the forecast rate of return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which customer rates are determined. An automatic adjustment formula, based on observed long-term Canada bond yields, is utilized annually to determine the permitted rate of return for those years between general rate applications. The formula sets an appropriate ROE which is used to determine the rate of return on rate base.

In January 2006, Newfoundland Power received approval from the PUB of its final 2006 electricity rates. The rates were based on an allowed ROE of 9.24 per cent, which remained unchanged from 2005.

Effective January 1, 2006, the Company changed its revenue recognition policy from the billed basis to the accrual basis, as approved by the PUB on December 23, 2005. The use of the accrual method for revenue recognition better matches revenue and expenses and is consistent with mainstream Canadian utilities' practice. Adoption of the accrual method for revenue recognition gave rise to a $23.6 million balance sheet accrual for unbilled revenue at December 31, 2005 (the "2005 Unbilled Revenue"). Pursuant to an Order by the PUB, Newfoundland Power recorded $3.1 million of the 2005 Unbilled Revenue as revenue in 2006 to offset the income tax impact of changing to the accrual method for revenue recognition. The PUB also ordered that the Company defer recovery of a $5.8 million increase in 2006 capital asset amortization. The deferral establishes a regulatory asset to be recovered in a future period.

Earnings: Newfoundland Power's earnings were $0.6 million lower than last year due to lower electricity sales, lower interest revenue and increased costs associated with purchased power, amortization and finance charges, partially offset by the impact of a lower effective income tax rate. Adoption of the accrual method for revenue recognition did not have a material impact on 2006 annual earnings.

Electricity Sales: Electricity sales were 9 GWh, or 0.2 per cent, lower than last year, primarily due to a decrease in average consumption, partially offset by an increase in the number of customers. Adoption of the accrual method for revenue recognition did not have a material impact on 2006 annual electricity sales.

Revenue: Revenue was $1.3 million higher than last year, primarily due to the recognition of $3.1 million of 2005 Unbilled Revenue, partially offset by lower electricity sales and lower interest revenue. Interest revenue during the second quarter of 2005 included $2.1 million ($1.4 million after-tax) as a result of an income tax settlement with the Canada Revenue Agency ("CRA"). Adoption of the accrual method for revenue recognition did not have a material impact on 2006 annual electricity revenue.

Expenses: Newfoundland Power purchases approximately 90 per cent of its energy requirements from Newfoundland Hydro. Energy supply costs were $1.2 million higher than last year, primarily due to an increase in demand charges under the wholesale demand and energy rate structure. As a result, the unit cost of purchased power increased to 5.289 cents per kilowatt hour ("kWh") compared to 5.261 cents per kWh last year.

Operating expenses were $0.2 million higher than last year. Higher pension and early retirement program costs of approximately $0.9 million were partially offset by lower labour costs resulting from a 2005 early retirement program, a reduction in PUB assessments in 2006 and the reduction of other non-labour costs due to the Company's ongoing focus on initiatives to reduce operating expenses. Pension costs increased primarily due to a reduction in the discount rate used in 2006 to determine annual pension expense.

Amortization costs increased $1.0 million over last year, primarily due to the impact of continued investment in capital assets.

Finance charges were $1.3 million higher than last year due to the replacement in August 2005 of lower-cost revolving credit facility borrowings with 30-year 5.441% first mortgage sinking fund bonds in the amount of $60 million and additional credit facility borrowings used to finance the Company's capital expenditure program.

Corporate taxes were $1.8 million lower than last year, primarily due to the elimination of the Federal Large Corporations' Tax, effective January 1, 2006, increased capital cost allowance rates and the income tax treatment of regulatory amortizations and deferrals.

Outlook: The growth in electricity sales at Newfoundland Power in 2007 is expected to be approximately 1.0 per cent.

In September 2006, the PUB approved Newfoundland Power's $62.2 million 2007 Capital Program, which will focus on the replacement of aging equipment to strengthen the electricity system and the Company's obligation to meet the demands of customer and electricity sales growth. Approximately $18.8 million of the 2007 Capital Program will be spent to refurbish the Company's Rattling Brook hydroelectric generating plant in central Newfoundland.

On December 5, 2006, the PUB approved, as filed on September 13, 2006, Newfoundland Power's 2007 Amortization and Cost Deferral Application (the "2007 Application"). The approved 2007 Application allows for amortization of $2.7 million of the 2005 Unbilled Revenue to offset the 2007 income tax impact of changing to the accrual method for revenue recognition, and the deferred recovery of capital asset amortization of $5.8 million, similar to 2006. The approval also allows for the deferred recovery of $1.1 million related to the cost of replacement energy while the Company's Rattling Brook hydroelectric generating facility is being refurbished. Disposition of the remaining 2005 Unbilled Revenue will be determined by future orders of the PUB.

Newfoundland Power's allowed ROE has been reduced to 8.60 per cent, effective January 1, 2007, due to the impact of lower long-term Canada bond yields on the automatic adjustment formula used to calculate the allowed ROE.

On December 14, 2006, the PUB approved, on an interim basis, an average 0.07 per cent increase in customer electricity rates, effective January 1, 2007. The increase is the result of the flow-through of increased costs from Newfoundland Hydro, which will have no impact on Newfoundland Power's earnings, partially offset by a 0.5 per cent decrease due to the reduction in Newfoundland Power's allowed ROE to 8.60 per cent, effective January 1, 2007. The decrease in the allowed ROE is anticipated to reduce Newfoundland Power's revenue by approximately $2.5 million in 2007.

During 2007, Newfoundland Power expects to file a general rate application with the PUB for the purpose of setting customer rates for 2008.

Maritime Electric

Financial Highlights

Years Ended December 31st	2006	2005	Variance
Electricity Sales *(GWh)*	**999**	989	10
($ millions)			
Revenue	**122.4**	116.7	5.7
Energy Supply Costs	**73.0**	71.6	1.4
Operating Expenses	**12.8**	12.5	0.3
Amortization	**10.1**	9.7	0.4
Finance Charges	**10.3**	7.6	2.7
Corporate Taxes	**6.4**	6.2	0.2
Earnings	**9.8**	9.1	0.7

Regulation: In December 2003, the Government of PEI proclaimed legislation returning Maritime Electric to traditional cost of service regulation. Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island), effective January 1, 2004. Maritime Electric's basic electricity rates are based on estimated cost of service and provide for an approved rate of return on approved rate base assets. The new legislation, which provided for an orderly transition from the previous regulatory model, also allows Maritime Electric to collect the $20.8 million in energy costs recoverable from customers deferred as at December 31, 2003 under terms and conditions set by IRAC. Effective January 1, 2004, as ordered by IRAC, Maritime Electric maintains an energy cost adjustment mechanism ("ECAM") that helps mitigate the impact of fluctuating energy costs on the Company's financial results as it allows Maritime Electric to collect/rebate energy costs above/below a base rate of 6.73 cents per kWh.

On June 27, 2006, IRAC issued its Order with respect to Maritime Electric's general rate application filed on January 31, 2006. The impact was an overall average decrease in customer electricity rates of 1.2 per cent, effective July 1, 2006. The 1.2 per cent decrease was the result of the impact of the refund to customers of energy-related costs associated with the operation of the ECAM, partially offset by a 3.35 per cent increase in basic electricity rates. IRAC approved Maritime Electric's maximum allowed ROE at 10.25 per cent for 2006 and 2007. IRAC also approved continuation of the amortization of the $20.8 million in deferred costs recoverable from customers accumulated as at December 31, 2003 in the amount of $1.5 million in 2006. IRAC ordered the continuation of the ECAM currently in effect, with the amortization period contained in the ECAM to decrease from 18 months to 12 months, effective January 1, 2007.

In November 2006, IRAC approved a new Energy Purchase Agreement ("EPA") with New Brunswick Power ("NB Power") covering the period from November 2006 to March 2008. The cost of energy under the new EPA is subject to the operation of the ECAM.

Earnings: Maritime Electric's earnings were $0.7 million higher than last year, primarily due to the 3.35 per cent increase in basic electricity rates, effective July 1, 2006, and higher electricity sales, partially offset by increased finance charges.

Electricity Sales: Electricity sales were 10 GWh, or 1.0 per cent, higher than last year. The increase was driven by customer growth in the residential sector. Customer energy conservation practices have tempered sales growth during 2006 with average consumption remaining stable year over year.

Revenue: Revenue was $5.7 million higher than last year, primarily as a result of increased electricity sales, the 3.35 per cent increase in basic electricity rates, effective July 1, 2006, and a $1.0 million decrease in the amortization of pre-2004 deferred costs recoverable from customers.

Expenses: Energy supply costs, adjusted for the ECAM, were $1.4 million higher than last year, primarily due to increased electricity sales. Gross energy supply costs, before ECAM adjustments, however, were $4.0 million higher than last year, primarily due to increased electricity sales and higher prices paid for energy under the new EPA with NB Power that came into effect in November 2006. During 2006 and 2005, Maritime Electric purchased the majority of its energy from NB Power under several energy purchase agreements.

Operating expenses were $0.3 million higher than last year, driven by costs associated with an extensive tree trimming program during 2006 and increased insurance and regulatory costs.

Amortization costs were $0.4 million higher than last year. The increase reflected the addition of the 50-MW combustion turbine generating facility and expenditures associated with the Company's ongoing capital program, partially offset by a $0.5 million reduction in the amortization of the deferred charge related to the Point Lepreau Nuclear Generating Station as the expected life of the Station will be extended to 2035 upon its refurbishment by NB Power.

Finance charges were $2.7 million higher than last year, primarily due to financing associated with the Company's capital expenditure program.

Outlook: GDP growth for PEI in 2007 is forecast to be approximately 2.2 per cent. Electricity sales growth at Maritime Electric in 2007 is forecast to be 1.1 per cent, comparable to the growth rate experienced in 2006.

On August 22, 2006, Maritime Electric received approval from IRAC of a 39-MW Wind Power Purchase Agreement (the "Agreement") with PEI Energy Corporation for energy deliveries commencing on or after January 1, 2007. Recent legislation proclaimed by the Government of PEI will require Maritime Electric to obtain at least 15 per cent of its annual energy requirements from renewable sources, such as wind-powered energy, by 2010. The Agreement, in conjunction with the existing wind-energy purchase agreements, will enable the Company to reach this 15 per cent target. Energy from the Agreement is subject to the operation of the ECAM.

In November 2006, the Company filed its 2007 Capital Budget Application ("2007 Capital Budget") for approximately $20.5 million, before customer contributions of $2.7 million. On March 1, 2007, IRAC approved the 2007 Capital Budget at $19.7 million, before customer contributions of $2.7 million.

In December 2006, IRAC approved the amortization of $1.3 million of the deferred costs recoverable from customers accumulated as at December 31, 2003 and increased the amortization to $2.0 million in 2008 and each year thereafter. Deferred costs recoverable from customers totalled $15.3 million at the end of 2006.

Maritime Electric expects to file a rate application with IRAC in the fall of 2007 for the purpose of setting customer rates for 2008.

FortisOntario

Financial Highlights

Years Ended December 31st	**2006**	2005	Variance
Electricity Sales *(GWh)*	**1,163**	1,195	(32)
($ millions)			
Revenue	**130.0**	139.7	(9.7)
Energy Supply Costs	**97.7**	110.2	(12.5)
Operating Expenses	**14.7**	14.5	0.2
Amortization	**5.4**	5.1	0.3
Finance Charges	**5.1**	5.1	–
Corporate Taxes	**3.1**	0.5	2.6
Earnings	**4.0**	4.3	(0.3)

Regulation: FortisOntario includes the regulated operations of Canadian Niagara Power and Cornwall Electric both of which operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost of service regulation and earnings are regulated on rate of return on rate base, plus a recovery of allowable distribution costs. Cornwall Electric is exempt from many aspects of these Acts and is also governed by a 35-year Franchise Agreement with the City of Cornwall, dated July 31, 1998. Rates under the Franchise Agreement are subject to a price cap with commodity cost flow-through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth. In November 2004, the OEB granted Cornwall Electric a Distribution Licence valid until December 2019. The Licence acknowledges the existing service territory and franchise agreements. Prior to this date, Cornwall Electric had been granted an Interim Distribution Licence.

On December 9, 2004, the *Electricity Restructuring Act, 2004* (Ontario) came into force amending certain prior Acts. It reorganized the Province of Ontario's electricity sector and introduced the Regulated Price Plan, which was later developed and announced by the OEB on March 11, 2005. The Regulated Price Plan is intended to reflect the true cost of electricity. It has replaced the interim two-tiered commodity pricing structure that had been in place since April 2004. Effective November 1, 2006, eligible residential customers pay 5.5 cents per kWh for a threshold amount of electricity used each month and 6.4 cents per kWh for electricity consumed over the threshold amount. The threshold is 1,000 kWh per month for November through April and 600 kWh per month for May through October. The threshold for non-residential customers is 750 kWh year-round.

On April 28, 2006, the OEB issued its Decision and Order concerning Canadian Niagara Power's application for new electricity rates, effective May 1, 2006. The Decision and Order also approved the final recovery from customers of regulatory assets including the transitional costs incurred in preparation for the open market in May 2002. The impact of the Decision and Order on a typical residential customer with average monthly consumption of 1,000 kWh in Fort Erie, Port Colborne and Gananoque was an increase in customer rates, effective May 1, 2006, of 17.5 per cent, 17.5 per cent, and 10.8 per cent, respectively. The rate increases also included the impact associated with the flow-through to specified low-volume customers of increased power prices paid to the Independent Electricity System Operator ("IESO") as set under the OEB's Regulated Price Plan. The new distribution electricity rates were based on 2004 costs using a deemed capital structure at 50 per cent long-term debt and 50 per cent common equity, with an allowed ROE of 9.0 per cent. The approved rate increases represented the first time that the Company had been allowed to rebase its rates since 2001.

Earnings: FortisOntario's earnings were $0.3 million lower than last year. Earnings last year included $1.6 million related to the recognition of a future income tax asset associated with the favourable resolution of a CRA reassessment related to Cornwall Electric. Excluding this item, earnings were $1.3 million higher than last year, primarily due to increased distribution electricity rates, effective May 1, 2006, partially offset by increased corporate taxes and reduced electricity sales.

Electricity Sales: Electricity sales were 32 GWh, or 2.7 per cent, lower than last year, primarily due to the impact of moderate weather conditions and the loss of an industrial customer in December 2005.

Revenue: Revenue was $9.7 million lower than last year, primarily due to decreased market energy costs billed to customers and lower electricity sales, partially offset by higher distribution electricity rates, effective May 1, 2006, and increased other revenue. An increase in other revenue of $0.8 million was associated with street lighting maintenance and other miscellaneous customer billings and interest revenue.

Expenses: Energy supply costs were $12.5 million lower than last year, primarily due to lower market energy prices and reduced electricity sales, partially offset by the impact of increased power purchase rates under the OEB's Regulated Price Plan.

Operating expenses were $0.2 million higher than last year. Operating expenses last year included approximately $0.8 million in costs associated with an early retirement program. Operating expenses increased primarily due to higher payroll and benefit costs as a result of the transferring of certain former Rankine Generating Station employees to Canadian Niagara Power, increased internal labour costs associated with repairing damage to a portion of the distribution system caused by an early winter storm that occurred in October 2006 and other miscellaneous cost increases.

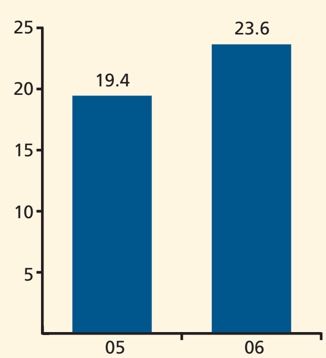
Corporate taxes were $2.6 million higher than last year. Last year, a $1.6 million future income tax asset and corresponding decrease in corporate income taxes were recorded in connection with the favourable resolution of a CRA reassessment of a tax asset created when Cornwall Electric was acquired by a previous owner. Excluding this item, corporate taxes were higher than last year because of higher earnings before corporate taxes and the impact of the reduction of future income tax asset balances during the second quarter of 2006 resulting from enacted future Federal income tax rate reductions.

Outlook: FortisOntario is projecting economic growth of approximately 1.0 per cent in 2007 in the regions it serves. FortisOntario expects to spend approximately $10 million on its 2007 capital program. The 2007 capital program is primarily for continued sustainment of the Company's electricity system.

In December 2006, the OEB issued its final "Report of the Board on Cost of Capital and Second Generation Incentive Regulation for Ontario's Electricity Distributors". The report sets out a three-year price cap plan that maintains the current cost of capital and introduces an inflation measure coupled with a productivity factor for rate-setting purposes. Over that three-year period distributors will be required, in three tranches, to submit a full cost of service application to set new distribution rates. This will be followed by a third-generation incentive mechanism. On January 26, 2007, Canadian Niagara Power filed applications with the OEB requesting a 0.2 per cent average increase in distribution electricity rates, effective May 1, 2007, associated with its operations in Fort Erie, Port Colborne and Gananoque. The rate increase reflects the application of second-generation incentive regulation. Canadian Niagara Power also applied to the OEB to recover in customer rates the extraordinary costs incurred as a result of the early winter storm that occurred in October 2006.

There are approximately 90 municipally owned local distribution companies in Ontario. Management believes further consolidation of municipal electric utilities is likely and FortisOntario will continue to pursue opportunities to lease or acquire local distribution companies as they become available.

Regulated Earnings – Caribbean *($ millions)*



Regulated Utilities – Caribbean

Earnings contributions from Regulated Utilities – Caribbean during 2006 were $23.6 million (2005 – $19.4 million), which represented approximately 17 per cent (2005 – 16 per cent) of the Corporation's total regulated earnings. Regulated Utilities – Caribbean assets were approximately 18 per cent of the Corporation's total regulated assets as at December 31, 2006 (December 31, 2005 – 10 per cent).

Belize Electricity[(1)]

Financial Highlights

Years Ended December 31st	2006	2005	Variance
Average US:CDN Exchange Rate[(2)]	**1.13**	1.21	(0.08)
Electricity Sales *(GWh)*	**360**	350	10
($ millions)			
Revenue	**88.5**	75.8	12.7
Energy Supply Costs	**51.7**	40.8	10.9
Operating Expenses	**10.8**	10.7	0.1
Amortization	**5.4**	5.8	(0.4)
Finance Charges	**3.8**	6.0	(2.2)
Foreign Exchange Loss (Gain)	**0.4**	(0.4)	0.8
Corporate Taxes and Non-Controlling Interest	**6.0**	4.9	1.1
Earnings	**10.4**	8.0	2.4

(1) Fortis holds a 70.1 per cent controlling interest in Belize Electricity.
(2) The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00.

Regulation: Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). Basic electricity rates at Belize Electricity are comprised of two components. The first component is Value-Added Delivery ("VAD") and the second is cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow-through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes, amortization and rate of return on regulated asset base in the range of 10 per cent to 15 per cent. Belize Electricity's regulation includes a Cost of Power Rate Stabilization Account ("CPRSA") designed to normalize changes in the price of electricity due to the fluctuating cost of power. The CPRSA stabilizes electricity rates for consumers while providing Belize Electricity with a mechanism that permits the recovery of its cost of power. Effective July 1, 2002, a Hurricane Cost of Power Rate Stabilization Account ("HCPRSA") was also established to normalize hurricane reconstruction costs. The VAD component of the tariff is normally reviewed every four years, while the COP component and rate stabilization account ("RSA") recovery are reviewed at each annual rate proceeding and at Threshold Event Review Proceedings, which can occur at any time when deferrals of COP into the RSA exceed $1.7 million (BZ$3.0 million). Adjustments to the tariff as a result of a Threshold Event may require adjustments to the COP component of the tariff and additional CPRSA recovery surcharges at any time during a calendar year.

Belize Electricity filed its first full Tariff Application on March 2, 2005 to establish a new four-year VAD tariff setting arrangement. On July 14, 2005, the PUC delivered its Final Tariff Decision approving an overall 11 per cent increase in electricity rates, inclusive of the recovery of RSA balances, to BZ39.0 cents per kWh from BZ34.9 cents per kWh, effective July 1, 2005 through June 30, 2006.

On December 31, 2005, the PUC approved a BZ0.6 cent per kWh, or 1.5 per cent, increase in electricity rates associated with the recovery of excess deferrals to the CPRSA and a BZ4.5 cent per kWh, or 11.5 per cent, increase in electricity rates related to COP. There was no increase in the VAD component of rates. The result was an overall 13 per cent increase in electricity rates to BZ44.1 cents per kWh from BZ39.0 cents per kWh, effective January 1, 2006. This increase in electricity rates was the result of the PUC's Final Decision on Belize Electricity's Threshold Event Review Application filed on December 20, 2005, and had no impact on the Company's earnings due to the flow-through of cost of power to customers.

On May 9, 2006, the PUC issued its Final Decision approving, as filed, Belize Electricity's Annual Tariff Review Application for the annual tariff period from July 1, 2006 to June 30, 2007. The Final Decision confirmed that the average mean electricity rate of BZ44.1 cents per kWh would remain unchanged from that in effect at January 1, 2006. The COP component of rates, however, decreased slightly from BZ25.5 cents per kWh to BZ25.3 cents per kWh, while an Annual Correction Rate, at BZ0.2 cents per kWh, was introduced to collect from customers the differences of actual expenses and revenues from original forecasts for the immediately preceding annual tariff period.

Belize Electricity's Licence to generate, transmit, distribute and supply electricity in Belize expires in 2015. Under the terms of the Licence, the Company has a right of first refusal on any replacement licence. If the current Licence is not renewed for any reason, Belize Electricity will be entitled to receive, upon the transfer of its electric utility assets to a new operator, the greater of market value or 120 per cent of the net book value of these assets.

Earnings: Belize Electricity's earnings were $2.4 million (BZ$5.4 million) higher than last year. Excluding the impact of foreign currency exchange upon the translation of Belize Electricity's results into Canadian dollars, the increase in Belize Electricity's earnings was driven by the overall 11 per cent increase in electricity rates, effective July 1, 2005, as a result of the new four-year tariff agreement, electricity sales growth and lower finance charges, partially offset by the foreign exchange impact associated with the Company's Euro and Canadian dollar-denominated debt and increased operating expenses. The translation of Belize Electricity's results was unfavourably impacted by the weakening of the US dollar against the Canadian dollar compared to last year.

Electricity Sales: Electricity sales were 10 GWh, or 2.9 per cent, higher than last year, driven by growth in sales in the commercial and industrial sectors. The rate of sales growth for 2006 was lower than the rate of sales growth for last year, due to a slowdown in economic growth and customer energy-conservation efforts resulting from the rate increases in July 2005 and January 2006.

Revenue: Revenue was $12.7 million (BZ$30.7 million) higher than last year. Excluding foreign currency translation impacts, revenue increased 24.5 per cent, largely driven by the increase in the VAD and COP components of electricity rates, effective July 1, 2005, the increase in the COP component of electricity rates, effective January 1, 2006, and electricity sales growth.

Expenses: Energy supply costs were $10.9 million (BZ$23.7 million) higher than last year. Excluding foreign currency translation impacts, energy supply costs increased 35.1 per cent, primarily due to increases in the COP component of electricity rates, effective July 1, 2005 and January 1, 2006, and electricity sales growth. On July 1, 2006, the COP component of electricity rates decreased BZ0.2 cents per kWh and did not have a significant impact on energy supply costs year over year. Belize Electricity purchases the majority of its energy requirements from Comisión Federal de Electricidad ("CFE"), the Mexican state-owned power company, and from BECOL.

Operating expenses were $0.1 million (BZ$1.2 million) higher than last year. Excluding foreign currency translation impacts, operating expenses increased primarily due to increased licences and fees, increased line maintenance activities, new customer service and loss reduction initiatives, higher employee costs and general increases in the cost of goods and services.

Excluding foreign currency translation impacts, amortization costs were comparable year over year. The impact of capital asset growth was offset by the recovery of all generation equipment amortization through cost of power, as a result of the July 1, 2005 Final Tariff Decision.

Finance charges were $2.2 million (BZ$3.2 million) lower than last year. The decrease was primarily due to the repayment, with proceeds from a recent share offering, of certain trade payables, inter-company and external loans, and overdraft facilities incurred primarily to finance the CPRSA for the cost of power and fuel. Additionally, during the last half of 2006, excess funds from the share offering were invested on a short-term basis.

In June 2006, Belize Electricity received gross proceeds of approximately $37.2 million (US$33.4 million) upon the closing of a share offering in which approximately 97 per cent of the share purchase rights issued to shareholders were exercised. Under the offering, Belize Electricity issued a right to acquire one Ordinary Share of the Company at par value of BZ$2.00 for every issued and outstanding Ordinary Share. The ownership level in Belize Electricity by Fortis increased from 68.5 per cent to 70.1 per cent as a result of Fortis purchasing all of the Ordinary Shares on which it had rights and acquiring shares under rights purchased from other shareholders. The result was a $26.8 million increase in the Corporation's investment in Ordinary Shares of Belize Electricity. The proceeds from the share offering allow Belize Electricity to continue its capital projects to improve service reliability and meet growing energy demand.

The foreign exchange losses and gains primarily related to foreign currency exchange rate fluctuations associated with Belize Electricity's Euro and Canadian dollar-denominated debt. During 2006, net foreign exchange losses were $0.4 million (BZ$0.6 million) compared to net foreign exchange gains of $0.4 million (BZ$0.6 million) last year. During 2006, the US dollar weakened relative to the Euro and Canadian dollar.

Outlook: The GDP of Belize is estimated to grow between 2.0 per cent and 3.0 per cent in 2007. Belize Electricity anticipates electricity sales growth in 2007 to be approximately 4.7 per cent, compared to 2.9 per cent in 2006.

Belize Electricity expects to spend approximately $28.0 million (BZ$48.0 million) on its 2007 capital program. The 2007 capital program includes approximately $7.0 million (BZ$12.0 million) associated with an upgrade to a gas turbine to increase its capacity by 5.5 MW to 27 MW.

Belize Electricity signed a new Power Purchase Agreement ("PPA") with CFE following the expiration of the previous agreement with CFE on August 20, 2006. The PPA is effective until August 20, 2008 for the provision of up to 15 MW of firm energy and up to a maximum of 40 MW on an economic basis if no firm energy is utilized. Belize Electricity's cost of power under the PPA is based on international fuel prices, which increased the average cost of power from CFE by approximately 59 per cent in 2006. As a result, Belize Electricity has reduced its supply of power from CFE from 25 MW to 15 MW of firm energy. Increased power purchases from BECOL have offset the increased cost of power from CFE and stabilized rates during the latter part of 2006. Any fluctuations in the cost of power above or below the reference cost of power, currently set at BZ25.3 cents per kWh, flows through to customers through the operation of the CPRSA. The balance in the CPRSA declined from BZ$28.2 million at the beginning of 2006 to BZ$18.4 million at the end of 2006.

The Company's continued long-term strategy is to mitigate the risk of fuel price increases to customers by diversifying its sources of energy supply. During 2007, BECOL is expected to commence the construction of a $61 million (US$52.5 million) 18-MW hydroelectric generating facility at a location on the Macal River in Belize called Vaca, pending regulatory approval. BECOL has signed a 50-year power sales agreement with Belize Electricity for the sale of the energy generated by the Vaca facility, commencing in late 2009. The run-of-river Vaca facility is expected to increase annual energy production from the Macal River by approximately 90 GWh to 250 GWh. In 2004, Belize Electricity signed a power purchase agreement with Hydro Maya Limited to purchase output from a 3-MW run-of-river hydroelectric plant in the Punta Gorda District of southern Belize. This facility became operational in February 2007. Additionally, Belize Electricity signed a power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen") in December 2004 for the supply of approximately 14 MW of power. This facility is scheduled to become operational in mid-2009.

Caribbean Utilities

Financial Highlights

Years Ended December 31st	2006	2005	Variance
Average US:CDN Exchange Rate[1]	**1.14**	1.22	(0.08)
Electricity Sales *(GWh)*[2]	**485**	402	83
($ millions)			
Equity Income	**9.7**	11.4	(1.7)

(1) The Cayman Island dollar is pegged to the US dollar at CI$0.84 = US$1.00.

(2) As reported by Caribbean Utilities for the twelve-month periods ended October 31, 2006 and October 31, 2005.

During 2006 and 2005, Fortis accounted for its previous approximate 37 per cent ownership interest in Caribbean Utilities on an equity basis. Equity income was recorded on a two-month lag and, as a result, the equity income noted above represented the Corporation's share of Caribbean Utilities' earnings for the twelve-month periods ended October 31, 2006 and October 31, 2005. On November 7, 2006, Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities for $55.7 million (US$49.0 million), including acquisition costs, and now owns approximately 54 per cent of the Company. Caribbean Utilities' balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis will consolidate Caribbean Utilities' financial statements on a two-month lag basis.

Regulation: Caribbean Utilities operates the only electric utility on Grand Cayman, Cayman Islands pursuant to a 25-year exclusive Licence, expiring in 2011. The Licence allows for the annual adjustment of tariffs to provide the Company with a rate of return of 15 per cent on capital employed, as defined in the Licence. The 15 per cent rate of return is for the fixed term of the Licence and does not take into consideration actual interest charges, unless they are in excess of 15 per cent per annum, and costs of capital incurred by Caribbean Utilities. The Licence provides for monthly adjustments to be made to electricity rates to reflect variations in the cost of diesel fuel used in the generation of electricity.

Caribbean Utilities submitted a proposal to the Cayman Islands Government (the "Government") in July 2002 to extend its current Licence and replace the 15 per cent rate of return on capital employed mechanism for adjusting customer rates with a price cap mechanism. The resulting non-binding tentative agreement signed by Caribbean Utilities and the Government in June 2004 expired following Hurricane Ivan in September 2004. The current Licence is still in effect and is scheduled to expire in January 2011 or until replaced with a new licence by mutual agreement. The Company resumed Licence renewal discussions with the Government in November 2005.

In 2005, Caribbean Utilities and the Government agreed on a Cost Recovery Surcharge ("CRS") of US0.89 cents per kWh for each kWh of electricity consumed by customers to recover US$13.4 million of direct uninsured Hurricane Ivan losses incurred in 2004. Hurricane Ivan was a Category V hurricane that struck the Cayman Islands in September 2004. The CRS came into effect on August 1, 2005 and will continue for a period of approximately three years. As of October 31, 2006, approximately US$8.0 million of direct uninsured Hurricane Ivan losses remained to be collected from customers through the CRS. It has also been agreed with the Government that there will be no increases in basic billing rates until July 31, 2008 and no retroactive increases in billing rates are permitted after the CRS has been fully recovered. Under its current Licence, Caribbean Utilities was entitled to a 2.0 per cent basic electricity rate increase, effective August 1, 2006, primarily as a result of increased operating expenses and investment in fixed assets. Caribbean Utilities did not implement this basic electricity rate increase, due to the freeze in basic rates during the period of the CRS.

Equity Income: Equity income from Caribbean Utilities during 2006 was $1.7 million lower than last year. Excluding the $1.1 million positive adjustment to equity income last year related to a change in Caribbean Utilities' accounting practice for recognizing unbilled revenue, equity income from Caribbean Utilities decreased $0.6 million due to foreign currency translation impacts associated with the weakening of the US dollar against the Canadian dollar compared to the same period last year. The impact of strong electricity sales growth, revenue associated with the CRS and lower maintenance costs was offset largely by higher insurance premiums, amortization costs and finance charges. During the twelve-month period ended October 31, 2006, electricity sales at Caribbean Utilities were 485 GWh, approximately 21 per cent higher than electricity sales of 402 GWh reported in the same period last year, due to strong residential and commercial sales growth post Hurricane Ivan. Business interruption insurance revenue during the twelve-month period ended October 31, 2006 was US$10 million lower than the same period last year, due to the final impact of business interruption insurance loss claims being recorded during the fourth quarter ended April 30, 2006. Revenue associated with the CRS was US$3.3 million higher period over period due to the CRS becoming effective August 1, 2005.

In May 2006, Caribbean Utilities entered into a project agreement with its strategic alliance partner, MAN B&W Diesel AG of Germany, for the purchase of a 16-MW diesel generating unit and auxiliary equipment to be installed to meet the summer 2007 energy demand for a total project cost of approximately US$22.2 million. As at October 31, 2006, approximately US$5.7 million had been spent by Caribbean Utilities on this project.

Outlook: The Cayman Islands' economy continues to show strong growth in the tourism and financial services sectors which, together with the construction industry, are the pillars of the Cayman Islands' economy and drive Caribbean Utilities' electricity sales growth. Tourist arrivals increased 11 per cent during the nine months ended September 30, 2006 compared to the same period last year. The Cayman Islands is considered one of the leading jurisdictions in the hedge fund industry with more than 8,000 registered hedge funds as of September 2006. A 20 per cent growth in new companies registered in the Cayman Islands was reported in 2006. Construction is robust, with major projects in progress in the tourism, general commercial and residential sectors. Government and the private sector are adding much-needed infrastructure, while supporting a growing economy, through the development of roads, schools, shopping centres, restaurants, commercial buildings and warehouses, hotels and condominiums.

Caribbean Utilities expects electricity sales growth for its 2006/2007 fiscal year to be between 9 per cent and 10 per cent and expects to invest approximately $221.4 million (US$190.0 million) in its capital program over the next five years primarily in support of sales growth.

Fortis Turks and Caicos [(1)]

Financial Highlights

Period Ended December 31st	2006
Average US:CDN Exchange Rate	**1.13**
Electricity Sales *(GWh)*	**44**
($ millions)	
Revenue	**12.6**
Energy Supply Costs	**5.1**
Operating Expenses	**2.0**
Amortization	**1.4**
Finance Charges	**0.6**
Earnings	**3.5**

(1) Financial data is from the date of acquisition on August 28, 2006.

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all issued and outstanding shares of Fortis Turks and Caicos for aggregate consideration of approximately $97.7 million (US$87.8 million). The purchase price, net of assumed debt and acquisition costs, was $75.6 million (US$68.0 million). The acquisition was initially financed through borrowings under the Corporation's credit facilities. A portion of such borrowings was repaid with partial proceeds of a preference share offering that was completed by the Corporation on September 28, 2006. The acquisition was immediately accretive to earnings.

Regulation: Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity customers, in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037. Fortis Turks and Caicos is regulated under a traditional rate of return on rate base approach, with a fixed rate of return of 17.5 per cent on a defined asset base.

Earnings: Earnings from Fortis Turks and Caicos were $3.5 million (US$3.0 million) for the four-month period ended December 31, 2006. Earnings from Fortis Turks and Caicos are being favourably impacted by economic growth throughout the utility's service territories.

Electricity Sales: Electricity sales were 44 GWh during the four-month period ended December 31, 2006, up approximately 26 per cent, or 9 GWh, from electricity sales of 35 GWh during the same period last year. Most of the growth in electricity sales was due to new construction taking place primarily on the island of Providenciales.

Outlook: Electricity sales growth at Fortis Turks and Caicos is expected to average in excess of 15 per cent annually over the next five years with investment in capital assets expected to average approximately US$15 million annually over the same time period.

Non-Regulated

Non-Regulated – Fortis Generation

Fortis Generation consists of the Corporation's investment in non-regulated generation assets. The following table provides a summary of the Corporation's non-regulated generation assets by location.

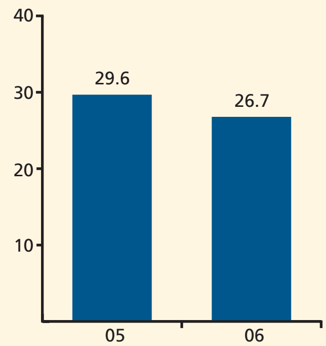
	Plants	Capacity *(MW)*
Belize	2	32
Ontario	8	88
Central Newfoundland	2	36
British Columbia	1	16
Upper New York State	4	23
Total	**17**	**195**

Financial Highlights

Years Ended December 31st	**2006**	2005	Variance
Energy Sales *(GWh)*			
Belize	**178**	68	110
Ontario	**722**	708	14
Central Newfoundland	**168**	159	9
British Columbia	**30**	39	(9)
Upper New York State	**105**	75	30
Total	**1,203**	1,049	154
($ millions)			
Revenue	**79.4**	84.0	(4.6)
Energy Supply Costs	**6.2**	6.2	–
Operating Expenses	**15.2**	17.8	(2.6)
Amortization	**10.5**	10.4	0.1
Finance Charges	**10.0**	14.0	(4.0)
Gain on Settlement of Contractual Matters	**–**	(10.0)	10.0
Corporate Taxes	**8.1**	13.8	(5.7)
Non-Controlling Interest	**2.7**	2.2	0.5
Earnings	**26.7**	29.6	(2.9)

Earnings: Earnings from Non-Regulated – Fortis Generation were $2.9 million lower than last year. Earnings last year included the $10.0 million ($7.9 million after-tax) Ontario Settlement gain. Excluding the impact of the Ontario Settlement gain, earnings were $5.0 million higher than last year. The increase was primarily due to higher production and decreased finance charges largely in Belize, lower operating expenses and lower effective corporate income taxes, partially offset by the impact of lower average wholesale energy prices in Ontario.

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



Energy Sales: Energy sales were 154 GWh, or 14.7 per cent, higher than last year, largely driven by higher hydroelectric production in Belize and Upper New York State. The increase in production in Belize was due to the first full year of operations of the Chalillo storage facility and higher rainfall levels, with production in 2006 more than two-and-a-half times that experienced in 2005. Production in Upper New York State increased primarily due to nearly nine months of operations of the Dolgeville plant in 2006 compared to almost four months last year, and higher production at the Moose River plant. In late January 2005, the Dolgeville plant went out of service as a result of flooding and did not resume production until October 2005. In late June 2006, the Dolgeville plant experienced a disruption in water supply due to flooding and resumed production late in the third quarter of 2006.

Revenue: Revenue was $4.6 million lower than last year, driven by lower average wholesale energy prices in Ontario, partially offset by increased production largely in Belize and the receipt of $1.2 million in insurance proceeds. The average annual wholesale energy price per megawatt hour ("MWh") in Ontario during 2006 was $46.38 compared to $68.49 last year, resulting in a decrease in revenue of approximately $14.2 million. The insurance proceeds related to the Dolgeville plant in Upper New York State as a result of the 2005 flood and represented the final amounts received related to property damage and business interruption loss insurance claims.

Expenses: Operating expenses were $2.6 million lower than last year; however, operating expenses last year included a $1.7 million write-down of assets associated with the lay-up of the Rankine Generating Station and $0.5 million and $0.3 million of costs related to an early retirement program and business development activities, respectively, in Ontario, partially offset by a $0.8 million insurance gain related to the involuntary disposition of assets associated with the 2005 Dolgeville flood. Additionally, operating expenses in 2006 were favourably impacted by cost savings of approximately $1.0 million associated with the cessation of operations at the Rankine Generating Station upon implementation of the Niagara Exchange Agreement in late 2005.

Finance charges were $4.0 million lower than last year, primarily due to the reduction of inter-company finance charges in the Belizean operations and the early repayment of a $22.5 million term loan in the second quarter of 2005 associated with the Ontario operations.

Corporate taxes were $5.7 million lower than last year, primarily due to lower earnings before corporate taxes at the taxable jurisdictions and an increase in the proportion of tax-exempt Belizean earnings.

Outlook: Fortis expects to pursue opportunities associated with non-regulated hydroelectric operations in 2007, including commencement of the construction of the 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize, pending regulatory approval, as well as continuing to develop and enhance existing operations.

Non-Regulated – Fortis Properties

Fortis Properties consists of the Corporation's investment in non-regulated commercial real estate and hotel assets.

Financial Highlights

Years Ended December 31st

($ millions)	**2006**	2005	Variance
Real Estate Revenue	**54.8**	52.9	1.9
Hospitality Revenue	**108.1**	101.5	6.6
Total Revenue	**162.9**	154.4	8.5
Operating Expenses	**105.3**	100.0	5.3
Amortization	**12.4**	11.2	1.2
Finance Charges	**21.0**	20.0	1.0
Gain on Sale of Income Producing Property	**(2.1)**	–	(2.1)
Corporate Taxes	**7.6**	9.1	(1.5)
Earnings	**18.7**	14.1	4.6

Earnings: Fortis Properties' earnings were $4.6 million higher than last year, primarily due to a $2.1 million ($1.6 million after-tax) gain on the sale of Days Inn Sydney during the second quarter of 2006, lower corporate income taxes, growth in the Company's hotel operations in Western Canada driven by the Greenwood Inns and contributions from the operations of several expanded properties. The increase was partially offset by higher amortization costs and finance charges.

On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia from Lodge Motel (Kelowna) Ltd. for an aggregate purchase price of approximately $52.0 million, including assumed debt. The four acquired hotels were the Holiday Inn Express and Suites, and Best Western in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia. This acquisition increased the hospitality operations of Fortis Properties by 454 rooms.

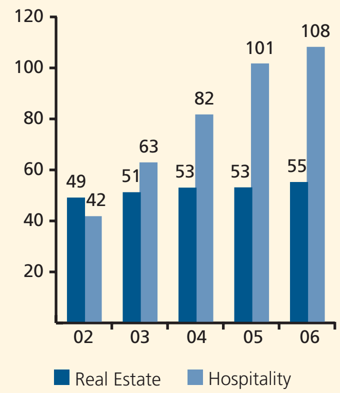
During the second quarter of 2006, Fortis Properties completed the expansion of the Holiday Inn Sarnia with a new five-storey 70-room tower and an additional 3,000 square feet of banquet space, and the 11,000-square foot expansion of the conference facilities at the Holiday Inn Kitchener-Waterloo. The 57,000-square foot expansion of the Blue Cross Centre in Moncton was completed during the third quarter of 2006. Total capital expenditures related to these projects were approximately $16.3 million, with approximately $9.3 million spent in 2006.

Revenue: Real Estate Division revenue was $1.9 million higher than last year, due to the leasing of the Blue Cross Centre expansion and growth experienced in most of the Company's operating regions.

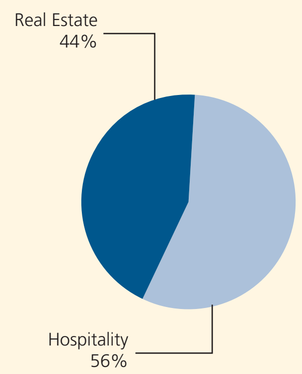
The occupancy rate in the Real Estate Division was 94.9 per cent as at December 31, 2006, down from 95.9 per cent as at December 31, 2005. The decrease in occupancy was primarily attributable to vacancies at rural Newfoundland mall properties and recent lease expiries at the Brunswick Square property in New Brunswick.

Hospitality Division revenue was $6.6 million higher than last year, driven by growth experienced in the Company's hotel operations in Western Canada, the first full year of operations of the expanded Delta St. John's Hotel and the impact of the expanded Ontario hotels, partially offset by the elimination of revenue following the sale of Days Inn Sydney. Revenue per available room ("REVPAR") for 2006 was $72.67 compared to $70.95 for 2005. The 2.4 per cent increase in REVPAR was due to increases in both average occupancy and average room rates.

Fortis Properties
Revenue *($ millions)*



Fortis Properties
2006 Asset Mix



Expenses: Operating expenses were $5.3 million higher than last year, driven primarily by the Company's hotel operations in Western Canada and the impact of the expanded hotel properties. The increase was partially offset by the elimination of operating expenses following the sale of Days Inn Sydney.

Amortization costs were $1.2 million higher than last year, primarily due to the Company's capital program, including property expansions, and acquisition of hotels.

Finance charges were $1.0 million higher than last year, primarily due to financing associated with the four recently acquired hotels and property expansions.

Corporate taxes were $1.5 million lower than last year, largely due to the reduction of future income tax liability balances resulting from enacted future Federal income tax rate reductions and the elimination of the Federal Large Corporations' Tax, effective January 1, 2006.

Outlook: The revenue and earnings impacts from the four recently acquired hotels in Western Canada and the Blue Cross Centre expansion are expected to provide the primary sources of growth at Fortis Properties in 2007.

The Real Estate Division operates in three provinces in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure. There is a continued focus in this Division of a strategy of early tenant renewals.

The Hospitality Division currently operates in seven Canadian provinces. The hospitality industry is impacted by economic factors such as fluctuating energy costs and increasing municipal taxes. Increased supply of hotel rooms in many of the markets in which the Hospitality Division operates has created competitive challenges in recent years and will continue to do so in 2007. The Hospitality Division operates in the mid-to-upper market which targets a large customer base, allowing the Company to reduce exposure to risk associated with a specific market segment. The acquisitions of properties in Western Canada over the last two years have strengthened the Company's geographic diversification.

Corporate

Financial Highlights

Years Ended December 31st

($ millions)	**2006**	2005	Variance
Total Revenue	**9.0**	10.0	(1.0)
Operating Expenses	**10.6**	9.5	1.1
Amortization	**3.0**	2.9	0.1
Finance Charges(1)	**40.5**	38.9	1.6
Foreign Exchange Gain	**(2.1)**	(2.0)	(0.1)
Corporate Tax Recovery	**(9.9)**	(8.3)	(1.6)
Non-Controlling Interest	**(0.2)**	(0.2)	–
Preference Share Dividends	**1.6**	–	1.6
Net Corporate Expenses	**(34.5)**	(30.8)	(3.7)

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

The Corporate segment captures expense and revenue items not specifically related to any operating segment. Included in the Corporate segment are finance charges, including interest on debt incurred directly by Fortis and dividends on preference shares classified as long-term liabilities, foreign exchange gains or losses, dividends on preference shares classified as equity, other corporate expenses net of recoveries from subsidiaries, interest and miscellaneous revenues, and corporate income taxes.

Net corporate expenses were $3.7 million higher than last year, primarily due to increased finance charges, higher preference share dividends associated with the issue of the First Preference Shares, Series F, higher operating expenses and lower inter-company interest revenue. Finance charges were higher than last year due to increased drawings on corporate credit facilities and interest on US$40 million of unsecured subordinated convertible debentures issued in November 2006, partially offset by lower interest costs of $0.8 million on US dollar-denominated debt as a result of the weakening of the US dollar against the Canadian dollar during 2006. Operating expenses last year included $1.8 million of charges resulting from restructuring and related costs associated with the Western Canadian electric utilities which had not been provided for in the acquisition purchase price. The increase in operating expenses was driven by business development costs of $1.7 million incurred in 2006 and an increase in pension and compensation expenses of $1.8 million, partially offset by miscellaneous credits recorded during 2006 that reduced operating expenses by approximately $0.6 million. Pension expense increased largely due to pension plan changes and a decrease in the assumed discount rate used to calculate pension expense. Compensation expense increased due to the impact of the appreciation of the Corporation's Common Shares on the measurement and expensing of Restricted Share Units ("RSU") and Directors' Deferred Share Units ("DSU") issued under the Corporation's RSU Plan and Directors' DSU Plan.

On September 28, 2006, Fortis issued 5,000,000 4.90% First Preference Shares, Series F for gross proceeds of $125 million, or approximately $122.5 million net of after-tax expenses. The net proceeds were largely used to partially fund the recent acquisition of Fortis Turks and Caicos and to fund equity injections into FortisAlberta and FortisBC in support of their extensive capital expenditure programs. The First Preference Shares, Series F are classified as equity on the balance sheet as they are not redeemable at the option of the shareholder. The Corporation's previously issued First Preference Shares, Series C and First Preference Shares, Series E are redeemable at the option of the shareholder and are therefore classified as long-term liabilities on the balance sheet.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2006 and December 31, 2005.

($ millions)	Increase (Decrease)	Explanation
Accounts receivable	73.9	The increase primarily related to accounts receivable of $21.3 million at Caribbean Utilities and $10.3 million at Fortis Turks and Caicos, higher transmission revenue accruals at FortisAlberta as a result of costs previously paid by generators now being paid by load customers and higher accounts receivable balances at most of the regulated utilities due to higher revenues.
Materials and supplies	14.1	The increase primarily related to materials and supplies of $6.1 million at Caribbean Utilities and $5.0 million at Fortis Turks and Caicos.
Deferred charges and other assets	26.7	The increase primarily related to the undepreciated balance of contributions made by FortisAlberta to the AESO for investment in transmission facilities, pension funding in excess of pension expense at Newfoundland Power, an investment at Fortis Properties required as collateral for debt associated with Days Inn Sydney and $1.9 million of deferred charges and other assets at Caribbean Utilities. The increase was partially offset by amortization during 2006.
Regulatory assets – long-term	50.7	The increase primarily related to an increase in AESO charges deferrals at FortisAlberta, the deferred recovery of utility capital asset amortization at Newfoundland Power and an increase in regulatory assets associated with other post-employment benefits at Newfoundland Power, FortisAlberta and FortisBC, combined with $13.7 million of regulatory assets at Caribbean Utilities. The increase was partially offset by a $6.1 million reduction in the CPRSA at Belize Electricity.
Future income tax asset – long-term	(51.8)	The decrease primarily related to the conversion to the taxes payable method of accounting for federal income taxes from the tax liability method for regulatory purposes at FortisAlberta. As a result, the future income tax asset and the corresponding offsetting regulatory liability at FortisAlberta were each reduced by approximately $50.7 million during the second quarter of 2006.
Utility capital assets	674.5	The increase primarily related to $483.1 million invested in electricity systems, $45.8 million of utility capital assets acquired upon the acquisition of Fortis Turks and Caicos and $318.6 million of utility assets acquired upon the acquisition of a controlling interest in Caribbean Utilities. The increase was partially offset by customer contributions and amortization for 2006.
Income producing properties	54.4	On November 1, 2006, Fortis Properties acquired four hotels in Alberta and British Columbia for an aggregate purchase price of approximately $52 million. The remainder of the increase related to the expansions of Holiday Inn Sarnia, Holiday Inn Kitchener-Waterloo and the Blue Cross Centre, partially offset by the sale of Days Inn Sydney and amortization.
Investments	(164.9)	The decrease related to the Corporation's investment in Caribbean Utilities which, upon acquiring a controlling interest in November 2006, has been consolidated in the financial statements of the Corporation. Previously, the Corporation's investment in Caribbean Utilities was accounted for on the equity basis.
Goodwill	149.2	The increase related to US$34.8 million of goodwill recorded upon the acquisition of Fortis Turks and Caicos in August 2006, US$93.2 million of goodwill recorded upon the acquisition of a controlling interest in Caribbean Utilities in November 2006 and the impact of foreign exchange on the translation of the US dollar-denominated goodwill amounts.
Short-term borrowings	48.8	The increase related to short-term borrowings at Maritime Electric, FortisBC and FortisAlberta, primarily to fund utility capital expenditures and operating activities, and to fund Maritime Electric's $5.9 million corporate income tax deposit. The increase also related to short-term borrowings of $9.3 million at Caribbean Utilities. The increase was partially offset by repayment of short-term borrowings at Belize Electricity, Fortis Generation and the Corporation.
Accounts payable and accrued charges	68.5	The increase primarily related to accounts payable and accrued charges of $29.5 million at Caribbean Utilities and $6.6 million at Fortis Turks and Caicos. The increase also related to higher accounts payable and accrued charges at FortisAlberta as a result of the Company's capital expenditure program and costs previously paid by generators now being paid by load customers, and the impact of higher purchased power costs at Newfoundland Power.
Income taxes payable	(22.8)	The decrease primarily related to the payment of income taxes at FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric during 2006.
Deferred credits	14.7	The increase primarily related to the accrual of post-employment benefits at Newfoundland Power, FortisBC and the Corporation, combined with customer deposits associated with Fortis Turks and Caicos.
Regulatory liabilities – long-term	(28.8)	The decrease related to the conversion to the taxes payable method of accounting for federal income taxes from the tax liability method for regulatory purposes at FortisAlberta. As a result, the future income tax asset and the corresponding offsetting regulatory liability at FortisAlberta were each reduced by approximately $50.7 million during the second quarter of 2006. The decrease was partially offset by an increase in the future removal and site restoration provision at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric.

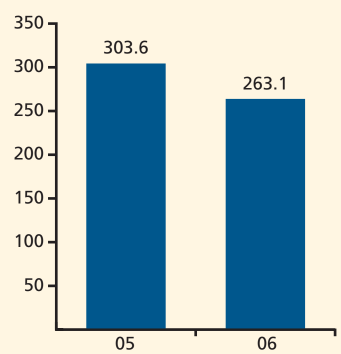
($ millions)	Increase (Decrease)	Explanation
Future income tax liability – long-term	13.0	The increase primarily related to a taxable temporary difference related to the AESO charges deferrals at FortisAlberta.
Long-term debt and capital lease obligations (including current portion)	476.2	The increase related to long-term debt of $173.4 million at Caribbean Utilities and $23.1 million at Fortis Turks and Caicos, combined with increased net drawings on long-term credit facilities of $66.1 million, $39.2 million, $23.4 million and $21.0 million by the Corporation, FortisAlberta, Newfoundland Power and FortisBC, respectively. The increase also related to $100 million of unsecured public debentures issued by FortisAlberta on April 21, 2006, US$40 million of unsecured subordinated convertible debentures issued by the Corporation on November 7, 2006, $11.6 million in long-term debt assumed by Fortis Properties upon the acquisition of the four hotels on November 1, 2006 and approximately $8.5 million in new long-term debt at Belize Electricity. The increase was partially offset by regular debt repayments during the year.
Non-controlling interest	90.9	The increase primarily related to the 46 per cent non-controlling interest in Caribbean Utilities recognized upon consolidation of the financial results of Caribbean Utilities upon Fortis acquiring controlling interest in the Company in November 2006, combined with the non-controlling proceeds related to Belize Electricity's share offering in June 2006.
Shareholders' equity	184.7	The increase primarily related to the $125 million preference share issue, $122.5 million net of after-tax expenses, combined with net earnings reported for 2006, less common share dividends. The remainder of the increase primarily related to the issuance of Common Shares under the Corporation's share purchase, dividend reinvestment and stock option plans, combined with an increase in the equity portion of convertible debentures associated with the Corporation's US$40 million of unsecured subordinated convertible debentures issued on November 7, 2006. The increase was partially offset by a foreign currency translation adjustment of $39.3 million upon consolidation of the previously reported equity investment in Caribbean Utilities.

Liquidity

The following table outlines the summary of cash flows.

Years Ended December 31st ($ millions)	2006	2005	Variance
Cash, beginning of year	**33.4**	37.2	(3.8)
Cash provided by (used in)			
Operating activities	**263.1**	303.6	(40.5)
Investing activities	**(634.1)**	(467.1)	(167.0)
Financing activities	**378.4**	159.9	218.5
Foreign currency impact on cash balances	**0.1**	(0.2)	0.3
Cash, end of year	**40.9**	33.4	7.5

Cash Flow from Operations
($ millions)



Operating Activities: Cash flow from operations, after working capital adjustments, was $40.5 million lower than last year. Cash flow from operations, after working capital adjustments, during 2005 included the $10.0 million Ontario Settlement gain and a corporate income tax refund and related interest at Newfoundland Power of approximately $9.0 million. The decrease in cash flow from operations, after working capital adjustments, was primarily due to: (i) timing differences between when transmission costs were paid and when transmission revenues were collected at FortisAlberta; (ii) higher cash taxes paid at FortisAlberta related to the previous taxation year; (iii) the payment of a $5.9 million corporate income tax deposit at Maritime Electric; (iv) the impact of lower average wholesale energy prices in Ontario; and (v) the timing of amounts due from customers, income taxes payable and accounts payable at Maritime Electric and FortisOntario. The decrease was partially offset by the recovery of higher amortization expense through electricity rates at FortisBC, the impact of increased electricity rates at Belize Electricity, higher earnings at BECOL due to the operation of the Chalillo storage facility and improved hydrology, and earnings contribution from Fortis Turks and Caicos.

Investing Activities: Cash used in investing activities was $167.0 million higher than last year. The increase was primarily due to the acquisition of Fortis Turks and Caicos in August 2006 for a net purchase price of $75.6 million, the acquisition of an additional 16 per cent ownership interest in Caribbean Utilities in November 2006 for a net purchase price of $53.0 million, the purchase of four hotels in Alberta and British Columbia in November 2006 for a net purchase price of $40.4 million, increased electric utility capital expenditures and increased deferred charges at FortisAlberta related to payments made to the AESO associated with transmission capital projects. The increase was partially offset by lower capital expenditures associated with income producing properties, increased contributions in aid of construction and proceeds from the sale of Days Inn Sydney in June 2006.

Gross electric utility capital expenditures were $483.1 million, $58.3 million higher than last year. The increase in gross electric utility capital expenditures primarily related to capital spending at FortisAlberta, largely driven by customer growth, rising material and labour costs, capacity increases, system improvements and substation upgrades. The increase was partially offset by decreased utility capital expenditures at Maritime Electric and BECOL due to the substantial completion during 2005 of the construction of the 50-MW combustion turbine generating facility on PEI and the Chalillo Project in Belize, respectively.

Capital expenditures associated with income producing properties were $4.4 million lower than last year. During 2006 and 2005, capital expenditures associated with income producing properties included expenditures related to the expansions of Holiday Inn Sarnia, Holiday Inn Kitchener-Waterloo and the Blue Cross Centre in Moncton, which were completed in 2006. Capital expenditures associated with income producing properties during 2005 also included expenditures related to the completion of the expansion of the Delta St. John's Hotel.

Contributions received in aid of construction were $8.4 million higher than last year, primarily due to increased contributions associated with FortisAlberta's capital expenditure program.

Financing Activities: Cash provided from financing activities was $378.4 million, $218.5 million higher than last year.

In September 2006, the Corporation issued preference shares for net proceeds of approximately $121.1 million. A portion of the proceeds were used to repay certain indebtedness under Corporate long-term credit facilities as outlined below. In March 2005, the Corporation issued 6.9 million Common Shares for net proceeds of approximately $123.9 million which was used, in part, to repay short-term indebtedness associated with the acquisition of FortisAlberta and FortisBC in 2004.

During 2006, the Corporation issued, by way of private placement, US$40 million of unsecured subordinated convertible debentures to fund, in part, the acquisition in November 2006 of an additional 16 per cent ownership interest in Caribbean Utilities. Additionally, the Corporation drew approximately $135.3 million under long-term credit facilities to finance, on an interim basis, the acquisition of Fortis Turks and Caicos; to finance, in part, the acquisition by Fortis Properties of four hotels in Alberta and British Columbia in November 2006 and the acquisition of an additional 16 per cent ownership interest in Caribbean Utilities in November 2006; to fund an equity injection into one of the Corporation's Western Canadian utilities; and for general corporate purposes. Additionally, FortisAlberta issued $100 million in unsecured debentures in April 2006. The net proceeds of the debenture offering were used primarily to repay existing indebtedness on FortisAlberta's long-term credit facility. Belize Electricity also issued approximately $8.5 million in debentures during 2006. During 2006, an aggregate of $176.3 million was drawn under long-term credit facilities at FortisAlberta, FortisBC and Newfoundland Power, primarily to fund their respective capital expenditure programs. During 2005, proceeds from long-term debt primarily related to the issue by FortisBC of 30-year 5.6% $100 million senior unsecured debentures, the proceeds of which were primarily used to repay borrowings under FortisBC's long-term credit facilities; a $60 million bond issue at Newfoundland Power; a $41.9 million financing related to the acquisition of the Greenwood Inns; and approximately $126.8 million of drawings under long-term credit facilities at FortisAlberta and FortisBC, primarily to fund their respective capital expenditure programs. The Corporation also drew $18.0 million under long-term credit facilities during 2005, primarily to fund equity injections into subsidiaries.

During 2006, significant repayments of long-term debt and capital lease obligations primarily related to the repayment by the Corporation, with partial proceeds from the preference share offering, of approximately $71.5 million of indebtedness under long-term credit facilities, and the repayment by FortisAlberta of approximately $97.1 million of indebtedness under a long-term credit facility primarily with proceeds from the $100 million unsecured debenture issue. During 2005, long-term debt and capital lease repayments included the early repayment by FortisOntario of a $22.5 million term loan in May 2005.

During 2006, the Corporation also received approximately $10.6 million in proceeds from non-controlling shareholders related to Belize Electricity's share offering in June 2006.

The remaining financing activities during 2006 and 2005 largely related to dividend payments, normal course issues of common shares through the Corporation's share purchase and stock option plans, regularly scheduled long-term debt repayments and normal course changes in short-term borrowings.

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2006, are outlined in the following table.

($ millions)	**Total**	≤ 1 year	>1–3 years	4–5 years	> 5 years
Long-term debt	**2,614.1**	83.6	205.6	392.8	1,932.1
Brilliant Terminal Station ("BTS")(1)	**68.2**	2.6	5.1	5.1	55.4
Power purchase obligations					
FortisBC(2)	**2,884.6**	38.6	74.1	76.0	2,695.9
FortisOntario(3)	**310.7**	21.9	42.7	44.5	201.6
Maritime Electric(4)	**38.7**	30.1	8.6	–	–
Belize Electricity(5)	**20.2**	2.7	3.4	2.3	11.8
Capital cost(6)	**426.5**	15.7	27.9	35.4	347.5
Joint-use asset and shared service agreements(7)	**64.5**	3.8	7.7	6.7	46.3
Office lease – FortisBC(8)	**21.7**	1.1	2.6	2.4	15.6
Caribbean Utilities(9)	**19.2**	7.7	11.5	–	–
Operating lease obligations(10)	**18.0**	4.5	7.6	5.2	0.7
Other	**4.2**	1.4	1.6	0.1	1.1
Total	**6,490.6**	213.7	398.4	570.5	5,308.0

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

(2) Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric plant located near Castlegar, British Columbia. The BPPA requires monthly payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(3) Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing, which expires June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at $0.14 million per month.

(4) Maritime Electric has one take-or-pay contract for the purchase of either capacity or energy. This contract totals approximately $38.7 million through March 31, 2008.

(5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity, which commenced in February 2007, and a two-year power purchase agreement between Belize Electricity and CFE of Mexico, expiring August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belcogen that provides for the supply of approximately 14 MW of capacity, which is scheduled to commence in mid-2009. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(7) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2011 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

(8) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term. On December 1, 2004, FortisBC also entered into a five-year lease for the Kelowna, British Columbia head office. The terms of the lease allow for termination without penalty after three years.

(9) During 2006, Caribbean Utilities entered into a project agreement for the purchase and turnkey installation of one 16-MW medium-speed diesel generating unit and auxiliary equipment. This unit is scheduled for installation to meet the summer 2007 energy demand. The contract cost is US$18.4 million and the total estimated cost for completion of the project is US$22.2 million. As at October 31, 2006, approximately US$5.7 million had been spent by Caribbean Utilities on this project.

(10) Operating lease obligations include certain office, vehicle and equipment leases and the lease of electricity distribution assets of Port Colborne Hydro Inc.

Capital Resources

The Corporation's principal business of regulated electric utilities requires Fortis to have ongoing access to capital to allow it to build and maintain its electricity systems. In order to ensure access to capital is maintained, the Corporation targets a long-term capital structure that includes a minimum of 40 per cent equity and 60 per cent debt as well as investment-grade credit ratings. The Corporation targets the equity component of its capital structure to consist of at least 75 per cent common share equity. The capital structure of Fortis is presented in the following table.

	December 31, 2006		December 31, 2005	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash)	**2,700.0**	**61.1**	2,182.5	58.7
Preference shares (1)	**442.0**	**10.0**	319.5	8.6
Common shareholders' equity (2)	**1,275.6**	**28.9**	1,213.4	32.7
Total	**4,417.6**	**100.0**	3,715.4	100.0

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

(2) On January 18, 2007, Fortis issued 5,170,000 Common Shares for proceeds of $149.9 million, $145.6 million net of after-tax expenses, improving the common shareholders' equity component of the capital structure to approximately 32 per cent and total preferred and common shareholders' equity to approximately 42 per cent.

The change in the Corporation's capital structure is primarily the result of the issue in September 2006 of 5,000,000 4.90% First Preference Shares, Series F for proceeds of $122.5 million, net of after-tax expenses, increased debt primarily to finance the consolidated capital program of Fortis and debt associated with Fortis Turks and Caicos and Caribbean Utilities, combined with net earnings, less common share dividends, of $74.6 million during 2006.

As at December 31, 2006, the Corporation's unsecured debt credit ratings were as follows:

Standard & Poor's	BBB
DBRS	BBB(high)

Capital Program: The Corporation's principal business of regulated utilities is capital intensive. Capital investment in electrical infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred.

Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2006, gross consolidated electric utility capital expenditures of Fortis were $483.1 million. Approximately 38 per cent of these expenditures was incurred to ensure the continued and enhanced performance, reliability and safety of the Corporation's generation, transmission and distribution assets; 45 per cent was incurred to meet customer growth; and the remaining 17 per cent was related to facilities, equipment, vehicles and information technology systems. Gross consolidated electric utility capital expenditures for 2007 are expected to be approximately $610 million. Approximately 33 per cent of these expenditures is expected to be incurred to ensure the continued and enhanced performance, reliability and safety of the Corporation's generation, transmission and distribution assets; 46 per cent is expected to meet customer growth; and the remaining 21 per cent is expected to relate to facilities, equipment, vehicles and information technology systems. Planned capital expenditures are based on detailed forecasts such as customer demand, weather, cost of labour and materials, as well as other factors which could change and cause actual expenditures to differ from forecasts.

Capital investment at FortisAlberta and FortisBC represented approximately 73 per cent of gross consolidated electric utility capital expenditures in 2006 and is expected to represent approximately 65 per cent of gross consolidated electric utility capital expenditures in 2007. The rate bases of FortisAlberta and FortisBC have increased approximately 29 per cent and 36 per cent, respectively, since the utilities were acquired in May 2004. Over the next two years, each utility's rate base is expected to grow by approximately 30 per cent.

Gross consolidated electric utility capital expenditures over the next five years are expected to surpass $2.6 billion. The Corporation's total electric utility capital assets are expected to grow at an average annual rate of approximately 7 per cent over the next five years. Growth in electric utility capital assets is expected to be driven by FortisAlberta and FortisBC and their need to enhance electrical system reliability and meet strong customer growth.

Generally, the regulatory processes at the Corporation's regulated utilities allow for a recovery of the cost of capital assets through amortization and/or a rate of return on the unamortized balance of capital assets. FortisBC, Newfoundland Power and Maritime Electric require regulatory approval of their capital expenditure plans. At the Corporation's other regulated electric utilities, prior regulatory approval of capital expenditure plans is not required. Instead, the regulatory authorities approve revenue requirements for the purpose of setting electricity 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 approval will not be imposed. Capital cost overruns might not be recoverable in future customer electricity rates.

Actual gross consolidated electric utility capital expenditures for 2006 exceeded planned gross consolidated electric utility capital expenditures of $430 million by approximately $53 million. The increase was driven by FortisAlberta and the need to connect new customers as a result of strong economic growth experienced in Alberta. Capital expenditures at FortisAlberta in excess of those forecasted when customer rates were last approved by the AEUB are expected to be included in rate base in 2008 for the purpose of establishing customer rates for that year.

A summary of gross electric utility capital expenditures for 2006 by segment and asset category is illustrated in the following table.

Gross Electric Utility Capital Expenditures

Year Ended December 31, 2006

($ millions)	Fortis Alberta[(1)(2)]	FortisBC[(1)]	NF Power[(1)]	Other Regulated Utilities Canadian[(1)]	**Total Regulated Utilities Canadian**	**Regulated Utilities Caribbean**	**Non-Regulated**	**Total[(3)]**
Generation	–	13.8	6.2	4.4	**24.4**	**3.7**	**3.2**	**31.3**
Transmission	–	44.1	9.1	7.2	**60.4**	**4.4**	**–**	**64.8**
Distribution	190.5	39.4	35.4	23.3	**288.6**	**13.1**	**1.6**	**303.3**
Facilities, equipment and vehicles	33.6	8.6	5.5	1.8	**49.5**	**4.7**	**–**	**54.2**
Information technology	19.1	5.0	4.0	0.5	**28.6**	**0.9**	**–**	**29.5**
Total	**243.2**	**110.9**	**60.2**	**37.2**	**451.5**	**26.8**	**4.8**	**483.1**

(1) At FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric, gross utility capital expenditures included removal and site restoration expenditures. These expenditures are permissible in rate base.

(2) Excludes payments of $17.5 million made to the AESO for investment in transmission facilities

(3) Includes expenditures associated with assets under construction

A summary of forecast gross electric utility capital expenditures for 2007 by segment and asset category is illustrated in the following table.

Forecast Gross Electric Utility Capital Expenditures
Year Ended December 31, 2007

($ millions)	Fortis Alberta(1)(2)	FortisBC(1)(3)	NF Power(1)	Other Regulated Utilities Canadian(1)	**Total Regulated Utilities Canadian**	**Regulated Utilities Caribbean**	**Non-Regulated**	**Total**
Generation	–	21.9	19.8	2.5	**44.2**	**29.7**	**19.6**	**93.5**
Transmission	–	64.4	8.3	5.5	**78.2**	**9.6**	**–**	**87.8**
Distribution	185.0	30.3	27.5	20.7	**263.5**	**36.8**	**1.3**	**301.6**
Facilities, equipment and vehicles	51.5	16.3	4.4	1.2	**73.4**	**21.9**	**–**	**95.3**
Information technology	19.1	6.0	3.5	1.7	**30.3**	**1.5**	**–**	**31.8**
Total	**255.6**	**138.9**	**63.5**	**31.6**	**489.6**	**99.5**	**20.9**	**610.0**

(1) At FortisAlberta, Newfoundland Power and Maritime Electric, forecast gross utility capital expenditures include removal and site restoration expenditures. These expenditures are permissible in rate base.
(2) Excludes forecast payments of approximately $17 million to the AESO for investment in transmission facilities
(3) At FortisBC, forecast gross utility capital expenditures reflect the 2007 Capital Plan submitted to the BCUC and subsequently approved, subject to further regulatory processes on certain projects. It also includes forecast removal and site restoration expenditures. These expenditures are permissible in rate base.

The Corporation's individually significant gross electric utility capital expenditure projects are summarized in the table below.

Gross Electric Utility Capital Expenditures
Individual Projects >$10 million

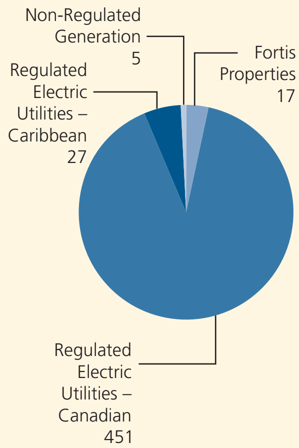
($ millions) **Utility**	**Nature of Project**	**Actual 2006**	**Expected costs to complete after 2006**	**Expected completion dates**
FortisAlberta	New operations facility in the City of Airdrie	**1.0**	28.0	2008
FortisAlberta	Automated Meter Infrastructure ("AMI") technology	**0.3**	85.0	2010
FortisBC	Three new substations and associated transmission lines	**8.1**	49.1	2007 and 2008
FortisBC	Generation asset upgrade and life-extension program	**10.8**	30.4	2011
Newfoundland Power	Rattling Brook hydroelectric generating plant refurbishment	**–**	18.8	2007
Caribbean Utilities	New 16-MW diesel generating unit	**6.5**	19.2	2007
Non-Regulated – Fortis Generation	New 18-MW hydroelectric generating facility – Vaca, Belize	**–**	61.0	2009

During 2007, FortisAlberta expects to spend $5.0 million associated with Phase 1 of the implementation of AMI technology. AMI technology will allow for more accurate reporting of customer consumption to retailers based on actual rather than estimated usage. AMI technology, once fully implemented, will reduce the costs of the current manual meter reading practice. FortisAlberta received AEUB approval to initiate Phase 1 of this project in 2007 and, based on the successful implementation of this first phase, Fortis will seek AEUB approval for the implementation of AMI technology to its remaining customers as part of its 2008/2009 Distribution Access Tariff Application. AMI technology is expected to be fully implemented by 2010 at an expected cost to complete after 2007 of approximately $80 million. A significant portion of FortisAlberta's 2006 and forecast 2007 capital expenditures is comprised of numerous smaller projects largely related to connecting new customers and capital replacements and upgrades.

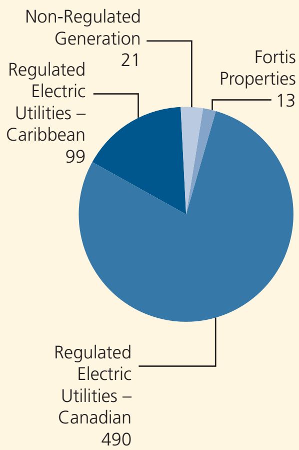
During 2006, work commenced at FortisBC on three new substations and associated transmission lines with an estimated total project cost of approximately $60 million, of which $2.5 million was spent in 2005 and $8.1 million was spent in 2006.

Since 1998, hydroelectric generating facilities at FortisBC have been subject to an upgrade and life-extension program which is forecast to conclude in 2011. Newly installed equipment is projected to enhance reliability and efficiency, while the use of standardized components is expected to reduce future maintenance and capital expenditures. No expenditures beyond 2008 have been included in the above table as they have not yet received regulatory approval.

2006 Consolidated Capital Expenditures *($ millions)*



2007 Forecast Consolidated Capital Expenditures *($ millions)*



During the year Fortis, through its indirect wholly owned subsidiary, BECOL, received approval of the Environmental Impact Assessment for the Vaca hydroelectric generating facility. Construction of the $61 million (US$52.5 million) 18-MW hydroelectric generating facility is expected to commence in 2007, pending regulatory approval. The run-of-river facility is expected to increase annual energy production from the Macal River by approximately 90 GWh to 250 GWh. BECOL has signed a 50-year power sales agreement with Belize Electricity for the sale of the energy generated by the Vaca facility, commencing in late 2009.

Consolidated maintenance and repairs expensed in 2006 associated with capital assets were approximately $58.7 million compared to approximately $53.8 million in 2005. Maintenance and repair expenses are generally determined by physical inspections and engineering assessments of the assets and are impacted by weather conditions and age of the assets. The Corporation expects the level of maintenance and repair expenses for 2007 for its existing operations to be higher than for 2006, driven primarily by the inclusion of Caribbean Utilities' results in the financial statements of Fortis on a consolidated basis in 2007.

The cash needed to complete the Corporation's consolidated capital expenditure program is expected to be supplied by a combination of long-term and short-term borrowings, internally generated funds and the issuance of common and preference shares. Fortis does not anticipate any difficulties with accessing the required capital.

Cash Flows: The Corporation's ability to service debt obligations and pay dividends on its common and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis.

At December 31, 2005, Belize Electricity was non-compliant with its debt service coverage ratio of 1.5 times related to its loans with the International Bank for Reconstruction and Development ("IBRD") and with the Caribbean Development Bank. A waiver was obtained for December 31, 2005 from IBRD. Belize Electricity's debt service coverage ratio improved during 2006 and, at December 31, 2006, Belize Electricity was compliant with its debt service coverage ratio of 1.5 times.

As at December 31, 2006, the Corporation and its subsidiaries had consolidated authorized lines of credit of $952.0 million, of which $546.7 million was unused. The following summary outlines the Corporation's credit facilities by reporting segments as at December 31st.

Credit Facilities

($ millions)	Corporate	Regulated Utilities	Fortis Generation	Fortis Properties	**Total 2006**	Total 2005
Total credit facilities	315.0	622.2	2.3	12.5	**952.0**	747.1
Credit facilities utilized						
Short-term borrowings	–	(94.3)	–	(3.4)	**(97.7)**	(48.9)
Long-term debt	(84.1)	(151.4)	–	–	**(235.5)**	(85.8)
Letters of credit outstanding	(4.6)	(65.3)	–	(2.2)	**(72.1)**	(73.6)
Credit facilities available	226.3	311.2	2.3	6.9	**546.7**	538.8

At December 31, 2006 and December 31, 2005, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In January 2006, Newfoundland Power renegotiated its $100 million committed credit facility, extending the term from one year to three years, with maturity now in January 2009.

In January 2006, Maritime Electric's $25 million non-revolving unsecured short-term bridge financing was extended until July 2007. In August 2006, the amount available on Maritime Electric's operating credit facilities was increased to $30 million from $25 million.

In March 2006, FortisAlberta amended its committed unsecured credit facility, increasing the amount available to $200 million from $150 million and extending the maturity date from May 2008 to May 2010. In addition, the Company, with the consent of the lenders, has the ability to request an increase in the limit of this credit facility by $50 million under the same terms as the existing credit facility. In July 2006, FortisAlberta entered into a demand credit facility for $10 million, increasing the amount available to the Company under unsecured demand credit facilities to $20 million.

In May 2006, the maturity date of FortisBC's $50 million 364-day operating credit facility was extended to May 2007.

In June 2006, Fortis renegotiated and amended its $145 million and $50 million unsecured credit facilities, extending the maturity dates of these facilities from May 2008 and January 2009 to May 2010 and January 2011, respectively. Additionally, in July 2006, the amount available under the committed unsecured $145 million facility was increased to $250 million. These credit facilities can be used for general corporate purposes, including acquisitions.

At December 31, 2006, Regulated Utilities' credit facilities included both a US$2.0 million overdraft facility and a US$9.0 million standby credit facility for hurricane damage at Fortis Turks and Caicos. No drawings were made on these facilities as at December 31, 2006.

At December 31, 2006, Regulated Utilities' credit facilities included a total of US$22.7 million related to Caribbean Utilities, consisting of a US$10.0 million capital expenditures line of credit, a US$5.0 million operating line of credit, a US$5.0 million catastrophe standby loan and US$2.7 million in letters of credit and corporate credit card line. On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit to US$17.0 million and increasing each of its US$5.0 million operating line of credit and US$5.0 million catastrophe standby loan to US$7.5 million, for total credit facilities of US$34.7 million. These changes to the credit facilities in November 2006 have not been reflected in the table above as the Corporation consolidated the balance sheet of Caribbean Utilities as at November 7, 2006.

Off-Balance Sheet Arrangements

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. The Corporation had no such off-balance sheet arrangements as at December 31, 2006.

Business Risk Management

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

Regulation: The Corporation's key business risk is regulation. Total regulated assets were approximately 86 per cent of total assets as at December 31, 2006 (December 31, 2005 – 85 per cent). Each of the Corporation's regulated utilities is subject to some form of regulation which can impact future revenues and earnings. Management at each operating 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 84 per cent of the Corporation's operating revenue and equity income was derived from regulated utility operations in 2006 (2005 – 84 per cent), while approximately 75 per cent of the Corporation's operating earnings was derived from regulated utility operations in 2006 (2005 – 74 per cent). These regulated operations – 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. These uncertainties include approvals by the respective regulatory authorities of electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, continuation of licences. The ability of the utilities to recover the actual costs of providing services and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. Upgrades of existing electricity systems and facilities and the addition of new electrical 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 electricity 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.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, negatively affect the Corporation's results of operations or financial position.

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

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or 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, which could adversely affect the ability of the utilities to earn reasonable returns on capital.

Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of interest rates. Earnings of such regulated utilities are exposed to changes in interest rates associated with rate-setting mechanisms. The rate of return is either directly impacted through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes appropriate returns on investment. Automatic adjustment mechanisms currently apply to FortisAlberta, FortisBC and Newfoundland Power. Due to declining long-term Canada bond yields and the operation of the automatic adjustment mechanisms, the allowed ROEs for these utilities have been reset. The 2006 allowed ROEs for FortisAlberta, FortisBC and Newfoundland Power were 8.93 per cent, 9.20 per cent and 9.24 per cent, respectively. Effective January 1, 2007, the allowed ROEs for FortisAlberta, FortisBC and Newfoundland Power have been lowered to 8.51 per cent, 8.77 per cent and 8.60 per cent, respectively. Strong rate base growth at the Western Canadian utilities is expected to more than offset the impact of the lower allowed ROEs, while earnings at Newfoundland Power are expected to be slightly lower in 2007.

Energy Prices: The Corporation's primary exposure to changes in energy prices relates to its non-regulated energy sales in Ontario. Energy is sold to the IESO at market prices. The sensitivity of the Corporation's earnings to each $1 per MWh change in the annual average wholesale market price of electricity in Ontario is expected to be approximately $0.4 million. 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 Generating Station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will not be renewed, effective May 1, 2009. During 2006, earnings contribution associated with the Niagara Exchange Agreement was $14.2 million. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. Effective January 1, 2007, all energy produced by these assets is sold to 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.

Economic Conditions: Typical of electric utilities, the general economic conditions of the Corporation's service territories influence electricity sales. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts.

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 possible downturns. The high quality of the real estate and hotel assets and commitment to productivity improvement reduce the exposure to industry fluctuations and possible downturns. Fortis Properties' real estate investments are anchored by high-quality tenants with long-term leases. Exposure to lease expiries averages approximately 10 per cent per annum over the next five years. Approximately 52 per cent of Fortis Properties' operating income was derived from hotel investments in 2006 (2005 – 51 per cent). Management believes that, based on the nature of its business, the Corporation is not exposed to a significant reduction in revenues. A 5 per cent decrease in revenues from the Hospitality Division would reduce earnings by approximately $1.3 million.

Weather: The physical assets of the Corporation and its operating subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, 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 by a regulatory mechanism, as approved by the PUB, through the operation of a weather normalization reserve. The operation of this reserve mitigates year-over-year volatility in earnings that would otherwise be caused by variations in weather conditions.

Despite preparation for severe weather, extraordinary conditions, like Hurricane Ivan in September 2004, and other natural disasters will always remain a risk to utilities. Upon acquiring controlling interest in Caribbean Utilities and upon the acquisition of Fortis Turks and Caicos, the Corporation's exposure to risks from natural disasters in the Caribbean region has increased. Except for Caribbean Utilities and Fortis Turks and Caicos, the Corporation uses a centralized insurance management function to create a higher level of insurance expertise and to 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. The PUC provides for recovery of certain costs arising from hurricanes through a surcharge on electricity rates, thereby mitigating the financial impact to Belize Electricity. In 2005, the Government of the Cayman Islands approved a hurricane CRS for a period of approximately three years, effective August 1, 2005. This CRS recovers a significant portion of previously expensed direct uninsured Hurricane Ivan losses.

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

Derivative Instruments and Hedging: Derivative instruments, such as interest rate swap contracts, are used only to manage risk and are not used for trading purposes. The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet and assesses, both at the hedge's inception and on an ongoing basis, whether the hedging transactions are effective in offsetting changes in cash flows of the hedged items. Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item. If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in earnings concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in earnings. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in earnings.

Fortis manages interest rate risk by locking in interest rates for long periods through fixed-rate debt and interest rate swap contracts. The Corporation's interest rate swap contracts, as outlined in Note 11 to the 2006 Fortis Inc. Annual Consolidated Financial Statements, are accounted for as hedges against the associated long-term debt. Changes in the market value of the interest rate swap contracts, which fluctuate over time, are not recognized until interest payments are made. The Corporation's interest rate hedging programs are typically unaffected by changes in market conditions as interest rate swaps are generally held to maturity, consistent with the objective to lock in interest rate spreads on the hedged item. Approximately 74 per cent of the Corporation's long-term debt facilities and capital lease obligations have maturities beyond five years. The Corporation's exposure to interest rate risk is primarily associated with short-term borrowings and other variable interest credit facilities.

The following table outlines the nature of the Corporation's debt as at December 31, 2006.

Total Debt

at December 31, 2006	*($ millions)*	*(%)*
Short-term borrowings	**97.7**	**3.6**
Utilized variable rate credit facilities classified as long-term	**235.5**	**8.6**
Variable rate long-term debt and capital lease obligations (including current portion)	**17.0**	**0.6**
Fixed rate long-term debt and capital lease obligations (including current portion)	**2,390.7**	**87.2**
Total	**2,740.9**	**100.0**

The Corporation's earnings from its foreign net investments are exposed to changes in US dollar exchange rates. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with earnings from its foreign net investments through the use of US dollar borrowings. As a result of the Corporation's hedging strategy, the estimated annual sensitivity to each 4-cent increase in the US dollar exchange rate will result in approximately a 1-cent increase in the Corporation's earnings per common share. As at December 31, 2006, the US dollar to Canadian dollar foreign exchange rate was US$1.00 = CDN$1.17 (December 31, 2005 – US$1.00 = CDN$1.16).

Prior to the acquisition of Fortis Turks and Caicos in August 2006 and controlling interest in Caribbean Utilities in November 2006, the Corporation's earnings were impacted by foreign currency exchange rate fluctuations associated with the translation of US dollar borrowings not designated as a hedge against the Corporation's foreign net investments. Immediately prior to the acquisition of Fortis Turks and Caicos, Fortis had US$32 million (December 31, 2005 – US$55 million) of US dollar borrowings in excess of the Corporation's foreign net investments, which did not qualify for hedge accounting. Consequently, fluctuations in the carrying value of this debt, resulting from foreign currency exchange rate fluctuations, were recorded in earnings in each reporting period. The Corporation's foreign net investments increased upon the acquisition of Fortis Turks and Caicos, thereby allowing the US$32 million and the incremental US dollar borrowings associated with the acquisition of Fortis Turks and Caicos to be designated as a hedge against this foreign net investment. The US dollar debt associated with the acquisition of controlling interest in Caribbean Utilities qualified for hedge accounting and was designated as a hedge against this foreign net investment. Previously, the Corporation's equity accounted investment in Caribbean Utilities did not qualify for hedge accounting purposes as a foreign net investment. As at December 31, 2006, all of the Corporation's US$258.6 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's US dollar borrowings designated as hedges are recorded in the Corporation's foreign currency translation adjustment account in shareholders' equity. As at December 31, 2006, the Corporation had approximately US$121 million in foreign net investments available to be hedged.

Management will continue to hedge future exchange rate fluctuations related to its foreign net investments and US dollar earnings streams, where possible, through the use of future US dollar borrowings and will monitor the exposure of Fortis to foreign currency fluctuations on a regular basis.

Capital Resources: The Corporation's financial position could be adversely affected if it or its operating subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. 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 and anticipated capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

Generally, the Corporation and its regulated utilities are subject to financial risk associated with changes to the credit ratings assigned to them by credit rating agencies. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation.

Loss of Service Area: FortisAlberta serves a number of direct customers that reside 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 AEUB approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost, less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of its rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently initiated pursuant to the *Municipal Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within the boundaries of the municipality, the loss of which could have a material adverse affect on the financial condition and results of operations of FortisAlberta.

Licences and Permits: The acquisition, ownership and operation of 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 electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

Environment: The Corporation and its operating 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 and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Corporation. The process of obtaining environmental, health and safety regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. Environmental damage and other costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. However, there can be no assurance that such costs will be recoverable through customer rates at the regulated utilities and, if substantial, unrecovered costs may have a material adverse effect on the business, results of operations, financial condition and prospects of the Corporation.

Insurance: While the Corporation and its operating subsidiaries maintain insurance, a significant portion of the Corporation's regulated 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 operating 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 operating 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 business, results of operations, financial condition and prospects.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its operating 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.

Labour Relations: Approximately 50 per cent of the employees of the Corporation's operating subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the operating subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business 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 to 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 an adverse effect on the results of operations, cash flow and earnings of the Corporation.

The collective agreement between FortisBC and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expired on January 31, 2005. IBEW represents employees in specified occupations in the areas of generation, transmission and distribution. The Company and IBEW reached an agreement, which was ratified in early January 2006, which expires on January 31, 2008. The collective agreement between FortisBC and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired on January 31, 2006. COPE represents employees in office and professional occupations. The Company and COPE reached an agreement which was ratified in early July 2006 and expires on January 31, 2011.

The majority of employees at FortisAlberta are represented by the United Utility Workers' Association ("UUWA"). There were two collective agreements with the UUWA. The Dispatch/Contact Centre Collective Agreement expired December 31, 2004 and the main collective agreement expired December 31, 2005. A new combined agreement was reached with the UUWA during the second quarter of 2006 and expires on December 31, 2007. FortisAlberta plans to initiate bargaining with the UUWA in the fall of 2007.

Belize Electricity's collective agreement with the Belize Energy Workers Union was signed on November 29, 2000 and is to be reviewed every five years. Negotiations commenced during the third quarter of 2006 for a new collective agreement and are ongoing.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of its operating subsidiaries to attract, develop and retain a skilled workforce. Like other utilities across Canada and the Caribbean, Fortis' 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. In particular, Alberta has a highly competitive job market where the demand for certain job skills exceeds the supply making it difficult to attract new employees.

Liquidity Risk: Earnings from Belize Electricity are denominated in Belizean dollars, earnings from Caribbean Utilities are denominated in Cayman Island dollars and earnings from FortisUS Energy, BECOL and Fortis Turks and Caicos are denominated in US dollars. As at December 31, 2006, both the Cayman Island dollar and the Belizean dollar are pegged to the US dollar: CI$0.84 = US$1.00; BZ$2.00 = US$1.00. Foreign earnings derived in currencies other than the US dollar must be converted into US dollars before repatriation, presenting temporary liquidity risks. Due to the small size and cyclical nature of the economy in Belize, conversion of local currency into US dollars may be subject to restrictions from time to time.

Change in Presentation

Prior to December 31, 2006, the regulatory provision at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric for future removal and site restoration costs was part of amortization expense and was recorded in accumulated amortization, as these costs were recoverable in amortization rates from customers. Actual costs of removal and site restoration incurred, net of salvage proceeds, were recorded against this provision in accumulated amortization. In accordance with Canadian GAAP, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record removal and site restoration costs in earnings as incurred. In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric would be recognized as incurred rather than over the life of the asset through amortization expense. The Corporation has changed the presentation of the provision for future removal and site restoration as a regulatory liability rather than including it with accumulated amortization. This change in presentation has been applied retroactively, with restatement of 2005 comparative balances, and has had no impact on earnings. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a corresponding $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets resulting from a decrease in accumulated amortization.

Changes in Accounting Policies

Revenue Recognition: Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy from a billed basis to an accrual basis, as approved by the PUB. The transition to recording revenue on an accrual basis had no material impact on Newfoundland Power's annual earnings, but resulted in a shift in the Company's 2006 quarterly earnings compared to 2005. Adoption of the accrual method for revenue recognition gave rise to a $23.6 million balance sheet accrual for unbilled revenue at December 31, 2005. The PUB approved the recognition of $3.1 million in 2006 and $2.7 million in 2007 of the 2005 unbilled revenue as revenue in these years to offset the income tax impact of changing to the accrual method for revenue recognition. The disposition of the remaining 2005 unbilled revenue will be determined by future orders of the PUB.

Conditional Asset Retirement Obligations: On April 1, 2006, Fortis retroactively adopted Emerging Issues Committee Abstract – 159, *Conditional Asset Retirement Obligations* ("EIC 159"). EIC 159 requires an entity to recognize a liability for the fair value of an asset retirement obligation ("ARO") even though the timing and/or method of settlement are conditional on future events. While conditional AROs have been identified, no amounts have been recorded as they are immaterial to the Corporation's results of operations and financial position. The Corporation also has AROs that cannot be reasonably estimated at this time as the final date of removal of the related assets and the costs to do so cannot be reasonably determined, as the assets are reasonably expected to operate in perpetuity due to the nature of their operation.

Corporate Income Taxes: Effective January 1, 2006, FortisAlberta is following the taxes payable method of accounting for federal income taxes. As prescribed by the 2006/2007 Negotiated Settlement Agreement, approved by the AEUB on June 29, 2006, corporate income tax expenses are now recovered through customer rates based only on income taxes that are currently payable for regulatory purposes. Therefore, current rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. Accordingly, FortisAlberta no longer recognizes income taxes deferred to future years as a result of the specified temporary differences. The Company only recognizes future income taxes for certain deferral amounts where the future income taxes will not be collected in future customer rates.

In 2005, FortisAlberta followed the taxes payable method of accounting only for provincial income taxes because federal income tax expenses were recovered through customer rates based on a modified liability method. Under the modified liability method, customer rates included the recovery of future federal income taxes related to specified temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes. As a result, FortisAlberta previously recognized future federal income taxes and set up a regulatory liability equal to the amount of future federal income taxes recognized that had not yet been reflected in customer rates. However, due to the AEUB-approved 2006/2007 Negotiated Settlement Agreement, the future income tax asset and offsetting regulatory liability were no longer recognized, which resulted in a $50.7 million reduction in the Corporation's future income tax assets and regulatory liabilities during the second quarter of 2006. Had FortisAlberta accounted for its regulated operations using the liability method in 2006, the Corporation would have had additional future income tax assets of approximately $56.3 million at December 31, 2006 and would have recognized additional future income tax expense of approximately $17.7 million for the year ended December 31, 2006. However, there would have been no net earnings impact associated with the additional future income tax expense as FortisAlberta would have recorded an offsetting regulatory asset for future recovery in customer rates.

Employee Future Benefits: Effective January 1, 2006, as prescribed by the AEUB-approved 2006/2007 Negotiated Settlement Agreement, FortisAlberta is recovering in customer rates other post-employment benefits and supplemental pension plan costs based on the cash payments made. However, any difference between the expense recognized under Canadian GAAP and that recovered from customers in current customer rates for other post-employment and pension plans, which is expected to be recovered or refunded in future customer rates, is subject to deferral treatment and is recorded as a regulatory asset on the balance sheet. The change in how other post-employment benefits and supplemental pension plan costs are recovered in customer rates had no impact on the Corporation's earnings in 2006.

Future Accounting Pronouncements

Comprehensive Income, Financial Instruments and Hedges: New accounting standards for comprehensive income, financial instruments (recognition, measurement, presentation and disclosure) and hedges have been issued by the Canadian Institute of Chartered Accountants ("CICA") and are effective for the Corporation for the fiscal year beginning January 1, 2007. These standards are intended to harmonize Canadian GAAP with US GAAP and with International Financial Reporting Standards.

The new comprehensive income standard provides guidance for the reporting and display of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources including unrealized foreign currency translation amounts, net of hedging arising from self-sustaining foreign operations, and changes in the fair value of the effective portion of cash flow hedging instruments. The Corporation expects to report a Statement of Comprehensive Income upon adoption of this new standard.

The financial instruments standards address the criteria for recognition and presentation of financial instruments on the balance sheet and the measurement of financial instruments according to prescribed classifications. The standards also address how the financial instruments are measured subsequent to initial recognition and how the gains and losses are recognized. All financial instruments, including derivatives and derivative features embedded in financial instrument or other contracts but which are not considered closely related to the host financial instrument or contract, are required to be initially recorded at fair value. The classification of financial instruments determines whether they are to be remeasured at each balance sheet date at fair value or at amortized cost and whether any resulting gains or losses are recognized in earnings or in other comprehensive income. Based on the expected classification of the Corporation's financial assets and liabilities, these financial assets and liabilities would be recorded at amortized cost, which is not expected to be materially different than the carrying value of these items. Under the new standards, deferred financing costs are no longer recognized as a deferred charge and Fortis expects to recognize unamortized deferred financing costs as part of its debt balances. These costs are required to be amortized using the effective interest method versus the straight-line method. This change in methodology is not expected to have a material impact on the Corporation's earnings. Currently, the Corporation limits the use of free-standing derivative financial instruments and, therefore, does not expect that the recognition of derivatives at fair value upon adoption of the new financial instrument standards will have a material impact on the Corporation. The Corporation is in the process of finalizing its assessment of contracts for embedded derivatives, including debt prepayment options, to determine whether or not they are considered closely related to the host contract and require fair value recognition.

The new accounting standard for hedges specifies the criteria under which hedge accounting is applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures. The Corporation expects its three existing interest rate swaps will continue to qualify for hedge accounting as cash flow hedges under the new standard. Gains or losses on the interest rate swaps would be recorded in other comprehensive income and reclassified to earnings in the periods in which earnings are effected by the variable-rate interest payments. Under the new standard, the Corporation expects that foreign exchange gains or losses on its US dollar borrowings designated as hedges of the Corporation's net investment in US dollar-denominated self-sustaining foreign operations will be recognized in other comprehensive income.

Rate-Regulated Operations: The Canadian Accounting Standards Board ("AcSB") recently considered the effects on its rate-regulated operations project of its recently adopted Strategic Plan and decided that the project, as originally planned, should be discontinued. It further decided, subject to exposure of its proposals, that: (i) the temporary exemption in Section 1100 of the CICA Handbook providing relief to entities subject to rate regulation from the requirement to apply that Section to the recognition and measurement of assets and liabilities arising from rate regulation should be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, should be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, should be retained as is. The Canadian AcSB also observed that relying on US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71"), as another source of Canadian GAAP in the absence of CICA Handbook guidance addressing the specific circumstances of entities subject to rate regulation, is consistent with Section 1100 when the qualifying criteria of FAS 71 are met.

The Corporation is following these developments closely and is in the process of assessing the potential impact on its financial statements. No Exposure Draft for public comment based on these preliminary decisions has been issued to date.

Financial Instruments

The carrying values of financial instruments included in current assets and current liabilities in the consolidated balance sheets of Fortis approximate their fair value, reflecting the short-term maturity and normal trade credit terms of these instruments. The fair value of the long-term debt and capital lease obligations is based on current pricing of financial instruments with comparable terms. The fair value of the preference shares is determined using quoted market prices. The fair values of interest rate swap contracts reflect the estimated amount that the Corporation would have to pay if forced to settle all outstanding contracts at year end. This fair value reflects a point-in-time estimate that may not be relevant in predicting the Corporation's future earnings or cash flows.

The carrying and fair values of the Corporation's long-term debt and capital lease obligations, preference shares and interest rate swap contracts as at December 31st were as follows.

As at December 31st *($ millions)*	**2006** **Carrying Value**	**2006** **Fair Value**	2005 Carrying Value	2005 Fair Value
Long-term debt and capital lease obligations	**2,643.2**	**2,968.6**	2,167.1	2,492.6
Preference shares[(1)]	**442.0**	**483.9**	319.5	369.1
Interest rate swap contracts	**–**	**(0.5)**	–	(0.9)

[(1)] Includes preference shares classified as both equity and long-term liabilities

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected future regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2006, Fortis recorded $168.7 million in current and long-term regulatory assets (December 31, 2005 – $115.6 million) and $365.3 million in current and long-term regulatory liabilities (December 31, 2005 – $387.1 million). The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2006 Fortis Inc. Annual Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. The Corporation's consolidated utility and income producing capital assets represented approximately 74 per cent of total consolidated assets as at December 31, 2006 (December 31, 2005 – 72 per cent). Amortization expense associated with capital assets was $167.0 million during 2006 (2005 – $147.2 million). Due to the size of the Corporation's capital assets, changes in amortization rates can have a significant impact on amortization expense.

As part of the customer rate setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount to provide for future removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2006 was $306.5 million (December 31, 2005 – $280.9 million). The amount of future removal and site restoration costs provided for and reported in amortization expense during 2006 was $29.5 million (2005 – $21.7 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization as a result of actual experience differing from that expected and provided for in previous amortization rates is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates.

FortisBC recently completed a depreciation study on the estimated useful life of its utility capital assets which recommended an increase in the Company's composite amortization rate. The BCUC-approved 2006 Negotiated Settlement Agreement resulted in an increase in the composite amortization rate from 2.6 per cent to 3.2 per cent, effective January 1, 2006, the impact of which increased the Corporation's amortization costs by approximately $4.6 million over last year. The impact of increased amortization rates was reflected in FortisBC's 2006 BCUC-approved customer electricity rates.

Capitalized Overhead: As required by their respective regulators, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2006, GEC totalled $18.2 million (2005 – $11.8 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a significant impact on the amount recorded as operating expenses and utility capital assets. FortisBC recently completed an analysis of its capitalized overhead allocation method. This analysis supported a change in the estimate of capitalized overhead. The changed estimate calculates capitalized overhead as a percentage of all FortisBC corporate overhead, whereas previously the percentage was applied to a limited pool of FortisBC corporate costs. The BCUC-approved 2006 Negotiated Settlement Agreement resulted in an increase in the amount of capitalized overhead, effective January 1, 2006, from approximately 9 per cent of BCUC-approved 2005 forecast gross operating and maintenance expenses to 20 per cent of BCUC-approved 2006 forecast gross operating and maintenance expenses. The impact of this change in estimate has decreased operating expenses by approximately $5.0 million compared to last year. The impact of the increased capitalized overhead rate was reflected in FortisBC's 2006 BCUC-approved customer electricity rates.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill, which is based on current information and fair market value assessments of the reporting units being reviewed. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $661.3 million in goodwill recorded on the Corporation's balance sheet as at December 31, 2006.

Employee Future Benefits: The Corporation's defined benefit pension plans and other post-employment benefit plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations were the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets. Other assumptions applied were average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions were also utilized by management in determining other post-employment benefit plan expense and obligations. Assumptions were also made regarding the health care cost trend increase. FortisAlberta and Newfoundland Power record the cost of pension and/or other post-employment benefit plan expense on a cash basis. Therefore, changes in assumptions do not impact earnings of those subsidiaries. As at December 31, 2006, the Corporation had a consolidated accrued benefit asset of $102.0 million (December 31, 2005 – $97.2 million) and a consolidated accrued benefit liability of $63.7 million (December 31, 2005 – $53.6 million). During 2006, the Corporation recorded consolidated net benefit expenses of $19.7 million (2005 – $16.2 million).

The following tables reflect the sensitivities associated with a 0.5 per cent increase and a 0.5 per cent decrease in the expected long-term rate of return on plan assets and discount rate on 2006 net benefit expense, accrued benefit pension asset and liability recorded in the Corporation's consolidated financial statements as well as the impact on the benefit obligation. The sensitivity analysis primarily applies to the Corporation's Regulated Utilities – Canadian segment.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2006

($ millions)	Net benefit expense	Accrued benefit asset	Accrued benefit liability	Benefit obligation
Impact of increasing the rate of return assumption by 0.5 per cent	(1.7)	1.5	(0.2)	–
Impact of decreasing the rate of return assumption by 0.5 per cent	1.7	(1.5)	0.2	–
Impact of increasing the discount rate assumption by 0.5 per cent	(2.7)	1.8	(0.9)	(33.5)
Impact of decreasing the discount rate assumption by 0.5 per cent	3.0	(2.0)	1.0	37.1

Asset Retirement Obligations: In measuring the fair value of AROs, the Corporation is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the system and the remediation of certain leased land, there were no amounts recorded as at December 31, 2006 and 2005. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation facilities are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of electricity service to customers; and the land lease agreement at Maritime Electric is expected to be renewed indefinitely. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize electricity revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Prior to January 1, 2006, Newfoundland Power also recognized electricity revenue on a billed basis. Effective January 1, 2006, Newfoundland Power adopted, on a prospective basis, the accrual method for recognizing revenue as approved by the PUB. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by the customer since the last meter reading. The unbilled revenue accrual for the period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments of electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2006, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $131.8 million (December 31, 2005 – $99.5 million) on annual consolidated operating revenues of $1.46 billion (2005 – $1.43 billion).

Contingencies: Fortis is a party to a number of disputes and lawsuits in the normal course of business. The following describes the nature of the Corporation's significant contingent liabilities.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all aspects of the reassessment and filed a Notice of Objection with the Chief of Appeals at CRA. Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $12.1 million in taxes and accrued interest. As at December 31, 2006, Maritime Electric has provided for, through future and current income taxes payable, approximately $11.6 million and, therefore, an additional liability of $0.5 million would arise. In this event, the Company would apply to IRAC to include this amount in the regulatory rate-making process. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA and the Company made a payment on deposit of $5.9 million with CRA on June 29, 2006.

FortisAlberta

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately $2.7 million in fire-fighting and suppression costs and approximately $2.4 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date leads management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, given the preliminary stage of the proceedings, FortisAlberta has not made any definitive assessment of potential liability with respect to the claim. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

The B.C. Ministry of Forests (the "Ministry") 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. The Company is currently communicating with the Ministry and its insurers. In addition, FortisBC has been served with two filed writs and statements of claim by private land owners in relation to this matter. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

On January 5, 2006, FortisBC was served with a writ and statement of claim filed with the B.C. Supreme Court under the *Class Proceedings Act, 1995* (British Columbia) on behalf of a class consisting of all persons who are or were customers of FortisBC and who paid or have been charged FortisBC's late payment penalties at any time between April 1, 1981 and the date of any judgment in this action. The claim is that forfeitures of the prompt payment discount offered to customers constitute "interest" within the meaning of section 347 of the *Criminal Code* (Canada) and, since the effective annual rate of such interest exceeds 60 per cent, they are illegal and void. In the action, the Plaintiff seeks damages and restitution of all late payment penalties that were forfeited. On December 13, 2006, the application to certify the action as a class action was heard in the B.C. Supreme Court. In a decision delivered on January 11, 2007, the B.C. Supreme Court dismissed the application to certify the action as a class suit. The Plaintiff has filed an appeal of the decision with the B.C. Court of Appeal. The final outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisUS Energy

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the "Village"), New York. The Village 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 hydro site, located in the Village of Philadelphia municipality, now owned by FortisUS Energy, totalling approximately US$7.1 million (CDN$8.0 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. The Village, however, filed a notice of appeal in January 2007. Management believes that the appeal will not be successful and, therefore, no provision has been made in the consolidated financial statements.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2006, 2005 and 2004. The financial information has been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Years Ended December 31st *($ millions, except per share amounts)*	**2006**	2005	2004
Revenue and Equity Income(1)	**1,471.7**	1,441.5	1,146.1
Net earnings	**148.8**	137.1	90.9
Net earnings applicable to common shares	**147.2**	137.1	90.9
Total assets	**5,447.4**(2)	4,597.1(2)	3,938.0
Long-term debt and capital lease obligations (net of current portion)	**2,558.5**	2,135.7	1,904.4
Preference shares(3)	**442.0**	319.5	319.5
Common shareholders' equity	**1,275.6**	1,213.4	1,000.1
Earnings per common share	**1.42**	1.35	1.07
Diluted earnings per common share	**1.37**	1.24	1.01
Dividends declared per common share	**0.70**	0.61	0.55
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series D	**–**	0.03(4)	0.1706(5)
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	0.7733(5)
Dividends declared per First Preference Share, Series F(6)	**0.5211**	–	–

(1) Revenue reflects weather-adjusted values related to Newfoundland Power's Weather Normalization Reserve.

(2) As at December 31, 2006, the regulatory provision for future site removal and restoration costs at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric has been reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. This change in presentation resulted in an increase in total assets of $306.5 million (2005 – $280.9 million) and an increase in long-term regulatory liabilities of $306.5 million (2005 – $280.9 million).

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

(4) The First Preference Shares, Series D were redeemed in September 2005.

(5) The First Preference Shares, Series D and First Preference Shares, Series E were issued at various times during 2004 based on the exercise of warrants under the issuance of First Preference Units in January 2004.

(6) 5,000,000 First Preference Shares, Series F were issued on September 28, 2006, at $25.00 per share for net after-tax proceeds of $122.5 million and are entitled to receive cumulative dividends in the amount of $1.2250 per annum.

2006/2005 – Revenue, including equity income, increased 2.1 per cent over 2005. However, revenue at FortisAlberta last year included approximately $19.7 million largely related to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments. The increase in revenue was largely driven by electricity sales growth at FortisAlberta and FortisBC, increased electricity rates at FortisBC and Belize Electricity and four months of revenue contribution from Fortis Turks and Caicos, partially offset by lower average wholesale energy prices in Ontario. Equity income from Caribbean Utilities was $1.7 million lower than last year; however, equity income last year included a $1.1 million positive adjustment related to a change in Caribbean Utilities' accounting practice for recognizing unbilled revenue. Net earnings applicable to common shares grew 7.4 per cent; however, earnings last year included the $7.9 million after-tax Ontario Settlement gain. Growth in earnings was primarily driven by strong electricity sales growth at FortisAlberta and FortisBC, lower corporate income taxes at FortisAlberta, improved non-regulated hydroelectric generation in Belize, earnings growth at Fortis Properties, the overall 11 per cent increase in electricity rates at Belize Electricity, effective July 1, 2005, and four months of earnings contribution from Fortis Turks and Caicos. The increase was partially offset by lower average wholesale energy prices in Ontario and higher corporate costs. The growth in total assets and increase in long-term debt was primarily associated with the extensive capital expenditure programs at FortisAlberta and FortisBC, the acquisition of an additional 16 per cent ownership interest in Caribbean Utilities and the assumption of long-term debt upon consolidating the Corporation's resulting controlling ownership interest in Caribbean Utilities, and the acquisition of Fortis Turks and Caicos and four hotels in Western Canada and the assumption of related long-term debt. The Corporation also issued $122.5 million in preference shares in 2006 to partially fund the acquisition of Fortis Turks and Caicos and to fund equity injections into FortisAlberta and FortisBC in support of their extensive capital expenditure programs.

2005/2004 – Revenue, including equity income, and net earnings applicable to common shares in 2005 grew 25.8 per cent and 50.8 per cent, respectively, over 2004. A full year of operations for FortisAlberta and FortisBC, increased average wholesale energy prices in Ontario, increased electricity sales and/or rates in the Corporation's regulated utilities and the addition of revenue associated with the three Greenwood Inn hotels acquired on February 1, 2005 were the primary contributors to increased revenues. Equity income from Caribbean Utilities increased $10.6 million from 2004, primarily as a result of the recovery from Hurricane Ivan and the recognition in 2005 of the impact of a change in accounting practice for recognizing unbilled revenue. The increase in earnings in 2005 was due to a full year of earnings contributions from FortisAlberta and FortisBC, higher average wholesale energy prices in Ontario, higher equity income from Caribbean Utilities and the $7.9 million after-tax Ontario Settlement gain. The increase was partially offset by higher corporate finance charges associated with the acquisition of FortisAlberta and FortisBC in 2004. With the exception of Newfoundland Power, all operating segments reported improved financial results over 2004. Newfoundland Power's earnings declined slightly mainly due to a 51 basis point formula-driven reduction in its allowed ROE in 2005. The growth in total assets and long-term liabilities was primarily associated with the extensive capital programs at FortisAlberta and FortisBC and the acquisition of the three Greenwood Inn hotels.

The Corporation's dividend payout ratio was 47.2 per cent in 2006 compared to 43.7 per cent in 2005. In September 2006, Fortis declared an increase in the regular quarterly dividend to 19 cents per common share from 16 cents per common share, with the first payment occurring on December 1, 2006.

On February 8, 2007, Fortis announced that its Board of Directors had declared a 10.5 per cent increase in the quarterly common share dividend, increasing the amount from 19 cents per common share to 21 cents per common share, commencing with the second quarter dividend payable on June 1, 2007.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2005 through December 31, 2006. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	Revenue and Equity Income *($ thousands)*	Net Earnings Applicable to Common Shares *($ thousands)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2006	393,111	33,886	0.33	0.32
September 30, 2006	341,947	38,750	0.37	0.36
June 30, 2006	345,851	37,946	0.37	0.35
March 31, 2006	390,827	36,605	0.35	0.34
December 31, 2005	353,084	22,263	0.22	0.21
September 30, 2005	341,650	37,450	0.36	0.33
June 30, 2005	364,948	38,188	0.37	0.34
March 31, 2005	381,789	39,196	0.40	0.36

A summary of the past eight quarters reflects the Corporation's continued growth as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity demand and water flows as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. The Corporation's non-utility investment, Fortis Properties, generally produces its highest earnings in the second and third quarters. Financial results from February 1, 2005 were impacted by the acquisition of three Greenwood Inns. Also, the comparability of 2006 and 2005 quarterly earnings and revenue has been somewhat impacted by the shift in reported revenue at Newfoundland Power resulting from the change to the accrual basis for revenue recognition from the billed basis. Each of the comparative quarterly earnings, except for the comparative quarters ended March 31, 2006 and March 31, 2005 and comparative quarters ended June 30, 2006 and June 30, 2005, have increased as a result of both the Corporation's acquisition strategy and improved operating earnings at most subsidiaries. Results for the first quarter ended March 31, 2005 included the $7.9 million after-tax Ontario Settlement gain. Revenue and equity income and earnings were higher during the second quarter ended June 30, 2005 compared to the same quarter in 2006, primarily due to a $7.0 million positive after-tax adjustment to FortisAlberta's earnings driven largely by the resolution of tax-related matters pertaining to prior years.

December 2006/December 2005 – Net earnings applicable to common shares were $33.9 million, or $0.33 per common share, for the fourth quarter of 2006 compared to earnings of $22.3 million, or $0.22 per common share, for the fourth quarter of 2005. The increase in earnings was largely driven by Newfoundland Power due to a change in the Company's revenue recognition policy to the accrual method effective January 1, 2006, earnings growth at FortisAlberta and contributions from Fortis Turks and Caicos, acquired on August 28, 2006, partially offset by the impact of lower average wholesale energy prices in Ontario and increased corporate expenses. The change in the revenue recognition policy did not have a material impact on Newfoundland Power's annual earnings.

September 2006/September 2005 – Net earnings applicable to common shares were $38.8 million, or $0.37 per common share, for the third quarter of 2006 compared to earnings of $37.4 million, or $0.36 per common share, for the third quarter of 2005. Excluding $1.6 million of earnings during the third quarter of 2005 associated with the favourable resolution of a corporate income tax reassessment at FortisOntario, earnings were $3.0 million higher quarter over quarter. The increase was largely driven by improved non-regulated hydroelectric production in Belize, lower corporate taxes at FortisAlberta, increased electricity rates at FortisBC, higher earnings from Fortis Properties, higher earnings from Regulated Utilities – Caribbean due, in part, to the recent acquisition of Fortis Turks and Caicos and increased electricity rates at FortisOntario. The increase in quarterly earnings was partially offset by higher corporate expenses and lower average wholesale energy prices in Ontario. Corporate expenses during the third quarter of 2005 were reduced by a $3.8 million ($3.1 million after-tax) unrealized foreign currency translation gain associated with unhedged US dollar-denominated debt.

June 2006/June 2005 – Net earnings applicable to common shares were $37.9 million, or $0.37 per common share, for the second quarter of 2006 compared to earnings of $38.2 million, or $0.37 per common share, for the second quarter of 2005. Earnings for the second quarter of 2005 included a $7.0 million positive after-tax adjustment to FortisAlberta's earnings, driven largely by the resolution of tax-related matters pertaining to prior years, which favourably impacted revenue. Earnings for the second quarter of 2005 also included a $1.1 million positive adjustment to equity income from Caribbean Utilities related to a change in accounting practice for recognizing unbilled revenue. Excluding these items, the Corporation's earnings were $7.8 million higher in the second quarter of 2006 compared to the second quarter of 2005. The increase was driven by lower corporate income taxes largely at FortisAlberta, improved non-regulated hydroelectric production in Belize, higher earnings at Fortis Properties and an unrealized foreign exchange gain on the translation of US dollar-denominated long-term corporate debt. The increase was partially offset by lower earnings at Newfoundland Power related to the shifting of revenue from the first half of 2006 to the second half of 2006 upon adopting the accrual method of recognizing revenue, effective January 1, 2006, and the impact of recording the cumulative effects of the regulator-approved Negotiated Settlement Agreements during the second quarter of 2006 at FortisAlberta and FortisBC.

March 2006/March 2005 – Net earnings applicable to common shares were $36.6 million, or $0.35 per common share, for the first quarter of 2006 compared to earnings of $39.2 million, or $0.40 per common share, for the first quarter of 2005. Earnings for the first quarter of 2005 included the $7.9 million after-tax Ontario Settlement gain. Excluding the Ontario Settlement gain in 2005, earnings increased quarter over quarter primarily due to higher earnings at FortisBC and FortisAlberta, and increased non-regulated hydroelectric production in Belize. The increase in earnings was also due to an 11 per cent overall increase in electricity rates, effective July 1, 2005, and higher electricity sales at Belize Electricity. Partially offsetting the earnings increase was an anticipated decline in earnings at Newfoundland Power as a result of a change in the Company's revenue recognition policy, a decrease in equity income from Caribbean Utilities driven by higher fuel costs and the impact of lower average wholesale energy prices in Ontario. Earnings per common share for the first quarter of 2006 were impacted by the dilution created by the $130 million issue of common shares on March 1, 2005.

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO, together with management, have evaluated the effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2006 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for the design of internal controls over financial reporting within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design of the Corporation's internal controls over financial reporting as of December 31, 2006 and, based on that evaluation, have concluded that the design of these controls is effective to provide such reasonable assurance.

There has been no change in the Corporation's internal controls over financial reporting during the fourth quarter of 2006 that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

Recent Acquisitions

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all issued and outstanding shares of Fortis Turks and Caicos for aggregate consideration of approximately $97.7 million (US$87.8 million). On November 1, 2006, Fortis Properties, a wholly owned subsidiary of Fortis, purchased four hotels located in Alberta and British Columbia for aggregate consideration of approximately $52 million. Management of Fortis is assisting financial management of the acquired entities in developing systems of internal controls appropriate for operations of a subsidiary or division of a public company as these operations transition from private ownership. Fortis expects these systems of internal controls will be implemented during 2007. Management expects that the likelihood of a material misstatement occuring as a result of control weaknesses associated with these acquired entities' operations is low because of the nature and the relative size of those entities.

Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities on November 7, 2006 and now owns an approximate 54 per cent controlling interest in the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. The CEO and CFO of Caribbean Utilities have evaluated the effectiveness of disclosure controls and procedures and concluded, with reasonable assurance, that the disclosure controls and procedures of Caribbean Utilities were effective and adequate as of the Company's fiscal year ended April 30, 2006.

Subsequent Events

On January 3, 2007, FortisAlberta closed a $110 million senior unsecured debenture offering. The debentures bear interest at a rate of 4.99 per cent, to be paid semi-annually, and mature on January 3, 2047. The proceeds of the offering were used to repay existing indebtedness incurred under the Company's committed unsecured credit facility, which was incurred primarily to fund capital expenditures, and for general corporate purposes.

On January 18, 2007, Fortis issued 5,170,000 Common Shares for $29.00 per common share. The common share issue resulted in gross proceeds of $149.9 million, or approximately $145.6 million net of after-tax expenses. The net proceeds of the offering were used to repay indebtedness incurred for recent acquisitions, to support the capital expenditure programs of the Corporation's regulated utilities in Western Canada and for general corporate purposes.

On February 8, 2007, Fortis announced that its Board of Directors had declared a 10.5 per cent increase in the quarterly common share dividend, increasing the amount from 19 cents per common share to 21 cents per common share, commencing with the second quarter dividend payable on June 1, 2007, to shareholders of record on May 4, 2007.

On February 26, 2007, Fortis entered into an agreement (the "Acquisition Agreement") with 3211953 Nova Scotia Company and Kinder Morgan, Inc. ("Kinder Morgan") (NYSE:KMI), a U.S. energy transportation, storage and distribution company based in Houston, Texas, for the purchase (the "Acquisition") of all the issued and outstanding shares of Terasen Inc. for aggregate consideration of $3.7 billion, including the assumption of approximately $2.3 billion of consolidated indebtedness of Terasen Inc. Terasen Inc. is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business – natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen Inc. to divest itself of its petroleum transportation operations. The closing of the Acquisition, which is expected to occur in mid-2007, is subject to receipt of required regulatory and other approvals, including that of the BCUC, and the satisfaction of certain closing conditions. Under the Acquisition Agreement, Kinder Morgan or Fortis may elect to terminate the Acquisition Agreement if the Acquisition is not completed prior to November 30, 2007.

To finance a portion of the Acquisition, Fortis entered into an agreement on February 27, 2007 with CIBC World Markets Inc., Scotia Capital Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc., Canaccord Capital Corporation, Beacon Securities Limited and HSBC Securities (Canada) Inc. (collectively the "Underwriters") pursuant to which they agreed to purchase from Fortis and sell to the public 38,500,000 Subscription Receipts of the Corporation for a purchase price of $26.00 per Subscription Receipt. The Underwriters also had the option to purchase up to an additional 5,775,000 Subscription Receipts at the purchase price of $26.00 per Subscription Receipt to cover over-allotments, if any, at any time until 30 days following the closing of the Subscription Receipt offering. The gross proceeds from the sale of Subscription Receipts of $1,001,000,000 ($1,151,150,000 if the Over-Allotment Option is exercised in full) will be held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the Acquisition and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition (collectively, the "Release Conditions"). Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions, and without payment of additional consideration, one Common Share of Fortis and a cash payment equal to the dividends declared on Fortis Common Shares to holders of record during the period from the closing of the Subscription Receipt offering to the date of issuance of the Common Shares in respect of the Subscription Receipts. In the event that the Release Conditions are not satisfied by November 30, 2007, or if the Acquisition Agreement is terminated prior to such time, the holders of Subscription Receipts will be entitled to receive an amount equal to the full subscription price thereof plus their pro rata share of the interest earned or income generated on such amount. On March 15, 2007, the Subscription Receipt offering closed, the Underwriters exercised the Over-Allotment Option and therefore $1,151,150,000 was placed into escrow.

Fortis has also obtained a commitment from Canadian Imperial Bank of Commerce providing for an aggregate of $1.425 billion non-revolving term credit facilities in favour of Fortis to fund, if necessary, the full cash purchase price for the Acquisition. The net proceeds from the Subscription Receipt offering and funds to be advanced under the acquisition credit facilities will be used to finance the cash portion of the acquisition purchase price.

Outlook

The Corporation's business of regulated utilities is capital intensive and Fortis expects that most of its electric utility capital expenditures of more than $2.6 billion over the next five years will be driven by FortisAlberta and FortisBC. Gross consolidated utility capital expenditures for 2007, excluding Terasen, are expected to exceed $600 million, approximately $256 million and $139 million of which are expected to be invested in FortisAlberta and FortisBC, respectively. Capital expenditures related to income producing properties are expected to be approximately $13 million in 2007. Upward pressure on future capital expenditures may be experienced by FortisAlberta in response to expected continued robust economic growth in Alberta, driven by the expansion of the oil and gas industry in that province.

Organic earnings growth at Fortis will be driven by significant infrastructure investment at the regulated utilities in Western Canada and at the regulated and non-regulated utilities in the Caribbean.

Over the next several quarters the Corporation will focus on closing and integrating the Terasen Inc. acquisition. The addition of the natural gas distribution business will double the Corporation's investment in regulated rate base assets. Going forward, the Corporation will continue to pursue organic and acquisition growth opportunities in regulated gas and electric utility businesses in Canada, the Caribbean and the United States. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Outstanding Share Data

At March 15, 2007, the Corporation had issued and outstanding 109,422,397 Common Shares, 5,000,000 First Preference Shares, Series C; 7,993,500 First Preference Shares, Series E; 5,000,000 First Preference Shares, Series F; and 44,275,000 Subscription Receipts. As at December 31, 2006, the number of Common Shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E is described in the Notes to the 2006 Fortis Inc. Annual Consolidated Financial Statements.

Additional information, including the Fortis Inc. 2006 Annual Information Form and Management Information Circular, is available on SEDAR at www.sedar.com and on the Corporation's web site at www.fortisinc.com.

Management's Report

The accompanying Consolidated Financial Statements of Fortis Inc. and all information in the 2006 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2006 Annual Report is consistent with that in the Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee.

The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Consolidated Financial Statements and to review and report to the Board on policies relating to the accounting and financial reporting and disclosure processes. The Audit Committee has the duty to review financial reports requiring Board approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2006 Consolidated Financial Statements and Management Discussion and Analysis contained in the 2006 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2006 Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

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

St. John's, Canada

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2006 and 2005 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada,
January 26, 2007 (except for Note 29 (c) and (d), which are as at March 15, 2007)

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in thousands)

ASSETS	2006	2005 *(Note 3)*
Current assets		
Cash and cash equivalents	**$ 40,921**	$ 33,416
Accounts receivable	**278,114**	204,169
Income taxes receivable	**7,505**	–
Prepaid expenses	**14,255**	9,786
Regulatory assets *(Note 4)*	**35,669**	33,289
Materials and supplies	**32,675**	18,614
	409,139	299,274
Corporate income tax deposit *(Note 28 (a))*	**5,922**	–
Deferred charges and other assets *(Note 5)*	**174,835**	148,140
Regulatory assets *(Note 4)*	**132,991**	82,315
Future income taxes *(Note 21)*	**7,053**	58,815
Utility capital assets *(Note 6)*	**3,574,851**	2,900,393
Income producing properties *(Note 7)*	**468,984**	414,608
Investments *(Note 8)*	**2,536**	167,393
Intangibles, net of amortization *(Note 2)*	**9,819**	14,027
Goodwill *(Note 9)*	**661,311**	512,139
	$ 5,447,441	$ 4,597,104
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 10)*	**$ 97,669**	$ 48,868
Accounts payable and accrued charges	**333,755**	265,223
Dividends payable	**21,705**	17,924
Income taxes payable	**–**	22,785
Regulatory liabilities *(Note 4)*	**26,380**	19,392
Current instalments of long-term debt and capital lease obligations *(Note 11)*	**84,786**	31,392
Future income taxes *(Note 21)*	**959**	6,714
	565,254	412,298
Deferred credits *(Note 12)*	**78,987**	64,261
Regulatory liabilities *(Note 4)*	**338,901**	367,693
Future income taxes *(Note 21)*	**57,737**	44,718
Long-term debt and capital lease obligations *(Note 11)*	**2,558,463**	2,135,674
Non-controlling interest *(Note 13)*	**130,505**	39,555
Preference shares *(Note 14 (i) and (ii))*	**319,492**	319,492
	4,049,339	3,383,691
Shareholders' equity		
Common shares *(Note 15)*	**828,985**	813,304
Preference shares *(Note 14 (iii))*	**122,466**	–
Contributed surplus	**4,687**	3,179
Equity portion of convertible debentures *(Note 11)*	**7,175**	1,500
Foreign currency translation adjustment *(Note 17)*	**(51,508)**	(16,312)
Retained earnings	**486,297**	411,742
	1,398,102	1,213,413
	$ 5,447,441	$ 4,597,104

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

See accompanying Notes to consolidated financial statements

Approved on Behalf of the Board

Bruce Chafe,
Director

David G. Norris,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the Years Ended December 31 (in thousands, except per share amounts)

	2006	2005
Operating Revenues	**$ 1,461,998**	$ 1,430,005
Equity Income	**9,738**	11,466
	1,471,736	1,441,471
Expenses		
Energy supply costs	**540,485**	533,915
Operating	**398,587**	392,380
Amortization	**177,511**	157,622
	1,116,583	1,083,917
Operating Income	**355,153**	357,554
Finance charges *(Note 18)*	**168,329**	153,825
Gain on sale of income producing property *(Note 19)*	**(2,088)**	–
Gain on settlement of contractual matters *(Note 20)*	**–**	(10,000)
	166,241	143,825
Earnings Before Corporate Taxes	**188,912**	213,729
Corporate taxes *(Note 21)*	**32,538**	70,416
Net Earnings Before Non-Controlling Interest	**156,374**	143,313
Non-controlling interest	**7,602**	6,216
Net Earnings	**148,772**	137,097
Preference share dividends	**1,585**	–
Net Earnings Applicable to Common Shares	**$ 147,187**	$ 137,097
Weighted Average Common Shares Outstanding *(Note 15)*	**103,578**	101,750
Earnings Per Common Share *(Note 15)*		
Basic	**$ 1.42**	$ 1.35
Diluted	**$ 1.37**	$ 1.24

Consolidated Statements of Retained Earnings

FORTIS INC.

For the Years Ended December 31 (in thousands)

	2006	2005
Balance at Beginning of Year	**$ 411,742**	$ 337,013
Net Earnings Applicable to Common Shares	**147,187**	137,097
	558,929	474,110
Dividends on Common Shares	**(72,632)**	(62,368)
Balance at End of Year	**$ 486,297**	$ 411,742

See accompanying Notes to consolidated financial statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the Years Ended December 31 (in thousands)

	2006	2005
Operating Activities		
Net earnings	**$ 148,772**	$ 137,097
Items not Affecting Cash		
Amortization – capital assets, net of contributions in aid of construction	**166,954**	147,222
Amortization – intangibles	**4,208**	4,428
Amortization – other	**6,349**	5,972
Future income taxes *(Note 21)*	**10,257**	12,322
Accrued employee future benefits	**(2,738)**	1,915
Equity income, net of dividends	**(2,635)**	(3,426)
Stock-based compensation	**1,965**	1,569
Unrealized foreign exchange gain on long-term debt *(Note 18)*	**(1,725)**	(2,335)
Non-controlling interest	**7,602**	6,216
Gain on sale of income producing property *(Note 19)*	**(2,088)**	–
Other	**(681)**	1,653
Change in long-term regulatory assets and liabilities	**(30,594)**	(3,160)
Increase in corporate income tax deposit *(Note 28 (a))*	**(5,922)**	–
	299,724	309,473
Change in non-cash operating working capital	**(36,587)**	(5,888)
	263,137	303,585
Investing Activities		
Change in deferred charges and credits and other assets	**(25,028)**	(1,550)
Purchase of utility capital assets	**(483,103)**	(424,754)
Purchase of income producing properties	**(16,887)**	(21,275)
Contributions in aid of construction	**53,564**	45,130
Proceeds on sale of capital assets	**8,196**	1,556
Business acquisitions, net of cash acquired	**(168,931)**	(66,018)
Increase in investments	**(1,893)**	(193)
	(634,082)	(467,104)
Financing Activities		
Change in short-term borrowings	**37,557**	(132,818)
Proceeds from long-term debt	**468,823**	348,698
Repayment of long-term debt and capital lease obligations	**(197,270)**	(126,411)
Redemption of preference shares	**–**	(38)
Advances from (to) non-controlling interest	**9,535**	(596)
Issue of common shares	**15,224**	135,253
Issue of preference shares	**121,117**	–
Dividends		
Common shares	**(72,632)**	(62,368)
Preference shares	**(1,585)**	–
Subsidiary dividends paid to non-controlling interest	**(2,407)**	(1,803)
	378,362	159,917
Effect of exchange rate changes on cash	**88**	(185)
Change in Cash and Cash Equivalents	**7,505**	(3,787)
Cash and Cash Equivalents, Beginning of Year	**33,416**	37,203
Cash and Cash Equivalents, End of Year	**$ 40,921**	$ 33,416

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

See accompanying Notes to consolidated financial statements

December 31, 2006 and 2005

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally a diversified, international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation and commercial real estate and hotels, which are treated as two separate segments. The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary briefly describes the operations included in each of the Corporation's operating and reportable segments.

Regulated Utilities – Canadian

The following summary describes the Corporation's interests in Regulated Utilities in Canada by utility:

(a) *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 430,000 customers.

(b) *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia serving more than 152,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 235 megawatts ("MW"). Included with the FortisBC component of the Regulated Utilities – Canadian segment are the non-regulated operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC's assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited ("PLP"). PLP was purchased by Fortis through an indirect subsidiary on May 31, 2005. Effective January 1, 2007, PLP was amalgamated with FortisBC Inc. as part of an internal corporate reorganization.

(c) *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 230,000 customers. Newfoundland Power has an installed generating capacity of 136 MW, of which 92 MW is hydroelectric generation.

(d) *Maritime Electric:* Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 71,000 customers. Maritime Electric also maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined capacity of 150 MW.

(e) *FortisOntario:* FortisOntario provides an integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement entered into in April 2002. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electrical distribution companies formed in 2000 serving more than 27,000 customers.

Regulated Utilities – Caribbean

The following summary describes the Corporation's interest in Regulated Utilities in the Caribbean by utility:

(a) *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving more than 71,000 customers. The Company has an installed generating capacity of 37 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity (December 31, 2005 – 68.5 per cent).

(b) *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 22,000 customers. The Company has an installed generating capacity of 120 MW. On November 7, 2006, Fortis acquired an additional 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities' balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis will consolidate Caribbean Utilities' financial statements on a two-month lag basis and will include Caribbean Utilities' January 31, 2007 balance sheet and statements of earnings and cash flows for the three-month period ended January 31, 2007. During 2006 and 2005, the statements of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on a two-month equity lag basis.

(c) *P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") (collectively referred to as "Fortis Turks and Caicos")*: Fortis Turks and Caicos was acquired on August 28, 2006 by Fortis through a wholly owned subsidiary. Fortis Turks and Caicos serves approximately 7,700 customers, or 80 per cent of electricity customers, in the Turks and Caicos Islands and has an installed diesel-fired generating capacity of approximately 37 MW. The Company is the principal distributor of electricity in the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Non-Regulated – Fortis Generation

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

(a) *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.

(b) *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement ("NEA"), a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.

(c) *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through a wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric plants in central Newfoundland. Upon the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties now directly holds the 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. Previously, the 51 per cent interest was held by CNE Energy Inc. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033.

(d) *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership ("WPP"), a wholly owned partnership of FortisBC Inc.

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 18 hotels with more than 3,200 rooms in seven Canadian provinces and 2.7 million square feet of commercial real estate in Atlantic Canada. Included are the four hotels in Alberta and British Columbia acquired by Fortis Properties on November 1, 2006.

Corporate

The Corporate segment captures expense and revenue items not specifically related to any operating segment. Included in the Corporate segment are finance charges, including interest on debt incurred directly by Fortis and dividends on preference shares classified as long-term liabilities, foreign exchange gains or losses, dividends on preference shares classified as equity, other corporate expenses net of recoveries from subsidiaries, interest and miscellaneous revenues, and corporate income taxes.

2. Summary of Significant Accounting Policies

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. These differences are described in Note 2, under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

December 31, 2006 and 2005

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

Regulation

FortisAlberta

FortisAlberta is regulated by the Alberta Energy Utilities Board ("AEUB"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AEUB administers these acts and regulations covering such matters as tariffs, rates, construction, operations and financing. FortisAlberta operates under cost of service regulation as prescribed by the AEUB. Rate orders issued by the AEUB establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business, and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed rate of return on common equity ("ROE") was 8.93 per cent for 2006 (2005 – 9.50 per cent). FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisBC

FortisBC is regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. FortisBC operates primarily under cost of service regulation as prescribed by the BCUC. The Company applies to the BCUC for annual revenue requirements based on estimated cost of service, including, but not limited to, operating expenses, power purchases, depreciation and amortization, property taxes, income taxes, interest on debt and an allowed ROE. FortisBC's allowed ROE was 9.20 per cent for 2006 (2005 – 9.43 per cent). FortisBC's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. In addition, the regulatory framework includes some performance-based rate-setting ("PBR") attributes. PBR is subject to change as the Company's regulatory framework evolves.

Newfoundland Power

Newfoundland Power operates under cost of service regulation as administered by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issue of securities of Newfoundland Power. The *Public Utilities Act* (Newfoundland and Labrador) also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The determination of the forecast rate of return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined through a general rate application. In between general rate applications, customer rates are adjusted annually through the operation of an automatic adjustment formula that sets an appropriate annual rate of return on rate base based on the forecast cost of common equity and adjusts for changes in observed long-term Canada bond yields. The allowed ROE reflected in customer rates for 2006 was 9.24 per cent (2005 – 9.24 per cent).

Maritime Electric

In December 2003, the Government of Prince Edward Island proclaimed legislation returning Maritime Electric to traditional cost of service regulation. Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island), effective January 1, 2004. On January 1, 2004, the *Maritime Electric Company Limited Regulation Act* was repealed. Under the new regulatory model, Maritime Electric's basic rates, as set by rate orders by IRAC, are now based on actual costs and provide an approved rate of return on approved rate base assets. Maritime Electric's allowed ROE was 10.25 per cent for 2006 (2005 – 10.25 per cent). Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment. The *Electric Power Act* (Prince Edward Island) provides for an orderly transition from the previous regulatory model and allows the Company to collect the $20.8 million in Costs Recoverable From Customers deferred as at December 31, 2003 under terms and conditions to be set out by IRAC. IRAC has allowed Maritime Electric to collect $1.5 million, $2.5 million and $1.5 million of these recoverable costs in fiscal years 2004, 2005 and 2006, respectively.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost of service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. On April 28, 2006, the OEB issued its Decision and Order concerning Canadian Niagara Power's application for new electricity rates, effective May 1, 2006. The new distribution electricity rates were based on 2004 costs using a deemed capital structure at 50 per cent long-term debt and 50 per cent common equity, with an allowed ROE of 9.0 per cent. The Decision and Order also approved the final recovery from customers of regulatory assets including the transitional costs incurred in preparation for the open market in May 2002. Cornwall Electric is exempt from many aspects of these Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, dated July 31, 1998. The rate-setting mechanism is subject to price cap with commodity cost flow-through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The primary duty of the PUC is to ensure that the services rendered by the Company are satisfactory and that the charges imposed in respect of those services are fair and reasonable. The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. Basic electricity rates for Belize Electricity are comprised of two components. The first component is Value-Added Delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow-through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization and rate of return on regulated asset base in the range of 10 per cent to 15 per cent. The VAD component of the tariff is normally reviewed every four years, while the COP component and any rate stabilization account ("RSA") recovery are reviewed at each annual rate proceeding and at Threshold Event Review Proceedings, which can occur at any time when deferrals of COP into the RSA exceed $1.7 million (BZ$3.0 million).

Caribbean Utilities

Caribbean Utilities generates and distributes electricity in its exclusive licence area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government") originally dated May 10, 1966, amended November 1, 1979 and renewed for a further 25 years on January 17, 1986 (collectively, the "Licence"). The Licence allows for subscribers' tariffs to be adjusted annually to provide Caribbean Utilities with a rate of return of 15 per cent on capital employed, as defined in the Licence. The 15 per cent rate of return is for the fixed term of the Licence and does not take into consideration actual interest charges, unless they are in excess of 15 per cent per annum, and costs of capital incurred by Caribbean Utilities. Additionally, the Licence provides for monthly adjustments to be made to the rates billed to consumers to reflect variations in the cost to Caribbean Utilities of diesel fuel used in the generation of electricity.

In January 2006, the Government exercised its right under the current Licence to increase the duty rate paid by Caribbean Utilities on foreign purchases from 10 per cent to 15 per cent. Under the terms of the Licence, customs duties are included in the rate base for capital expenditures and allowable operating expenditures in determining earnings.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands in order to provide Fortis Turks and Caicos with a return of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfalls. The submissions for 2006 calculated the Allowable Operating Profit for 2006 to be $11.0 million and $0.2 million (US$9.5 million and US$0.1 million) and the cumulative shortfalls at December 31, 2006 to be $2.9 million and $1.3 million (US$2.5 million and US$1.2 million) for PPC and Atlantic, respectively. The companies have a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

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

Materials and Supplies

Materials and supplies are valued at the lower of average cost and market value, determined on the basis of estimated net realizable value.

December 31, 2006 and 2005

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

Deferred Charges and Credits and Other Assets

Deferred charges and credits and other assets include deferred pension costs, accrued pension obligations, unamortized debt discounts and deferred financing expenses, Alberta Electric System Operator ("AESO") contributions, deferred recoverable and project costs, energy management loans, an investment held at Fortis Properties as collateral for a loan, customer deposits, and other deferred charges and credits. Debt discounts and deferred financing expenses are amortized on a straight-line basis over the term of the related debt. AESO contributions represent payments to the AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through AEUB-approved amortization rates. Prior to 2006, AESO contributions were included with the AESO charges deferral regulatory asset or liability. Deferred recoverable project costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties. Energy management loans range in terms from one year to five years and are deferred until they are recovered from customers. Other deferred charges and credits are recorded at cost and are amortized over the estimated period of future benefit.

Deferred charges and credits also include deferred gains and losses on the cancellation of swap contracts. In December 2003, Fortis entered into a forward interest rate swap agreement that swapped 90-day bankers' acceptance interest rate payments on $200 million of long-term debt to 5.6 per cent. In October 2004, upon the completion of the long-term acquisition financing for FortisAlberta and FortisBC, the forward interest rate swap agreement was terminated and a cash payment of $14.1 million made upon termination of the swap is being amortized on a straight-line basis over 10 years, the term of the related financing.

In October 2004, Fortis cancelled its US dollar currency swap agreement, under which the interest payments on the Corporation's $100 million Senior Unsecured Debentures were converted into US dollar interest payments. The cancellation of the US dollar currency swap agreement resulted in a gain of $4.7 million, which is being amortized on a straight-line basis over the remaining term of the $100 million Senior Unsecured Debentures, which mature in October 2010.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US two dollars, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent the cost of utility capital assets contributed by customers and governments. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2006, the long-term regulatory liability for future removal and site restoration costs was $306.5 million (December 31, 2005 – $280.9 million) (Note 4 *(xix)*). FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record removal and site restoration costs in earnings when incurred and these costs did not have a material impact on the Corporation's 2006 and 2005 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by the respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer electricity rates. At FortisOntario, Caribbean Utilities and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets, is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2006 was approximately $22.1 million (2005 – $27.3 million).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

As required by their respective regulators, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets, but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2006, GEC totalled $18.2 million (2005 – $11.8 million).

FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by their respective regulators, include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges, and AFUDC capitalized during 2006 was $4.4 million (2005 – $6.7 million) (Note 18), including an equity component of $1.8 million (2005 – $3.3 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for depreciation and amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2006, amortization expense was reduced by $4.8 million (2005 – $5.0 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 1.4 per cent to 24.2 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2006 was 4.2 per cent (2005 – 4.0 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission and generation assets as at December 31st were as follows.

	As at December 31st			
	2006		2005	
	Service Life Ranges (Years)	**Average Remaining Service Life (Years)**	**Service Life Ranges (Years)**	**Average Remaining Service Life (Years)**
Distribution	**10-75**	**27**	10-75	27
Transmission	**10-75**	**30**	10-75	31
Generation	**5-75**	**31**	10-75	36

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate, except where a write-down is required to reflect a permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of two years to 20 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Intangibles

Intangibles represent the estimated fair value of water rights associated with the Rankine Generating Station in Ontario. As at December 31, 2006, the net book value of intangibles was $9.8 million (net of accumulated amortization of $15.1 million) [2005 – $14.0 million (net of accumulated amortization of $10.9 million)]. The water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. Effective May 1, 2009, in accordance with the NEA, FortisOntario's water entitlement on the Niagara River associated with the Rankine Generating Station will not be renewed.

The Corporation evaluates the carrying value of intangibles for potential impairment through ongoing review and analysis of fair market value and expected earnings. Should an impairment in the value of intangibles be identified, it will be recorded in the period such impairment is recognized.

December 31, 2006 and 2005

Asset Impairment

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives, deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period it is identified. There was no impact on the financial statements as a result of asset impairments for the year ended December 31, 2006.

During 2005, the remaining value of the Rankine Generating Station assets, located on the Niagara River, was written down as a result of the implementation of the NEA. The NEA assigns FortisOntario's water rights on the Niagara River to Ontario Power Generation Inc. ("OPGI") and facilitates the irrevocable exchange of 75 MW of wholesale electric power supply to FortisOntario Inc. from OPGI until April 30, 2009 in exchange for FortisOntario Inc.'s agreement not to seek renewal of the water entitlement at that time. The write-down totalled $1.7 million ($1.1 million after tax) in 2005.

The process for asset impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the economic value of the generating facility. Asset impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's economic value, including a fair return on capital, is provided through customer electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset specific but are pooled for the entire regulated enterprise.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment.

The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the year ended December 31, 2006 (2005 – nil).

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. With the exception of Newfoundland Power, pension plan assets are valued at fair value. At Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time. At FortisAlberta, as approved by the AEUB, the cost of the defined benefit and defined contribution pension plans is being recovered in customer rates based on employer cash contributions made into the defined benefit pension plan, while the cost of the defined contribution pension plan is being recovered based on the filed amount of the funding requirements.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered or refunded in future customer rates, is subject to deferral treatment (Note 4 *(xviii)*).

Other Post-Employment Benefits

The Corporation, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans including certain health and dental coverage for qualifying members. Additionally, the Corporation, FortisAlberta, Newfoundland Power and Maritime Electric provide for retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with these other post-employment benefit plans are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets, at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

In 2006, FortisAlberta, as approved by the AEUB, recovered in customer rates the costs of other post-employment benefit and supplemental pension plans based on the cash payments made. In 2005, FortisAlberta, as approved by the AEUB, recovered in customer rates the costs of other post-employment benefit and supplemental pension plans based on the accrual method of accounting. The change in how other post-employment benefits and supplemental pension plan costs are recovered in customer rates had no impact on the Corporation's earnings in 2006.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for other post-employment benefit and supplemental pension plans, which is expected to be recovered or refunded in future customer rates, is subject to deferral treatment (Note 4 *(viii)*).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options under its 2002 Stock Option Plan. Beginning in 2007, all new stock options will be granted under the Corporation's 2006 Stock Option Plan (Note 16). Compensation expense is measured at the date of grant using the Black Scholes fair value option pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option price and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

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

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining, are translated at the exchange rate in effect at the balance sheet dates. The exchange rate in effect at December 31, 2006 was US$1.00 = CDN$1.17 (December 31, 2005 – US$1.00 = CDN$1.16). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity as a foreign currency translation adjustment. Revenue and expense items are translated at the average exchange rate in effect during the period.

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in the statement of earnings.

Foreign exchange translation gains and losses on foreign currency denominated long-term debt that is designated as a hedge of foreign net investments are recorded as foreign currency translation adjustments in shareholders' equity.

Hedging Relationships

At December 31, 2006, the Corporation's hedging relationships consisted of interest-rate swap contracts and US dollar borrowings. Derivative instruments, such as interest rate swap contracts, are used only to manage risk and are not used for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet and assesses, both at the hedge's inception and on an ongoing basis, whether the hedging transactions are effective in offsetting changes in cash flows of the hedged items. Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item. If a derivative instrument is terminated

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

or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in earnings concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in earnings. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in earnings. The change in the market value of the interest rate swap contracts, which fluctuates over time, is not recognized until interest payments are made.

The Corporation's foreign net investments are exposed to changes in the US dollar exchange rate and the Corporation has reduced its exposure to foreign currency exchange rate fluctuations on a substantial portion of its foreign net investments through the use of US dollar borrowings. As at December 31, 2006, all of the Corporation's US$258.6 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2006, the Corporation had approximately US$121 million in foreign net investments available to be hedged.

Income Taxes

Except as described below for FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense is recognized for the estimated income taxes payable in the current year.

Effective January 1, 2006, FortisAlberta is following the taxes payable method of accounting for federal income taxes. As prescribed by the 2006/2007 Negotiated Settlement Agreement, approved by the AEUB on June 29, 2006, corporate income tax expenses are now recovered through customer rates based only on income taxes that are currently payable for regulatory purposes. Under the new methodology, current rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. Accordingly, FortisAlberta no longer recognizes income taxes deferred to future years as a result of the specified temporary differences. The Company only recognizes future income taxes for certain deferral amounts where the future income taxes will not be collected in future customer rates.

In 2005, FortisAlberta followed the taxes payable method of accounting only for provincial income taxes because federal income tax expenses were recovered through customer rates based on a modified liability method. Under the modified liability method, customer rates included the recovery of future federal income taxes related to specified temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes. As a result, FortisAlberta previously recognized future federal income taxes and set up a regulatory liability equal to the amount of future federal income taxes recognized that had not yet been reflected in customer rates. However, due to the AEUB-approved 2006/2007 Negotiated Settlement Agreement, the future income tax asset and offsetting regulatory liability were no longer recognized, which resulted in a $50.7 million reduction in the Corporation's future income tax assets and regulatory liabilities during the second quarter of 2006. Had FortisAlberta accounted for its regulated operations using the liability method in 2006, the Corporation would have recognized additional future income tax expense of approximately $17.7 million for the year ended December 31, 2006 (Note 21); however, there would have been no earnings impact associated with the additional future income tax expense as FortisAlberta would have recorded an offsetting regulatory asset for future recovery in customer rates.

As ordered by the BCUC, FortisBC follows the taxes payable method of accounting for income taxes on regulated earnings. Therefore, customer rates do not include the recovery of future income taxes related to temporary differences between the tax basis of regulated assets and liabilities and their carrying amounts for accounting purposes.

The PUB specifies Newfoundland Power's method of accounting for income taxes. Effective January 1, 1981, pursuant to PUB order, future income tax liabilities at Newfoundland Power are recognized solely on temporary differences in capital cost allowance in excess of amortization of capital assets, excluding GEC. Current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, but these taxes are expected to be collected in future customer rates when the taxes become payable.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. If this method was applied at FortisAlberta, FortisBC and Newfoundland Power, future income tax liabilities and future income tax assets would have increased by approximately $121.8 million and $56.3 million, respectively, at December 31, 2006 (December 31, 2005 – $126.2 million and $29.0 million, respectively).

Belize Electricity is subject to income tax; however, effective March 1, 2005, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario. Transmission is the conveyance of electricity at high voltages (generally at voltage levels of 69 kilovolts ("kV") and above) and distribution is the conveyance of electricity at lower voltages (generally at voltage levels below 69 kV). Distribution networks convey electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of electricity by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically, usually monthly, and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end.

Prior to January 1, 2006, as required by the PUB, revenue derived from electricity sales at Newfoundland Power was recognized as bills were rendered to customers. The difference between revenue recognized on a billed basis versus an accrual basis ("unbilled revenue") was deferred and reported on the balance sheet as a regulatory liability (Note 4 *(xx)*). Effective January 1, 2006, Newfoundland Power received approval from the PUB to change its revenue recognition policy for financial and regulatory reporting purposes from a billed basis to an accrual basis. The transition to recording revenue on an accrual basis had no material impact on Newfoundland Power's 2006 annual earnings. In conjunction with this change in accounting policy, a portion of the unbilled revenue as of December 31, 2005 will be recognized as revenue in future periods, as approved by the PUB. The Company received PUB approval to recognize $3.1 million as revenue in 2006 and $2.7 million as revenue in 2007, to offset the income tax impact associated with the transition to the accrual basis of revenue recognition for income tax purposes in these years. Disposition of the remaining regulatory liability has been deferred until the Company's next general rate application, which is currently anticipated to be filed in 2007 for the purpose of setting electricity rates for 2008.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 *(xx)*).

FortisAlberta reports revenues and expenses related to transmission services on a net basis in other revenue. At the Corporation's other regulated utilities, transmission revenues and expenses are recorded on a gross basis. As stipulated by the AEUB, FortisAlberta is required to arrange and pay for transmission service with AESO and collect transmission revenue from its customers, which is done through invoicing the customers' retailers through FortisAlberta's transmission component of its AEUB-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the pass-through of transmission costs to end-use customers as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected or refunded in future customer rates.

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow-through to customers and these costs, and revenue associated with the recovery of these costs, are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generating operations record revenue on an accrual basis, and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generating stations is metered at or very near month end and production data is used to record revenue earned.

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

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue.

The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset Retirement Obligations

Asset retirement obligations are recorded as a liability at fair value, with a corresponding increase to utility capital assets and income producing properties. The Corporation recognizes asset retirement obligations in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

The Corporation has asset retirement obligations associated with hydroelectric generating facilities and with interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal asset retirement obligations, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified to date in respect of the Corporation's hydroelectric generating facilities. These facilities are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and to ensure the continued provision of electricity service to customers. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits or agreements are terminated, asset retirement obligations will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has asset retirement obligations associated with the removal of certain distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of removal costs cannot be reasonably determined at this time.

The Corporation has determined that an asset retirement obligation exists regarding the remediation of leased land on which a pumphouse is currently situated at Maritime Electric. The pumphouse is integral to the Company's operations and it is reasonably expected that the land lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. An asset retirement obligation associated with land remediation will be recorded when the lease is terminated at the request of the lessor and the costs are reasonably estimable.

On April 1, 2006, Fortis retroactively adopted Emerging Issues Committee Abstract EIC 159, Conditional Asset Retirement Obligations ("EIC 159"). EIC 159 requires an entity to recognize a liability for the fair value of an asset retirement obligation even though the timing and/or method of settlement are conditional on future events. While conditional asset retirement obligations have been identified, no amounts have been recorded as they are immaterial to the Corporation's results of operations and financial position.

Variable Interest Entities

Effective January 1, 2005, the Corporation adopted the recommendations of Accounting Guideline 15 ("AcG-15") on accounting for variable interest entities. The Corporation performed a review of its business arrangements with other entities and concluded that the entities do not require consolidation and that no variable interests are required to be disclosed under the requirements of AcG-15. There was no impact, therefore, to the financial statements upon the adoption of AcG-15.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Change in Presentation

Prior to December 31, 2006, the regulatory provision at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric for future removal and site restoration costs was part of amortization expense and was recorded in accumulated amortization, as these costs were recoverable in amortization rates from customers. Actual costs of removal and site restoration incurred, net of salvage proceeds, were recorded against this provision in accumulated amortization. In accordance with Canadian GAAP, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record removal and site restoration costs in earnings as incurred. In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric would be recognized as incurred rather than over the life of the asset through amortization expense. The Corporation has changed the presentation of the provision for future removal and site restoration as a regulatory liability rather than including it with accumulated amortization. This change in presentation has been applied retroactively, with restatement of 2005 comparative balances, and has had no impact on earnings. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a corresponding $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets resulting from a decrease in accumulated amortization (Note 4 *(xix)*).

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval. Based on previous, existing or expected future regulatory orders or decisions, the Corporation has recorded the following amounts expected to be recovered by or refunded to customers in future periods.

Regulatory Assets *(in thousands)*	**2006**	2005	**Remaining recovery period (Years)**
AESO charges deferral *(i)*	**$ 12,524**	$ 11,778	
Municipal tax asset *(ii)*	**7,239**	6,879	
Cost of Power and Hurricane Cost Rate Stabilization Accounts *(iii)*	**5,216**	5,004	
Rate stabilization account *(iv)*	**3,554**	2,405	
Deferred fuel costs *(v)*	**1,485**	–	
Energy cost adjustment mechanism (pre 2004) *(vi)*	**1,300**	1,500	
Commodity cost deferral *(vii)*	**–**	2,225	
Other *(xiv)*	**4,351**	3,498	
Current regulatory assets	**$ 35,669**	$ 33,289	1
Regulatory other post-employment benefit asset *(viii)*	**$ 36,416**	$ 29,401	Not determinable
AESO charges deferral *(i)*	**27,044**	–	2
Energy cost adjustment mechanism (pre 2004) *(vi)*	**13,984**	15,284	8
Deferred fuel costs *(v)*	**12,387**	–	Not determinable
Weather normalization account *(ix)*	**11,809**	10,100	Not determinable
Energy management costs *(x)*	**6,008**	5,413	8
Cost of Power and Hurricane Cost Rate Stabilization Accounts *(iii)*	**5,903**	11,979	Not determinable
Regulatory deferred capital asset amortization *(xi)*	**5,793**	–	Not determinable
Lease costs *(xii)*	**4,403**	3,786	17-29
Capital charge – Point Lepreau Station *(xiii)*	**2,708**	2,801	Not determinable
Commodity cost deferral *(vii)*	**2,298**	–	2
Other *(xiv)*	**4,238**	3,551	Various
Long-term regulatory assets	**$ 132,991**	$ 82,315	

December 31, 2006 and 2005

4. Regulatory Assets and Liabilities (cont'd)

Regulatory Liabilities *(in thousands)*	**2006**	2005	**Remaining settlement period (Years)**
Municipal tax liability *(ii)*	**$ 11,328**	$ 10,966	
Revenue deferral for 2006 rate reduction *(xv)*	**4,200**	–	
Regulatory future income tax liability *(xvi)*	**3,100**	900	
Energy cost adjustment mechanism (post 2003) *(vi)*	**2,991**	3,343	
Regulatory incentives *(xvii)*	**2,502**	469	
Regulatory pension deferral *(xviii)*	**–**	524	
Other *(xxi)*	**2,259**	3,190	
Current regulatory liabilities	**$ 26,380**	$ 19,392	1
Regulatory future removal and site restoration provision *(xix)*	**$ 306,467**	$ 280,913	Not determinable
Regulatory future income tax liability *(xvi)*	**–**	52,899	–
Unbilled revenue liability *(xx)*	**24,579**	27,760	Not determinable
Regulatory pension deferral *(xviii)*	**4,429**	5,065	7
Other *(xxi)*	**3,426**	1,056	Various
Long-term regulatory liabilities	**$ 338,901**	$ 367,693	

(i) *AESO Charges Deferral*

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral. It also includes deferrals for contributions paid to the AESO for investment in transmission facilities up to December 31, 2005, and certain riders and other miscellaneous charges related to the period from 2004 through 2006. To the extent that actual costs incurred exceeded the amount collected in revenue, the excess costs have been deferred as a regulatory asset and will be recognized when collected in future customer rates. In the event that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability. The liability will either be refunded to customers through a reduction in future rates or will be recognized when additional costs are incurred. The 2005 AESO charges deferral, which includes the carry forward of the 2004 AESO charges deferral balance, was approved by the AEUB in the amount of approximately $12.9 million. This balance, which includes an estimate for 2007 carrying costs of approximately $0.4 million, will be collected from customers through a 2007 transmission adjustment rider. The filing for the 2006 AESO charges deferral will not be made until 2007. Once approved, the 2007 deferral is expected to be collected in rates through a transmission adjustment rider, at which time these deferred costs will be recognized. In the absence of rate regulation, FortisAlberta would have recognized $27.8 million less in other revenue during 2006 (2005 – $13.4 million).

(ii) *Municipal Tax Asset and Liability*

At Newfoundland Power, as allowed by the PUB, a predetermined percentage of current-year electricity revenue is accrued to cover the following year's business and property taxes, as collectible from customers and payable to municipalities. The asset, net of amounts already collected from customers in the current year, is classified as a current regulatory asset. The liability of $11.3 million at December 31, 2006 (2005 – $11.0 million) is classified as a current regulatory liability. In the absence of rate regulation, these balances would be reversed with no earnings impact.

(iii) *Cost of Power and Hurricane Cost Rate Stabilization Accounts*

The PUC has allowed Belize Electricity to defer fuel costs, power purchases and diesel operating and maintenance expenses that are different from those amounts included in electricity rates when the rates were last set. These deferrals will be recovered from or rebated to customers. The Cost of Power Rate Stabilization Account ("CPRSA") was established to regulate the manner in which these differences in costs are recovered from or rebated to customers. Similarly, the PUC has allowed a Hurricane Cost Rate Stabilization Account ("HCRSA") to regulate the manner in which expenses associated with hurricane damage and recovery are recovered from customers. The rate of recovery or rebate is recalculated on July 1st of each year based on the balance in the CPRSA and HCRSA as of the preceding year end, but may be adjusted at any time as a result of reaching a certain threshold level. A $1.7 million (BZ$3.0 million) threshold level was established for the CPRSA, with effect from July 1, 2005, that allows for adjustments to the tariff once new deferrals to the CPRSA reach this level. Adjustments to the tariff as a result of reaching the threshold level may include adjustments to the COP component of the tariff and additional CPRSA recovery surcharges. In the absence of rate regulation, cost of power and hurricane costs would be expensed in the period incurred. During 2006, $1.0 million (BZ$1.8 million) of reductions in cost of power, interest and hurricane costs were deferred as compared to the deferral of excess costs of $15.7 million (BZ$26.0 million) during 2005. During 2006, $4.9 million (BZ$8.3 million) of previously deferred cost of power and hurricane costs was recovered through customer rates compared to $6.4 million (BZ$10.6 million) recovered during 2005.

The PUC regulates the recovery of the balance in the CPRSA and HCRSA. The outstanding balances at July 1, 2005 were approved for full recovery by June 30, 2009. In October 2005, excess deferrals into the CPRSA reached a threshold level and, on December 20, 2005, Belize Electricity filed an application with the PUC for a tariff adjustment to recover the excess deferrals and to increase the COP component of rates. The PUC subsequently approved a 13 per cent increase in average tariffs, effective January 1, 2006. The PUC will address subsequent balances in future annual rate submissions or threshold events, and recovery will be dependent on future operational circumstances that cannot be determined at this time.

(iv) *Rate Stabilization Account*

Newfoundland Power has a rate stabilization account that passes through to customers charges or reductions related to changes in the cost and quantity of fuel burned by Newfoundland Hydro to produce the electricity sold to the Company. Operation of this account has no earnings impact on Newfoundland Power. On July 1st of each year, the rate charged to Newfoundland Power's customers is recalculated in order to amortize, over the subsequent 12 months, the balance in the rate stabilization account as of December 31st of the previous year. In the absence of rate regulation, these charges would be accounted for in a similar manner; however, the amount recovered, or refunded, and the recovery, or refund, period would not be subject to regulatory approval. This regulatory asset is not subject to a regulatory return.

(v) *Deferred Fuel Costs*

Pursuant to the terms of their respective licences, Caribbean Utilities and Fortis Turks and Caicos are entitled to recover from customers any increase in the cost of fuel over a base amount, as defined in the licence agreements. The costs are recovered in the form of a surcharge on customer bills. Costs incurred and not yet recovered from customers are deferred as regulatory assets. In the absence of rate regulation, these costs would be expensed in the period incurred and energy supply costs at Fortis Turks and Caicos, from the date of acquisition by Fortis, would have been $2.0 million lower in 2006 and energy supply costs at Caribbean Utilities would have been $0.9 million higher.

(vi) *Energy Cost Adjustment Mechanism ("ECAM")*

Until December 31, 2003, Maritime Electric maintained an ECAM account to adjust for and recover from or return to customers the effect of variations in energy costs above or below 5 cents per kilowatt hour ("kWh"). Maritime Electric also maintained a cost of capital adjustment account to adjust earnings based on a target rate of return on average common equity. In the absence of rate regulation, these items would be recorded in the period incurred. Under the new legislation effective January 1, 2004, IRAC issued a regulatory order that allowed Maritime Electric to amortize to earnings $1.5 million of these pre-2004 recoverable costs in 2006 (2005 – $2.5 million). During 2006, IRAC issued a regulatory order approving the amortization of $1.3 million of these pre-2004 recoverable costs in 2007 and $2.0 million in 2008 and each year thereafter until the amount is collected. In the absence of rate regulation, revenue would have been $1.5 million higher in 2006 (2005 – $2.5 million).

Beginning in 2004, IRAC authorized the recovery from or return to customers of energy costs above or below an approved amount of 6.73 cents per kWh, over a rolling 18-month period, under the operation of a new ECAM. In 2006, IRAC ordered the continuation of the interim and transitional ECAM currently in effect, with the amortization period contained in the ECAM to decrease from 18 months to 12 months, effective January 1, 2007. The amounts removed from the ECAM account will be recoverable through basic customer rates. In the absence of rate regulation, energy supply costs would be expensed in the period incurred and would have been $3.1 million lower in 2006 (2005 – $5.7 million), and revenue would have been $3.5 million lower in 2006 (2005 – $0.4 million higher).

(vii) *Commodity Cost Deferral*

The commodity cost deferral represents the remaining balance of the commodity costs incurred in 2000 by FortisAlberta's former retail operations in excess of amounts recovered from customers. These commodity cost deferrals were collected from customers during the period from 2001 through 2003. In 2004, the AEUB approved the collection of additional recoverable costs from customers. As directed by the AEUB, FortisAlberta is expecting to submit an application in the first quarter of 2007 to collect the remaining balance of the deferred costs from customers by way of a rate rider. In the absence of rate regulation, FortisAlberta would have recognized these costs in the years incurred and no amount would be recorded on the balance sheet. The remaining deferred costs will be recognized when they are collected in rates. In the absence of rate regulation, revenue would have been $0.1 million lower in 2006 (2005 – $0.1 million).

4. Regulatory Assets and Liabilities (cont'd)

(viii) Regulatory Other Post-Employment Benefit ("OPEB") Asset

At FortisAlberta and Newfoundland Power and, prior to 2005 at FortisBC, the cash cost of providing OPEBs was collected in customer rates as permitted by the regulators. For 2005 and 2006, as permitted by the BCUC, the recovery from customers of the cost of OPEBs at FortisBC was based on cash costs plus a partial recovery of the full accrual cost of OPEBs. In 2005, as permitted by the AEUB, the recovery from customers of the cost of OPEBs at FortisAlberta was based on the accrual method of accounting. Effective January 1, 2006, as prescribed by the AEUB-approved 2006/2007 Negotiated Settlement Agreement, FortisAlberta is recovering from customers OPEB and supplemental pension plan costs based on the cash payments made.

The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. Upon recovery in customer rates, these deferred expenses will be recognized in earnings. In the absence of rate regulation, operating expenses in 2006 would have been $7.0 million (2005 – $6.0 million) higher as the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. This regulatory asset is not subject to a regulatory return.

Newfoundland Power is required to file a report with the PUB no later than its next general rate application that addresses the potential use of the accrual method as an alternative to the currently approved method of expensing the costs of OPEBs in the year paid.

(ix) Weather Normalization Account

The PUB has ordered provision of a weather normalization account for Newfoundland Power to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The methodology of this account anticipates that these variations will correct themselves over time. In the absence of rate regulation, these fluctuations would be recorded in earnings in the period in which they occurred.

As part of Newfoundland Power's 2003 general rate application, it was determined that $5.6 million of the balance of this account was not expected to reduce over time. This non-reversing portion of the balance is being amortized and recovered through rates on a straight-line basis over a five-year period ending in 2007. This amortization increases purchased power expenses by approximately $1.7 million per year and decreases income tax expense by approximately $0.6 million per year, for a net reduction of the non-reversing portion of the account balance of approximately $1.1 million per year.

Excluding the non-reversing portion, the remaining recovery period of the weather normalization account is not determinable, as it depends on weather conditions in the future. In the absence of rate regulation, revenue and energy supply costs in 2006 would have been $16.5 million (2005 – $10.6 million) lower and $13.3 million (2005 – $11.2 million) lower, respectively.

(x) Energy Management Costs

FortisBC provides energy management services to promote energy-efficiency programs to its customers. As required by a BCUC order, the Company has capitalized all related expenditures (except certain defined costs) and is amortizing these expenditures on a straight-line basis at 12.5 per cent per annum. This regulatory asset represents the unamortized balance of the energy management costs. The unamortized energy management costs are expected to be recovered from customers in rates over an average of eight years, based on the terms of the currently approved BCUC order. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred, which would have resulted during 2006 in increased operating expenses of $2.2 million (2005 – $2.4 million), decreased amortization expense of $1.1 million (2005 – $1.0 million) and decreased income taxes of $0.7 million (2005 – $0.8 million).

(xi) Regulatory Deferred Capital Asset Amortization

In 2006, Newfoundland Power deferred recovery of a $5.8 million increase in capital asset amortization in accordance with a PUB order. This amount will be recovered in a future period as determined by the PUB. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded and amortization costs in 2006 would have been $5.8 million higher (2005 – nil).

(xii) Lease Costs

On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination) (the "BTS Obligation") (Note 11). The agreement provides that FortisBC will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The recovery of the capital cost of the BTS, the cost of financing the BTS Obligation and the related operating costs are not being fully recovered by the Company in current customer rates since the rates include only the BTS lease payments on a cash basis. Of the regulatory deferred lease cost balance at December 31, 2006, $2.7 million (December 31, 2005 – $2.1 million) represented the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, amortization of the BTS and interest on the BTS Obligation would have been recorded, resulting in an increase in 2006 finance charges of $2.3 million (2005 – $2.2 million), a decrease in 2006 operating expenses of $2.6 million (2005 – $2.4 million) and an increase in 2006 amortization expense of $0.9 million (2005 – $0.9 million).

Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years (Notes 12 and 27). The Company is accounting for the lease as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term. As ordered by the BCUC, FortisBC recovers the Trail office lease payments from customers and records the lease costs on a cash basis. In the absence of rate regulation, the lease costs would be recorded on a straight-line basis, which would not result in any change in the expense recorded because the lease payments, on a cash basis, equalled the cost on a straight-line basis in both 2006 and 2005. Of the regulatory deferred lease cost balance at December 31, 2006, $1.7 million (December 31, 2005 – $1.7 million) represented the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase. The regulatory deferred lease cost asset is not subject to a regulatory return.

(xiii) Capital Charge – Point Lepreau Nuclear Generating Station ("Point Lepreau Station")

In 2001, Maritime Electric recorded a deferred asset in the amount of approximately $6.0 million with respect to the $450 million write-down of the Point Lepreau Station in 1998 by New Brunswick Power ("NB Power"), subject to an Entitlement Agreement between the two companies. Under the provisions of the *Electric Power Act* (Prince Edward Island), effective January 1, 2004, Maritime Electric was permitted to recover these deferred costs but under such terms, timelines and conditions as determined by IRAC. IRAC has issued two Orders permitting the continued amortization of the deferred asset based on the estimated useful life of the Point Lepreau Station which will be extended to 2035 after its scheduled refurbishment in 2008. In the absence of rate regulation, amortization expense in 2006 would have been $0.1 million lower (2005 – $0.6 million).

(xiv) Other Regulatory Assets

Other regulatory assets, included as current and/or long-term, primarily relate to FortisAlberta, FortisBC and FortisOntario.

FortisAlberta's other regulatory assets relate to rate hearing costs, self-insurance costs and a uniform system of accounts cost deferral. These expenses will be recognized in earnings when collected from customers in future rates upon approval by the AEUB. In the absence of rate regulation, these costs would be expensed in the period incurred.

FortisBC's other regulatory assets include costs deferred, as allowed by the BCUC, associated with developing a long-term transmission and distribution system plan, renewing the Canal Plant Agreement with BC Hydro and annual rate application proceedings. The other regulatory asset balances at FortisBC will be recovered from customers in future rates as approved by or upon approval by the BCUC. In the absence of rate regulation, the costs would have been expensed in the period incurred.

FortisOntario maintains regulatory accounts, as approved by the OEB, to adjust for the effect of cost of power and related costs above or below amounts recovered in rates and to defer transition costs associated with preparing for the competitive electricity market. In the absence of rate regulation, cost of power would be expensed in the period incurred and the transition costs would be appropriately deferred due to their capital nature; however, the amount to be recovered and the recovery period would not be subject to regulatory approval. Other regulatory assets at FortisOntario also included extraordinary costs of $1.6 million incurred as a result of an early winter storm that occurred in October 2006. FortisOntario filed an application in January 2007 seeking approval from the OEB to recover these storm costs through future customer rates. In the absence of rate regulation, these costs would be expensed in the period incurred.

Of the total balance of current and long-term other regulatory assets at December 31, 2006, $3.7 million is not subject to a regulatory return (2005 – $0.5 million). In the absence of rate regulation, the above current and long-term other regulatory assets would not be allowed, and during 2006 revenue would have been $0.4 million lower (2005 – $0.2 million), operating expenses would have been $4.3 million higher (2005 – $2.2 million), amortization expense would have been $0.7 million lower (2005 – $0.5 million) and corporate taxes would have been $0.5 million lower (2005 – $0.6 million).

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

(xv) Revenue Deferral for 2006 Rate Reduction

During 2006, FortisAlberta received revenue based on interim customer rates. On June 29, 2006, as part of the 2006/2007 Negotiated Settlement Agreement, the AEUB approved a 2006 rate reduction resulting in the deferral of $4.2 million in 2006 electricity rate revenue that will be refunded to customers in 2007. In the absence of rate regulation, revenue would have been $4.2 million higher in 2006 (2005 – nil). This revenue deferral is not subject to a regulatory return.

(xvi) Regulatory Future Income Tax Liability

During 2005, FortisAlberta collected in its approved customer rates $3.1 million relating to future income tax expense, which was recognized as a liability for customer rate-making purposes. For financial statement purposes, only $0.1 million of the $3.1 million was recognized as a future income tax expense. As such, the remaining $3.0 million of revenue was deferred. In the absence of rate regulation, revenue would have been $3.0 million higher in 2005. In accordance with the AEUB-approved 2006/2007 Negotiated Settlement Agreement, this balance is being refunded to customers in 2007 and therefore is classified as a current regulatory liability at December 31, 2006.

In 2005, as a result of collecting a portion of federal future income taxes within current rates, FortisAlberta had recognized all federal future income taxes within the financial statements. As a result, FortisAlberta had set up a regulatory liability equal to the amount of federal future income taxes recognized in the financial statements that had not yet been reflected in customer rates. These amounts would have been reflected in future rates to customers as timing differences reversed. As prescribed by the AEUB in the 2006/2007 Negotiated Settlement Agreement, effective January 1, 2006, FortisAlberta is now recovering income taxes through customer rates based only on income taxes that are currently payable for regulatory purposes and, as a result, the regulatory future income tax liability balance of $50.7 million was no longer recognized in 2006. This portion of the regulatory future income tax liability was not subject to a regulatory return.

(xvii) Regulatory Incentives

FortisBC's regulatory framework includes PBR mechanisms that allow for the recovery from or refund to customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and regulatory PBR incentive liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders. The 2005 regulatory PBR incentive liability was approved by the BCUC for repayment through reductions in 2006 electricity revenue, with an offsetting increase in other revenue. The 2006 regulatory PBR incentive liability has been approved by the BCUC for settlement in 2007 through a reduction in 2007 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded, which would have increased other revenue by $2.6 million in 2006 and decreased other revenue by $1.2 million in 2005.

(xviii) Regulatory Pension Deferral

This regulatory liability represents pension surplus at FortisAlberta that has not been reflected in customer rates and will result in a reduction of future customer rates when recognized. When future customer rates are reduced, this liability will be drawn down and reflected as a reduction of pension expense. In the absence of rate regulation, additional operating expenses of $0.6 million would have been recognized in 2006 (2005 – $3.6 million). This regulatory pension deferral is not subject to a regulatory return.

In 2005, the regulatory pension deferral at FortisAlberta also consisted of a current regulatory liability of $0.5 million resulting from the collection of pension expense in customer rates that had not yet been contributed into the pension plan. This portion of the balance was refunded to customers in 2006 through a reduction in customer rates. Therefore, in the absence of rate regulation, 2006 operating costs would have been $0.5 million higher (2005 – nil).

(xix) Regulatory Future Removal and Site Restoration Provision

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for these future removal and site restoration costs, net of salvage proceeds. Actual removal and site restoration costs, net of salvage proceeds, are recorded against this regulatory liability when incurred. This regulatory liability represents the amount of expected future removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulators. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in this regulatory liability with the offset recorded as an adjustment to accumulated amortization. In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than over the life of the assets through amortization expense. During 2006, the amount included in amortization expense associated with the provision for future removal and site restoration costs was $29.5 million (2005 – $21.7 million). During 2006, actual removal and site restoration costs, net of salvage proceeds, were $4.4 million (2005 – $1.9 million). In the absence of rate regulation, amortization expense would have been $29.5 million lower (2005 – $21.7 million) and operating expenses would have been $4.4 million higher (2005 – $1.9 million). In the absence of rate regulation, the provision for future removal and site restoration would not be recognized; therefore, long-term regulatory liabilities would have been $306.5 million lower (2005 – $280.9 million) and retained earnings would have been $306.5 million higher (2005 – $280.9 million).

(xx) *Unbilled Revenue Liability*

Belize Electricity records revenue derived from electricity sales on a billed basis (Note 2). Prior to January 1, 2006, Newfoundland Power also recorded revenue from electricity sales on a billed basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the PUB (Note 2). As a result, the $23.6 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized to December 31, 2005 on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $3.1 million of this regulatory liability in 2006. In the absence of rate regulation, revenue recorded on an accrual basis for 2006 would have been $1.8 million lower (2005 – $0.6 million higher).

(xxi) *Other Regulatory Liabilities*

Other regulatory liabilities, included as current and/or long-term, primarily relate to FortisOntario, FortisAlberta and Newfoundland Power.

As allowed under Cornwall Electric's Franchise Agreement, FortisOntario is guaranteed an annual gross margin on energy sold, subject to regulatory adjustments, and maintains a regulatory account to adjust for variances in actual gross margins from the guaranteed gross margins. In the absence of rate regulation, a guaranteed gross margin would not be allowed.

At FortisAlberta, other regulatory liabilities primarily include an amount owing to customers, as prescribed by the AEUB, relating to the difference in the actual amounts of certain deductions which are expected to be claimed for income tax purposes versus those that were included in 2006 customer rates. The 2005 balance of $0.9 million was refunded to customers in 2006 through a reduction in 2006 customer rates. During 2006, an additional $1.9 million of revenue was deferred due to the effect of the change in certain capital cost allowance rates. In the absence of rate regulation, these balances would not be deferred.

At Newfoundland Power, other regulatory liabilities include a PUB-approved purchased power unit cost variance reserve to limit variations in the cost of purchased power associated with the implementation of a demand and energy wholesale rate structure, effective January 1, 2005. Operation of the reserve limits purchased power cost volatility within a range approved by the PUB. The balance in reserve is reviewed by the PUB each year for disposition at their discretion. In the absence of rate regulation, fluctuations in purchased power cost would be recorded in earnings in the period in which they occurred.

Of the total balance of current and long-term other regulatory liabilities at December 31, 2006, $4.3 million is not subject to a regulatory return (2005 – $4.2 million). In the absence of rate regulation, current and long-term other regulatory liabilities would not be allowed, and during 2006 revenue would have been $0.8 million higher (2005 – $2.4 million), energy supply costs would have been $2.1 million lower (2005 – nil) and operating expenses would not have been impacted (2005 – $0.4 million higher).

December 31, 2006 and 2005

5. Deferred Charges and Other Assets

(in thousands)	**2006**	2005
Deferred pension costs *(Note 22)*	**$ 102,048**	$ 97,194
Unamortized debt discounts and deferred financing expenses	**22,617**	21,937
AESO contributions	**17,270**	–
Deferred loss on interest rate swap contract	**11,035**	12,443
Deferred recoverable and project costs	**10,055**	8,357
Energy management loans	**4,314**	3,944
Investment held as collateral	**2,792**	–
Other deferred charges	**4,704**	4,265
	$ 174,835	$ 148,140

6. Utility Capital Assets

2006 *(in thousands)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution	**$ 3,190,900**	**$ (881,978)**	**$ (425,641)**	**$ (96,119)**	**$ 1,787,162**
Transmission	**849,834**	**(210,579)**	**–**	**–**	**639,255**
Generation	**903,273**	**(245,156)**	**–**	**–**	**658,117**
Assets under construction	**130,026**	**–**	**–**	**–**	**130,026**
Other	**551,470**	**(191,179)**	**–**	**–**	**360,291**
	$ 5,625,503	**$ (1,528,892)**	**$ (425,641)**	**$ (96,119)**	**$ 3,574,851**

2005 *(in thousands)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution	$ 2,804,748	$ (781,196)	$ (398,418)	$ (100,913)	$ 1,524,221
Transmission	689,295	(182,377)	–	–	506,918
Generation	604,291	(137,722)	–	–	466,569
Assets under construction	95,052	–	–	–	95,052
Other	465,041	(157,408)	–	–	307,633
	$ 4,658,427	$ (1,258,703)	$ (398,418)	$ (100,913)	$ 2,900,393

The Corporation's distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and above). These assets include poles, wires and conductors, substations, support structures and other related equipment. Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment.

The cost of utility capital assets under capital lease at December 31, 2006 was $27.2 million (2005 – $26.2 million) and related accumulated amortization was $3.4 million (2005 – $2.5 million).

7. Income Producing Properties

	2006			2005
(in thousands)	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Buildings	**$ 421,361**	**$ (35,441)**	**$ 385,920**	$ 334,452
Land	**51,365**	**–**	**51,365**	45,208
Tenant inducements	**17,457**	**(11,133)**	**6,324**	6,578
Equipment	**39,454**	**(14,907)**	**24,547**	20,582
Construction in progress	**828**	**–**	**828**	7,788
	$ 530,465	**$ (61,481)**	**$ 468,984**	$ 414,608

The cost of income producing property assets under capital lease at December 31, 2006 was $11.0 million (2005 – $11.3 million) and related accumulated amortization was $6.6 million (2005 – $5.7 million).

8. Investments

(in thousands)	2006	2005
Caribbean Utilities	**$ –**	$ 164,808
Other investments	**2,536**	2,585
	$ 2,536	$ 167,393

On November 7, 2006, the Corporation, through a wholly owned subsidiary, acquired approximately an additional 16 per cent ownership interest in Caribbean Utilities and now owns an approximate 54 per cent controlling interest in the Company. Caribbean Utilities' balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis (Note 23). Prior to the acquisition of its controlling interest in Caribbean Utilities, Fortis accounted for its investment in Caribbean Utilities on an equity basis.

9. Goodwill

(in thousands)	2006	2005
Balance, beginning of year	**$ 512,139**	$ 514,041
Acquisition of controlling interest in Caribbean Utilities *(Note 23)*	**105,859**	–
Acquisition of Fortis Turks and Caicos *(Note 23)*	**38,747**	–
Acquisition of PLP *(Note 23)*	**–**	1,210
Cornwall Electric tax reassessment	**–**	(2,630)
Finalization of acquisition restructuring accruals	**–**	(482)
Foreign exchange translation impacts	**4,566**	–
Balance, end of year	**$ 661,311**	$ 512,139

Goodwill associated with the acquisition of a controlling interest in Caribbean Utilities on November 7, 2006 and the acquisition of Fortis Turks and Caicos on August 28, 2006 is denominated in US dollars as the investment in these companies is held through a wholly owned subsidiary of Fortis with a reporting currency in US dollars. Foreign currency translation impacts in 2006 were the result of the translation of US dollar-denominated goodwill and the impact of the depreciation of the Canadian dollar relative to the US dollar from the date of the acquisitions to December 31, 2006.

In 2005, goodwill was reduced by approximately $2.6 million upon the recognition of a future income tax asset as a result of a favourable resolution of a Canada Revenue Agency ("CRA") reassessment of a tax asset created when Cornwall Electric was acquired by a previous owner. A further $0.5 million reduction in goodwill during 2005 was a result of the finalization of certain restructuring cost accruals related to the acquisition of FortisAlberta and FortisBC.

December 31, 2006 and 2005

10. Credit Facility Borrowings

The credit facilities of the Corporation and its subsidiaries, as detailed below, bear interest at rates ranging from 4.5 per cent to 6.8 per cent at December 31, 2006 (December 31, 2005 – 3.3 per cent to 5.3 per cent). As at December 31, 2006, the Corporation and its subsidiaries had consolidated authorized lines of credit of $952.0 million, of which $546.7 million was unused.

The following summary outlines the Corporation's credit facilities by reporting segment as at December 31st.

($ millions)	Corporate	Regulated Utilities	Fortis Generation	Fortis Properties	**Total 2006**	Total 2005
Total credit facilities	315.0	622.2	2.3	12.5	**952.0**	747.1
Credit facilities utilized						
Short-term borrowings	–	(94.3)	–	(3.4)	**(97.7)**	(48.9)
Long-term debt *(Note 11)*	(84.1)	(151.4)	–	–	**(235.5)**	(85.8)
Letters of credit outstanding	(4.6)	(65.3)	–	(2.2)	**(72.1)**	(73.6)
Credit facilities available	226.3	311.2	2.3	6.9	**546.7**	538.8

At December 31, 2006 and December 31, 2005, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In January 2006, Newfoundland Power renegotiated its $100 million committed credit facility, extending the term from one year to three years, with maturity now in January 2009.

In January 2006, Maritime Electric's $25 million non-revolving unsecured short-term bridge financing was extended until July 2007. In August 2006, the amount available on Maritime Electric's operating credit facilities was increased to $30 million from $25 million.

In March 2006, FortisAlberta amended its committed unsecured credit facility, increasing the amount available to $200 million from $150 million and extending the maturity date from May 2008 to May 2010. In addition, the Company, with the consent of the lenders, has the ability to request an increase in the limit of this credit facility by $50 million under the same terms as the existing credit facility. In July 2006, FortisAlberta entered into a demand credit facility for $10 million, increasing the amount available to the Company under unsecured demand credit facilities to $20 million.

In May 2006, the maturity date of FortisBC's $50 million 364-day operating credit facility was extended to May 2007.

In June 2006, Fortis renegotiated and amended its $145 million and $50 million unsecured credit facilities, extending the maturity dates of these facilities from May 2008 and January 2009 to May 2010 and January 2011, respectively. Additionally, in July 2006, the amount available under the committed unsecured $145 million facility was increased to $250 million. These credit facilities can be used for general corporate purposes, including acquisitions.

At December 31, 2006, Regulated Utilities' credit facilities included both a US$2.0 million overdraft facility and a US$9.0 million standby credit facility for hurricane damage at Fortis Turks and Caicos. No drawings were made on these facilities as at December 31, 2006.

At December 31, 2006, Regulated Utilities' credit facilities included a total of US$22.7 million related to Caribbean Utilities, consisting of a US$10.0 million capital expenditures line of credit, a US$5.0 million operating line of credit, a US$5.0 million catastrophe standby loan and US$2.7 million in letters of credit and corporate credit card line. On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit to US$17.0 million and increasing each of its US$5.0 million operating line of credit and US$5.0 million catastrophe standby loan to US$7.5 million, for total credit facilities of US$34.7 million. These changes to the credit facilities in November 2006 have not been reflected in the table above as the Corporation has consolidated the balance sheet of Caribbean Utilities as at November 7, 2006.

11. Long-Term Debt and Capital Lease Obligations

(in thousands)	2006	2005
Regulated Utilities		
FortisAlberta		
5.33% Senior Unsecured Debentures, due 2014	**$ 200,000**	$ 200,000
6.22% Senior Unsecured Debentures, due 2034	**200,000**	200,000
5.40% Senior Unsecured Debentures, due 2036	**100,000**	–
	500,000	400,000
FortisBC		
Secured Debentures:		
11.00% Series E, due 2009	**5,250**	6,000
9.65% Series F, due 2012	**15,000**	15,000
8.80% Series G, due 2023	**25,000**	25,000
Unsecured Debentures:		
6.75% Series J, due 2009	**50,000**	50,000
5.48% Series 04-1, due 2014	**140,000**	140,000
8.77% Series H, due 2016	**25,000**	25,000
7.81% Series I, due 2021	**25,000**	25,000
5.60% Series 05-1, due 2035	**100,000**	100,000
Obligation under capital lease	**26,410**	25,792
	411,660	411,792
Newfoundland Power		
Secured first mortgage sinking fund bonds:		
11.875% Series AC, due 2007	**31,870**	32,270
10.550% Series AD, due 2014	**31,753**	32,153
10.900% Series AE, due 2016	**34,000**	34,400
9.000% Series AG, due 2020	**35,200**	35,600
10.125% Series AF, due 2022	**34,400**	34,800
8.900% Series AH, due 2026	**36,035**	36,435
6.800% Series AI, due 2028	**46,000**	46,500
7.520% Series AJ, due 2032	**72,000**	72,750
5.441% Series AK, due 2035	**58,800**	59,400
	380,058	384,308
Maritime Electric		
Secured first mortgage bonds:		
12.000% Series – due 2010	**15,000**	15,000
11.500% Series – due 2016	**12,000**	12,000
8.550% Series – due 2018	**15,000**	15,000
7.570% Series – due 2025	**15,000**	15,000
8.625% Series – due 2027	**15,000**	15,000
8.920% Series – due 2031	**20,000**	20,000
	92,000	92,000
FortisOntario		
7.092% Senior Unsecured Notes, due 2018	**30,000**	30,000
7.092% Senior Unsecured Notes, due 2018	**22,000**	22,000
	52,000	52,000

December 31, 2006 and 2005

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

(in thousands)	2006	2005
Belize Electricity		
Secured:		
RBTT Merchant Bank (BZ$15.2M)	**8,869**	10,997
First Caribbean International Bank	**–**	2,908
Unsecured:		
12.00% Debentures, due 2012 (BZ$17.0M)	**9,909**	9,888
9.50% Debentures, due 2021 (BZ$19.4M)	**11,318**	11,307
10.00% Debentures, due 2022 (BZ$23.9M)	**13,920**	11,378
Caribbean Development Bank (BZ$15.3M)	**8,915**	10,419
European Investment Bank (Euro 2.1M)	**3,254**	3,190
International Bank for Reconstruction and Development ("IBRD") (BZ$8.2M)	**4,799**	6,178
Toronto Dominion Bank (BZ$5.4M)	**3,172**	4,429
The Bank of Nova Scotia (BZ$4.4M)	**2,592**	–
Scotiabank & Trust (Cayman) Limited (BZ$6.0M)	**3,496**	–
M&T Bank (formerly All-First Bank), repaid during 2006	**–**	1,119
6.75% Term loan, repaid during 2006	**–**	443
	70,244	72,256
Caribbean Utilities		
Unsecured:		
3.00% European Investment Bank #3, due 2009 (US$1.3M)	**1,505**	–
8.47% Senior Loan Notes, due 2010 (US$6.0M)	**6,992**	–
6.47% Senior Loan Notes, due 2013 (US$17.5M)	**20,395**	–
7.64% Senior Loan Notes, due 2014 (US$24M)	**27,970**	–
6.67% Senior Loan Notes, due 2016 (US$30M)	**34,962**	–
5.09% Senior Loan Notes, due 2018 (US$40M)	**46,616**	–
5.96% Senior Loan Notes, due 2020 (US$30M)	**34,962**	–
	173,402	–
Fortis Turks and Caicos		
Unsecured:		
First Caribbean International Bank (US$5.2M)	**6,025**	–
Scotiabank (Turks and Caicos) Ltd. (US$14.7M)	**17,118**	–
	23,143	–
Non-Regulated – Fortis Generation		
Secured:		
BECOL		
Term loan, due 2011 (US$28.5M)	**33,161**	37,972
Exploits Partnership		
Term loan, due 2028	**62,912**	63,994
Walden Power Partnership		
9.44% WPP Mortgage, due 2013	**5,817**	6,397
	101,890	108,363

(in thousands)	**2006**	2005
Non-Regulated – Fortis Properties		
Secured:		
6.42% First mortgage, due 2007	**3,789**	–
6.85% First mortgage, due 2007	**4,685**	4,855
5.10% First mortgage, due 2010	**28,163**	29,068
5.35% First mortgage, due 2010	**11,729**	12,097
8.15% First mortgage, due 2010	**15,579**	16,522
9.47% First mortgage, due 2010	**10,871**	11,181
7.42% First mortgage, due 2012	**25,535**	26,383
7.77% First mortgage, due 2012	**21,134**	21,779
6.58% First mortgage, due 2013	**31,394**	32,614
7.30% First mortgage, due 2013	**28,069**	28,742
6.42% First mortgage, due 2014	**15,006**	15,290
7.50% First mortgage, due 2017	**41,134**	42,433
7.32% Senior notes, due 2019	**17,635**	18,521
Obligation under capital leases	**2,602**	3,885
Non-revolving credit facilities, due 2009 to 2010	**7,693**	–
Non-interest bearing note, repaid during 2006	**–**	428
	265,018	263,798
Fortis Inc.		
7.40% Senior Unsecured Debentures, due 2010	**100,000**	100,000
6.75% Unsecured Subordinated Convertible Debentures, due 2012 (US$10 million)	**11,123**	10,998
5.50% Unsecured Subordinated Convertible Debentures, due 2013 (US$10 million)	**11,349**	11,278
5.74% Senior Unsecured Notes, due 2014 (US$150 million)	**174,810**	174,450
5.50% Unsecured Subordinated Convertible Debentures, due 2016 (US$40 million)	**41,039**	–
	338,321	296,726
Long-term classification of credit facilities *(Note 10)*	**235,513**	85,823
Total long-term debt and capital lease obligations	**2,643,249**	2,167,066
Less: Current instalments of long-term debt and capital lease obligations	**84,786**	31,392
	$ 2,558,463	$ 2,135,674

Regulated Utilities

FortisAlberta

On April 21, 2006, FortisAlberta issued $100 million in Unsecured Debentures bearing interest at 5.40 per cent per annum, due April 21, 2036.

FortisBC

The Secured Series E, F and G Debentures are collaterized by a fixed and floating first charge on the assets of FortisBC. Sinking fund payments of $0.75 million per year are required for the Series E Secured Debentures.

On November 10, 2005, FortisBC issued $100 million in Unsecured Debentures bearing interest at 5.60 per cent, due November 9, 2035.

FortisBC has a capital lease obligation with respect to the BTS (Note 4 *(xii)*). Future minimum lease payments associated with this capital lease obligation are approximately $2.6 million per year over the remaining term of the lease agreement to 2032. The BTS lease obligation bears interest at a composite rate of 8.62 per cent.

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

Newfoundland Power and Maritime Electric
The Newfoundland Power and Maritime Electric first mortgage bonds are secured by a first fixed and specific charge on the respective utility's capital assets owned or to be acquired and by a floating charge on all other assets.

On August 15, 2005, Newfoundland Power closed a private placement of 5.441% $60 million first mortgage sinking fund bonds, due August 15, 2035.

Belize Electricity
The RBTT Merchant Bank loan bears interest at rates ranging from 5.75 per cent to 8.15 per cent and matures between 2010 and 2012. The loan is secured by a debenture over specific assets of the Company.

The 12.00% Unsecured Debentures can be called by Belize Electricity at any time after June 30, 2003 until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after June 30, 2002 by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

The 9.50% Unsecured Debentures can be called by Belize Electricity at any time after April 30, 2008 until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after April 30, 2008 by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

The 10.00% Unsecured Debentures can be called by Belize Electricity at any time after August 31, 2009 until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after August 31, 2009 by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

The Caribbean Development Bank loans bear interest at rates ranging from 6.25 per cent to 8.50 per cent and mature from 2007 to 2014. The European Investment Bank loan bears interest at 5.00 per cent and matures in 2014. The IBRD loan bears interest at 0.50 per cent per annum above the bank's "Cost of Qualified Borrowings" as defined in the loan agreement, and matures in 2011. The effective rate of interest as of December 31, 2006 was 5.35 per cent per annum (December 31, 2005 – 5.46 per cent). The Toronto Dominion Bank loan bears interest at 5.75 per cent and matures in 2009. The Bank of Nova Scotia loan bears interest at the prevailing six-month LIBOR plus 0.50 per cent per annum and matures in 2008. The Scotiabank & Trust (Cayman) Limited loan bears interest at the prevailing six-month LIBOR plus 5.00 per cent per annum and matures in 2010.

Fortis Turks and Caicos
The First Caribbean International Bank debt consists of two loans, one bearing interest at a floating rate of 0.75 per cent above LIBOR and the other bearing interest at a fixed rate of 5.65 per cent per annum. The First Caribbean International Bank loans are due in 2007 and 2015. The Scotiabank (Turks and Caicos) Ltd. debt consists of three loans, bearing interest at a floating rate of 1.00 per cent above LIBOR, a fixed rate of 6.04 per cent per annum and a fixed rate of 6.10 per cent per annum. The Scotiabank (Turks and Caicos) Ltd. loans have maturity dates between 2013 and 2016.

Fortis Generation

BECOL
The BECOL term loan, bearing interest at the prevailing six-month LIBOR plus 4.00 per cent, is secured by agreements covering all its property assets and undertakings. BECOL is party to an interest rate swap contract maturing on September 30, 2011 to hedge against interest exposures on the term loan. The contract has the effect of fixing the rate of interest at 9.45 per cent on the indebtedness.

Exploits Partnership
The Exploits Partnership non-recourse 25-year amortizing term loan bears interest at 7.55 per cent. A first, fixed and specific charge and security interest over all the assets of the Exploits Partnership and assignment of various agreements has been provided as security.

Walden Power Partnership
The WPP mortgage is secured by a fixed and floating charge over the assets of the WPP.

Fortis Properties

Fortis Properties' first mortgages are secured by a fixed and floating charge on specific income producing properties. The senior secured notes are collateralized by a fixed and specific mortgage and a charge on a specific income producing property.

The non-revolving credit facilities at Fortis Properties, bearing interest at Canadian Bankers' Acceptance rates, are secured by specific income producing properties. Fortis Properties is party to two interest rate swap contracts maturing on July 28, 2009 and October 15, 2010 to hedge against interest exposures on the non-revolving credit facilities. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities at 5.32 per cent and 6.16 per cent, respectively.

Fortis Properties has capital lease obligations which require future minimum lease payments of approximately $1.3 million in 2007 and a final payment of $1.5 million in 2008.

Fortis Inc.

The 7.40% Senior Unsecured Debentures are redeemable at the option of the Corporation at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Canada Yield, plus a premium ranging from 0.43 per cent to 0.87 per cent, together with accrued and unpaid interest thereon. There are also stated limitations for additional borrowings, dividend payments, share distributions and redemptions and the prepayment of subordinated debt.

The 6.75% Unsecured Subordinated Convertible Debentures are redeemable by the Corporation at par at any time on or after March 12, 2007, and are convertible, at the option of the holder, into the Corporation's Common Shares at $10.71 per share (US$9.19 per share). The Debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the Debentures.

The 5.50% Unsecured Subordinated Convertible Debentures are redeemable by the Corporation at par at any time on or after May 20, 2008, and are convertible, at the option of the holder, into the Corporation's Common Shares at $13.95 per share (US$11.97 per share). The Debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the Debentures.

The 5.74% Senior Unsecured Notes have stated limitations for additional borrowings, dividend payments, share distributions and redemptions and the prepayment of subordinated debt.

On November 7, 2006, the Corporation issued, by way of private placement, US$40 million of Unsecured Subordinated Convertible Debentures bearing interest at 5.5 per cent per annum, due November 7, 2016. The Debentures 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 $33.92 per share (US$29.11 per share). The Debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the Debentures.

The Unsecured Subordinated Convertible Debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $7.2 million at December 31, 2006 (December 31, 2005 – $1.5 million).

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years are as follows:

2007	$ 84.8 million
2008	$ 66.7 million
2009	$ 140.3 million
2010	$ 309.3 million
2011	$ 83.5 million

December 31, 2006 and 2005

12. Deferred Credits

(in thousands)		**2006**		2005
Other post-employment benefit obligations *(Note 22)*	**$**	**51,517**	$	43,743
Supplementary defined benefit obligations *(Note 22)*		**12,188**		9,882
Customer deposits		**4,772**		2,483
Deferred gain on foreign currency swap contract		**2,784**		3,526
Trail lease costs *(Note 4 (xii))*		**1,691**		1,730
Other deferred credits		**6,035**		2,897
	$	**78,987**	$	64,261

13. Non-Controlling Interest

The non-controlling interest consists of the non-controlling interest in the net assets of Caribbean Utilities, Belize Electricity, Exploits Partnership and preference shares of Newfoundland Power.

(in thousands)		**2006**		2005
Caribbean Utilities *(Note 23)*	**$**	**78,803**	$	–
Belize Electricity		**42,206**		28,370
Exploits Partnership		**2,357**		3,989
Preference shares of Newfoundland Power		**7,139**		7,196
	$	**130,505**	$	39,555

14. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2006**			2005		
	Balance Sheet Classification	**Number of Shares**		**Amount *(in thousands)***	Number of Shares		Amount *(in thousands)*
(i) First Preference Shares, Series C	Debt	**5,000,000**	**$**	**122,992**	5,000,000	$	122,992
(ii) First Preference Shares, Series E	Debt	**7,993,500**		**196,500**	7,993,500		196,500
Total classified as debt		**12,993,500**	**$**	**319,492**	12,993,500	$	319,492
(iii) First Preference Shares, Series F	Equity	**5,000,000**	**$**	**122,466**	–	$	–

(i) First Preference Shares, Series C

The 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 at such time.

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 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 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 substitute purchasers.

As the First Preference Shares, Series C are redeemable at the option of the shareholder, they meet the definition of a financial liability and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

(ii) First Preference Shares, Series E

The First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends in the amount 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, Series E for cash or arrange for the sale of those shares to other purchasers.

As the First Preference Shares, Series E are redeemable at the option of the shareholder, they meet the definition of a financial liability and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

(iii) First Preference Shares, Series F

On September 28, 2006, the Corporation issued 5,000,000 First Preference Shares, Series F at $25.00 per share for net after-tax proceeds of $122.5 million.

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.2250 per share per annum.

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.

As the First Preference Shares, Series F are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the statement of earnings immediately before arriving at net earnings applicable to common shares.

December 31, 2006 and 2005

15. Common Shares

Authorized: an unlimited number of Common Shares without nominal or par value.

Issued and Outstanding	2006		2005	
	Number of Shares	Amount (in thousands)	Number of Shares	Amount (in thousands)
Common Shares	104,091,542	$ 828,985	103,203,981	$ 813,304

Common Shares issued during the year were as follows:

	2006		2005	
	Number of Shares	Amount (in thousands)	Number of Shares	Amount (in thousands)
Opening balance	103,203,981	$ 813,304	95,529,292	$ 675,215
Public offering	–	–	6,960,000	126,072
Partial consideration in business acquisition *(Note 23)*	–	–	23,668	443
Consumer Share Purchase Plan	77,213	1,896	86,588	1,799
Dividend Reinvestment Plan	176,264	4,342	171,301	3,526
Employee Share Purchase Plan	135,502	3,279	151,724	3,088
Stock Option Plans	498,582	6,164	281,408	3,161
Ending balance	104,091,542	$ 828,985	103,203,981	$ 813,304

On March 1, 2005, Fortis issued 6,960,000 Common Shares of the Corporation at $18.66 per common share. The common share issue resulted in gross proceeds of approximately $130 million. Net proceeds after tax-effected issuance costs totalled $126.1 million. The proceeds of the issuance were used to pay outstanding indebtedness and for general corporate purposes.

On May 31, 2005, Fortis issued 23,668 Common Shares of the Corporation at a fair value of $18.71 per common share, the five-day average trading price of the Corporation's Common Shares for the last five trading days immediately preceding the acquisition, to the shareholders of PLP, combined with a cash payment, to acquire all of the issued and outstanding common and preference shares of PLP.

At December 31, 2006, 10,958,906 Common Shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans.

As at December 31, 2006, $0.7 million (December 31, 2005 – $1.3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 103,578,222 and 101,749,758 for 2006 and 2005, respectively.

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

Earnings per common share are as follows:

	2006			2005		
	Earnings *(in thousands)*	**Weighted Average Shares** *(in thousands)*	**Earnings per Common Share**	Earnings *(in thousands)*	Weighted Average Shares *(in thousands)*	Earnings per Common Share
Net earnings applicable to common shares	**$ 147,187**			$ 137,097		
Weighted average shares outstanding		**103,578**			101,750	
Basic Earnings per Common Share			**$ 1.42**			$ 1.35
Effect of dilutive securities:						
Stock options	**–**	**1,160**		–	1,046	
Preference Shares *(Notes 14 (i) and (ii) and 18)*	**16,606**	**14,096**		16,606	19,689	
Convertible debentures	**1,364**	**2,128**		1,104	1,925	
Diluted Earnings per Common Share	**$ 165,157**	**120,962**	**$ 1.37**	$ 154,807	124,410	$ 1.24

16. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis Inc. and its subsidiaries options to purchase Common Shares of the Corporation. At December 31, 2006, the Corporation had the following stock option plans: 2006 Stock Option Plan ("2006 Plan"), 2002 Stock Option Plan ("2002 Plan") and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the Executive Stock Option Plan and the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options to be granted by Fortis will be granted under the 2006 Plan. Options granted under the 2006 Plan will have a maximum term of seven years, which is reduced from 10 years under the 2002 Plan, and will expire no later than three years after the termination, death or retirement of the optionee. Directors are not eligible to receive grants of options under the 2006 Plan.

Number of Options:	**2006**	2005
Options outstanding, beginning of year	**3,421,876**	2,882,588
Granted	**626,761**	845,720
Cancelled	**–**	(25,024)
Exercised	**(498,582)**	(281,408)
Options outstanding, end of year	**3,550,055**	3,421,876
Options vested, end of year	**1,739,759**	1,452,602
Weighted Average Exercise Prices:		
Outstanding, beginning of year	**$ 14.18**	$ 12.57
Granted	**22.94**	18.49
Cancelled	**–**	16.56
Exercised	**11.45**	10.44
Outstanding, end of year	**16.11**	14.18

December 31, 2006 and 2005

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

Details of stock options outstanding as at December 31, 2006 are as follows:

Number of Options	Exercise Price	Expiry Date
209,984	$ 9.57	2011
515,148	$ 12.03	2012
627,500	$ 12.81	2013
675,648	$ 15.28	2014
12,000	$ 15.23	2014
68,557	$ 14.55	2014
752,717	$ 18.40	2015
28,000	$ 18.11	2015
33,740	$ 20.82	2015
626,761	$ 22.94	2016
3,550,055		

Details of stock options vested as at December 31, 2006 are as follows:

Number of Options	Exercise Price	Expiry Date
209,984	$ 9.57	2011
515,148	$ 12.03	2012
453,020	$ 12.81	2013
329,628	$ 15.28	2014
6,000	$ 15.23	2014
29,467	$ 14.55	2014
181,077	$ 18.40	2015
7,000	$ 18.11	2015
8,435	$ 20.82	2015
1,739,759		

The weighted average exercise price of stock options vested as at December 31, 2006 was $13.34.

On February 28, 2006, the Corporation granted 626,761 options on Common Shares under its 2002 Stock Option Plan at the five-day average trading price immediately preceding the date of grant of $22.94. These options vest evenly over a four-year period on each anniversary of the date of grant. The options expire 10 years after the date of grant. The fair market value of each option granted was $3.90 per option.

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

	February 28, 2006
Dividend yield (%)	3.02
Expected volatility (%)	16.7
Risk-free interest rate (%)	4.12
Weighted-average expected life (years)	7.5

Under the fair value method, compensation expense associated with stock options was $2.0 million for the year ended December 31, 2006 (2005 – $1.6 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit of their annual retainer to a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation. DSUs are credited to participating directors as of January 1st of each year by dividing the total applicable annual retainer by the daily average of the high and low board lot trading prices of the Common Shares for the last five trading days immediately preceding the date of grant of the DSUs. Notional dividends are assumed to accrue to the holder of the DSU and be reinvested on the quarterly dividend payment dates of the Corporation's Common Shares. Upon retirement from the Board of Directors, a director participant in the DSU Plan will receive a cash payment equivalent to the number of DSUs credited to the notional account multiplied by the daily average of the high and low board lot trading prices of the Corporation's Common Shares for the last five trading days immediately preceding the date of payment.

Number of DSUs:	**2006**	2005
DSUs outstanding, beginning of year	**24,986**	13,312
Granted	**22,101**	10,998
Dividends credited	**1,198**	676
DSUs paid out	**(1,326)**	–
DSUs outstanding, end of year	**46,959**	24,986

For the year ended December 31, 2006, expenses of $0.8 million were recorded in relation to the Directors' DSU Plan (2005 – $0.4 million).

RSU Plan

In 2004, the Corporation introduced the RSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each RSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation. Notional dividends are assumed to accrue to the holder of the RSU and be reinvested on the quarterly dividend payment dates of the Corporation's Common Shares. The RSU maturation period is three years from the date of grant, at which time a cash payment is made to the President and CEO based on the number of RSUs outstanding multiplied by the daily average of the high and low board lot trading prices of the Corporation's Common Shares for the last five trading days immediately preceding the date of payment.

Number of RSUs:	**2006**	2005
RSUs outstanding, beginning of year	**36,855**	19,428
Granted	**28,400**	16,520
Dividends credited	**1,590**	907
RSUs outstanding, end of year	**66,845**	36,855

For the year ended December 31, 2006, expenses of $0.7 million were recorded in relation to the RSU Plan (2005 – $0.3 million).

December 31, 2006 and 2005

17. Foreign Currency Translation Adjustment

(in thousands)	2006	2005
Balance, beginning of year	**$ (16,312)**	$ (15,497)
Effect of exchange rate changes on the translation of foreign net investments	**(30,061)**	(4,666)
Effect of exchange rate changes on the translation of long-term debt hedged against foreign net investments	**(5,135)**	3,851
Balance, end of year	**$ (51,508)**	$ (16,312)

On November 7, 2006, the Corporation, through a wholly owned subsidiary, acquired approximately an additional 16 per cent ownership interest in Caribbean Utilities and now holds an approximate 54 per cent controlling interest in the Company. On this date, $39.3 million was charged to the foreign currency translation adjustment account, representing the impact of the appreciation of the Canadian dollar relative to the US dollar between the original share purchase dates and the recording of the net investment in Caribbean Utilities as a self-sustaining foreign operation, effective November 7, 2006.

18. Finance Charges

(in thousands)	2006	2005
Amortization of debt and stock issue expenses	**$ 683**	$ 1,093
Interest – Long-term debt and capital lease obligations	**154,308**	142,710
– Short-term borrowings	**6,339**	5,912
Interest charged to construction *(Note 2)*	**(4,389)**	(6,727)
Interest earned	**(3,493)**	(3,434)
Unrealized foreign exchange gain on long-term debt	**(1,725)**	(2,335)
Dividends on preference shares *(Notes 14 (i) and (ii) and 15)*	**16,606**	16,606
	$ 168,329	$ 153,825

19. Gain on Sale of Income Producing Property

On June 28, 2006, Fortis Properties sold the Days Inn Sydney for gross proceeds of $4.5 million, resulting in a $2.1 million ($1.6 million after-tax) gain.

20. Gain on Settlement of Contractual Matters

In the first quarter of 2005, Fortis recorded a $10.0 million ($7.9 million after-tax) gain resulting from the settlement of contractual matters between FortisOntario Inc. and OPGI.

21. Corporate Taxes

Corporate taxes differ from the amount that would be expected by applying the enacted Canadian federal and provincial statutory tax rates to earnings before corporate taxes. The following is a reconciliation of the consolidated statutory tax rate to the consolidated effective tax rate:

(%)	**2006**	2005
Statutory tax rate	**35.2**	35.3
Preference share dividends	**3.2**	2.8
Large corporations' tax	**–**	2.1
Difference between Canadian statutory rates and those applicable to foreign subsidiaries	**(6.8)**	(3.6)
Items capitalized for accounting but expensed for income tax purposes	**(10.7)**	(0.1)
Other timing differences	**(1.2)**	(1.6)
Impact of reduction in income tax rates on future income tax balances	**(2.4)**	–
Change in revenue recognition policy at Newfoundland Power *(Note 2)*	**0.8**	–
Maritime Electric tax reassessment *(Note 28 (a))*	**0.9**	–
Cornwall Electric tax reassessment	**–**	(0.8)
Pension costs	**(0.4)**	(0.8)
Other	**(1.4)**	(0.4)
Effective tax rate	**17.2**	32.9

The AEUB-approved 2006/2007 Negotiated Settlement Agreement, effective January 1, 2006, resulted in a change in the income tax methodology used at FortisAlberta whereby future income tax expense for federal income tax, associated with specified timing differences, is no longer being recognized. The effect of the change in income tax methodology has been a decrease in income tax expense during the year compared to 2005, primarily associated with the timing of recognition for income tax purposes of those items capitalized for accounting purposes (Note 2).

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

(in thousands)	**2006**	2005
Canadian		
Current taxes	**$ 19,495**	$ 55,768
Future income taxes	**9,697**	11,792
	29,192	67,560
Foreign		
Current taxes	**2,786**	2,326
Future income taxes	**560**	530
	3,346	2,856
Corporate tax expense	**$ 32,538**	$ 70,416

December 31, 2006 and 2005

21. Corporate Taxes (cont'd)

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

(in thousands)	2006	2005
Future income tax liability (asset)		
Utility capital assets and income producing properties	**$ 45,869**	$ (9,570)
ECAM	**4,370**	5,123
Other regulatory assets and liabilities	**10,980**	3,826
Intangible assets	**3,449**	5,067
Tenant inducements	**2,171**	2,382
Deferred charges	**954**	981
Employee future benefits	**(8,873)**	(8,400)
Losses carried forward	**(8,378)**	(8,151)
Share issue and debt financing costs	**(930)**	(2,010)
Other	**2,031**	3,369
Net future income tax liability (asset)	**$ 51,643**	$ (7,383)
Current future income tax liability	**$ 959**	$ 6,714
Long-term future income tax asset	**(7,053)**	(58,815)
Long-term future income tax liability	**57,737**	44,718
Net future income tax liability (asset)	**$ 51,643**	$ (7,383)

As at December 31, 2006, the Corporation had approximately $24.4 million (2005 – $26.7 million) in non-capital and capital losses carried forward, of which $0.3 million (2005 – $0.6 million) in capital losses has not been recognized in the financial statements. The non-capital loss carry forwards expire between 2008 and 2016.

22. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other post-employment benefit plans for qualifying employees.

For the defined benefit pension arrangements, the accrued benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31st of each year for the Corporation and Newfoundland Power; as at September 30th of each year for FortisAlberta, FortisBC and FortisOntario; and as at April 30th of each year for Caribbean Utilities. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2003 for FortisOntario; as of December 31, 2004 for FortisAlberta and FortisBC; as of December 31, 2005 for the Corporation and Newfoundland Power; and as of April 30, 2006 for Caribbean Utilities. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company.

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

Plan assets as at December 31st

(%)	2006	2005
Canadian equities	**45**	46
Fixed income	**39**	38
Foreign equities	**15**	14
Real estate	**1**	1
Cash	**–**	1
	100	100

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

				2006			
($ thousands)	**Fortis Alberta**	**FortisBC**	**NF Power**	**Fortis Ontario**	**Caribbean Utilities**	**Fortis Inc.**	**Total**
Accrued benefit obligation	**21,275**	**117,928**	**239,176**	**24,928**	**5,796**	**4,266**	**413,369**
Plan assets	**18,560**	**94,714**	**250,226**	**20,970**	**2,370**	**3,752**	**390,592**
Funded (unfunded)	**(2,715)**	**(23,214)**	**11,050**	**(3,958)**	**(3,426)**	**(514)**	**(22,777)**

				2005			
($ thousands)	Fortis Alberta	FortisBC	NF Power	Fortis Ontario	Caribbean Utilities	Fortis Inc.	Total
Accrued benefit obligation	19,815	114,324	226,725	24,708	–	4,218	389,790
Plan assets	17,285	86,136	223,370	19,896	–	3,261	349,948
Unfunded	(2,530)	(28,188)	(3,355)	(4,812)	–	(957)	(39,842)

December 31, 2006 and 2005

22. Employee Future Benefits (cont'd)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		Other Post-Employment Benefit Plans Unfunded	
(in thousands, except as indicated)	**2006**	2005	**2006**	2005	**2006**	2005
Change in accrued benefit obligation						
Balance, beginning of year	**$ 389,790**	$ 317,145	**$ 13,887**	$ 13,191	**$ 102,617**	$ 82,442
Liability associated with acquisitions	**5,796**	–	**–**	–	**–**	–
Current service costs	**7,480**	5,387	**673**	470	**2,769**	1,680
Employee contributions	**3,418**	3,077	**–**	–	**–**	–
Interest costs	**19,948**	19,756	**819**	727	**5,272**	4,856
Benefits paid	**(18,610)**	(17,557)	**(419)**	(386)	**(4,118)**	(2,221)
Actuarial loss (gain)	**1,912**	50,070	**235**	(115)	**1,989**	15,762
Plan amendments	**3,538**	11,277	**1,517**	–	**–**	98
Special termination benefits	**–**	635	**–**	–	**–**	–
Net transfers in	**97**	–	**–**	–	**–**	–
Balance, end of year	**$ 413,369**	$ 389,790	**$ 16,712**	$ 13,887	**$ 108,529**	$ 102,617
Change in value of plan assets						
Balance, beginning of year	**$ 349,948**	$ 308,983	**$ –**	$ –	**$ –**	$ –
Assets associated with acquisitions	**2,370**	–	**–**	–	**–**	–
Actual return on plan assets	**35,361**	42,768	**–**	–	**–**	–
Benefits paid	**(18,610)**	(17,557)	**(419)**	(386)	**(4,118)**	(2,221)
Employee contributions	**3,418**	3,077	**–**	–	**–**	–
Employer contributions	**18,008**	12,677	**419**	386	**4,118**	2,221
Net transfers in	**97**	–	**–**	–	**–**	–
Balance, end of year	**$ 390,592**	$ 349,948	**$ –**	$ –	**$ –**	$ –
Funded status						
Deficit, end of year	**$ (22,777)**	$ (39,842)	**$ (16,712)**	$ (13,887)	**$ (108,529)**	$ (102,617)
Unamortized net actuarial loss	**85,354**	98,940	**3,026**	3,303	**38,210**	38,254
Unamortized past service costs	**17,689**	13,748	**986**	–	**274**	319
Unamortized transitional obligation	**20,724**	23,047	**512**	702	**18,384**	20,176
Employer contributions after measurement date	**1,058**	1,301	**–**	–	**144**	125
Accrued benefit asset (liability), end of year *(Notes 5 and 12)*	**$ 102,048**	$ 97,194	**$ (12,188)**	$ (9,882)	**$ (51,517)**	$ (43,743)
Significant assumptions						
Discount rate during year *(%)*	**5.00–5.25**	6.00–6.25	**5.00–5.25**	6.00–6.25	**5.00–5.25**	6.00–6.25
Discount rate as at December 31st *(%)*	**5.00–5.25**	5.00–5.25	**5.25**	5.00–5.25	**5.00–5.25**	5.00–5.25
Expected long-term rate of return on plan assets *(%)*	**6.50–7.50**	7.00–7.50	**–**	–	**–**	–
Rate of compensation increase *(%)*	**3.50–4.00**	3.50–4.50	**3.50–4.00**	3.50–4.50	**3.50–4.00**	3.50–4.00
Health care cost trend increase as at December 31st *(%)*	**–**	–	**–**	–	**4.50–10.00**	4.50–10.00
Expected average remaining service life of active employees *(years)*	**12–15**	12–16	**3–15**	4–16	**11–17**	12–17

(in thousands)	Defined Benefit Pension Plans Funded 2006	2005	Supplementary Defined Benefit Plans Unfunded 2006	2005	Other Post-Employment Benefit Plans Unfunded 2006	2005
Components of net benefit expense						
Current service costs	**$ 7,480**	$ 5,387	**$ 673**	$ 470	**$ 2,769**	$ 1,680
Interest costs	**19,948**	19,756	**819**	727	**5,272**	4,856
Actual return on plan assets	**(35,361)**	(42,768)	**–**	–	**–**	–
Actuarial loss (gain)	**1,912**	50,070	**235**	(115)	**1,989**	15,762
Costs arising in the year	**(6,021)**	32,445	**1,727**	1,082	**10,030**	22,298
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**10,692**	20,432	**–**	–	**–**	–
Actuarial gain (loss)	**3,547**	(46,609)	**277**	279	**44**	(14,694)
Past service costs	**2,079**	1,345	**532**	–	**–**	–
Special termination benefits	**–**	635	**–**	–	**–**	–
Transitional obligation and amendments	**2,323**	2,325	**190**	191	**1,838**	1,838
Settlements and curtailments	**–**	49	**–**	–	**–**	–
Regulatory adjustment	**(1,531)**	(40)	**(463)**	30	**(5,552)**	(5,425)
Net benefit expense	**$ 11,089**	$ 10,582	**$ 2,263**	$ 1,582	**$ 6,360**	$ 4,017

For 2006, the effects of changing the health care cost trend rate by a 1 per cent increase and a 1 per cent decrease are as follows:

(in thousands)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 18,054**	**$ (14,386)**
Increase (decrease) in service and interest costs	**$ 1,534**	**$ (1,140)**

During 2006, the Corporation expensed $4.0 million (2005 – $3.5 million) related to defined contribution pension plans.

23. Business Acquisitions

2006

Caribbean Utilities

On November 7, 2006, Fortis, through a wholly owned subsidiary, acquired an aggregate of 4,113,116 of the outstanding Class A Ordinary Shares of Caribbean Utilities for US$11.89 per share under a private agreement with International Power Holdings Ltd. (“IPHL”) and four other vendors affiliated with IPHL. The aggregate purchase price of $55.7 million (US$49.0 million), including acquisition costs, was financed through cash consideration from the issuance of US$40 million Unsecured Subordinated Convertible Debentures, combined with drawings on the Corporation’s credit facilities.

Following this acquisition, Fortis controls Caribbean Utilities by beneficially owning 13,565,511, or approximately 54 per cent, of the outstanding Class A Ordinary Shares of Caribbean Utilities.

The acquisition has been accounted for using the purchase method. Caribbean Utilities’ balance sheet as at November 7, 2006 has been consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis will consolidate Caribbean Utilities’ financial statements on a two-month lag basis and will include Caribbean Utilities’ January 31, 2007 balance sheet and statements of earnings and cash flows for the three-month period ended January 31, 2007. During 2006 and 2005, the statement of earnings of Fortis reflected the Corporation’s previous approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on a two-month equity lag basis. Caribbean Utilities’ financial results are reported in the Corporation’s Regulated Utilities – Caribbean operating segment.

23. Business Acquisitions (cont'd)

The determination of revenues and earnings of Caribbean Utilities is based on a regulated rate of return that is applied to historic values and does not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximate fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The Corporation has accounted for the acquisition of the controlling interest in Caribbean Utilities as a two-step acquisition for the purpose of purchase price allocation and the assigning of costs to identifiable assets, goodwill and intangible assets, if any.

Upon acquiring additional Class A Ordinary Shares of Caribbean Utilities in January 2003, the Corporation's ownership interest in Caribbean Utilities increased to approximately 37 per cent. As of January 2003, this investment was accounted for on an equity basis and, therefore, was considered the first step in the two-step acquisition process. Previous to January 2003, the Corporation's approximate 22 per cent ownership interest in Caribbean Utilities was accounted for on a cost basis. On November 7, 2006, the Corporation increased its ownership interest in Caribbean Utilities to approximately 54 per cent, representing a controlling interest in the Company and, therefore, was considered the second step in the two-step acquisition process.

The total purchase price allocation, subject to final adjustments, if any, to be made by September 30, 2007, is estimated as follows:

(in thousands)	
Fair value assigned to net assets:	
Utility capital assets	**$ 318,587**
Current assets	**29,704**
Goodwill	**105,859**
Regulatory assets	**13,367**
Other assets	**1,850**
Current liabilities	**(28,764)**
Assumed long-term debt (including current portion)	**(178,146)**
Non-controlling interest	**(76,836)**
Other liabilities	**(190)**
	185,431
Cash	**2,676**
	$ 188,107

Fortis Turks and Caicos

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all issued and outstanding common shares of P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively referred to as "Fortis Turks and Caicos") for aggregate consideration of approximately $97.7 million (US$87.8 million). The purchase price, net of assumed debt and acquisition costs, of $75.6 million (US$68.0 million) was initially financed, through cash consideration, by way of drawings on the Corporation's credit facilities that were repaid in part, with partial proceeds from the issuance of First Preference Shares, Series F of Fortis on September 28, 2006.

The acquisition has been accounted for using the purchase method, whereby the results of full operations of Fortis Turks and Caicos have been included in the consolidated financial statements of Fortis in the Regulated Utilities – Caribbean segment, commencing August 28, 2006. The determination of revenues and earnings of Fortis Turks and Caicos is based on a regulated rate of return that is applied to historic values and does not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximate fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The purchase price allocation, subject to final adjustments, if any, to be made by June 30, 2007, is estimated as follows:

(in thousands)	PPC	Atlantic	Total
Fair value assigned to net assets:			
Utility capital assets	$ 45,196	$ 605	**$ 45,801**
Current assets	17,787	815	**18,602**
Goodwill	38,747	–	**38,747**
Other assets	905	–	**905**
Current liabilities	(3,162)	(105)	**(3,267)**
Assumed long-term debt (including current portion)	(22,072)	–	**(22,072)**
Other liabilities	(2,057)	(1,075)	**(3,132)**
	$ 75,344	$ 240	**$ 75,584**

Fortis Properties

On November 1, 2006, Fortis Properties purchased assets comprised of four hotels in Alberta and British Columbia for an aggregate cash purchase price of approximately $52.0 million, including assumed debt and acquisition costs. The four hotels were the Holiday Inn Express and Suites, and Best Western in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia.

The acquisition has been accounted for using the purchase method, whereby the results of full operations of the hotels have been included in the consolidated financial statements of Fortis from the date of acquisition, commencing November 1, 2006.

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

(in thousands)	
Fair value assigned to net assets:	
Income producing properties	**$ 51,803**
Other assets	**362**
Other liabilities	**(245)**
Assumed long-term debt (including current portion)	**(11,571)**
	$ 40,349

2005

Acquisition of Princeton Light and Power Company, Limited

On May 31, 2005, Fortis, through an indirect wholly owned subsidiary, acquired all issued and outstanding common and preference shares of PLP for an aggregate purchase price of $3.7 million. PLP is an electric utility that serves approximately 3,500 customers, mainly in Princeton, British Columbia. Effective January 1, 2007, PLP was amalgamated with FortisBC Inc. as part of an internal corporate reorganization.

The acquisition was financed through a combination of cash consideration of $3.3 million and the issuance of 23,668 Common Shares of the Corporation at a fair value of $18.71 per common share, the five-day average trading price of the Corporation's Common Shares for the last five trading days immediately preceding the acquisition.

The acquisition has been accounted for using the purchase method, whereby the results of full operations of PLP have been included in the consolidated financial statements of Fortis in the Regulated Utilities – Canadian segment, commencing May 31, 2005. The determination of revenues and earnings of PLP is based on a regulated rate of return that is applied to historic values and does not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on individual assets and liabilities because all economic benefits and obligations associated with them beyond the regulated rate of return will accrue to customers. The book value of PLP's assets and liabilities has been assigned as fair value for purchase price allocation.

23. Business Acquisitions (cont'd)

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

(in thousands)

Fair value assigned to net assets:		
Utility capital assets	$	6,381
Current assets		1,168
Goodwill		1,210
Other assets		445
Current liabilities		(1,109)
Assumed long-term debt (including current portion)		(3,990)
Future income taxes		(329)
Other liabilities		(75)
	$	3,701

Fortis Properties

On February 1, 2005, Fortis Properties purchased assets comprising the businesses of one Greenwood Inn hotel in Manitoba and two Greenwood Inn hotels in Alberta for cash consideration of $62.8 million. The acquisition has been accounted for using the purchase method, whereby the results of full operations of the hotels have been included in the consolidated financial statements of Fortis from the date of acquisition, commencing February 1, 2005.

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

(in thousands)

Fair value assigned to net assets:		
Income producing properties	$	62,600
Other assets		229
Other liabilities		(69)
	$	62,760

24. a) Segmented Information

Information by reportable segment is as follows:

Year ended December 31, 2006 *(in thousands of dollars)*	**Regulated Utilities** Fortis Alberta	Fortis BC	NF Power	Maritime Electric	Fortis Ontario	Total Canadian	Total Caribbean[(1)]	**Non-Regulated** Fortis Generation	Fortis Properties	Corporate	Inter-segment elimi-nations	Consoli-dated
Operating revenues	**250,776**	**215,618**	**421,264**	**122,407**	**130,034**	**1,140,099**	**101,039**	**79,387**	**162,928**	**9,037**	**(30,492)**	**1,461,998**
Equity income	**–**	**–**	**–**	**–**	**–**	**–**	**9,738**	**–**	**–**	**–**	**–**	**9,738**
Energy supply costs	**–**	**67,576**	**257,157**	**72,980**	**97,762**	**495,475**	**56,823**	**6,233**	**–**	**–**	**(18,046)**	**540,485**
Operating expenses	**115,230**	**63,103**	**53,996**	**12,828**	**14,642**	**259,799**	**12,778**	**15,150**	**105,323**	**10,592**	**(5,055)**	**398,587**
Amortization	**68,766**	**27,333**	**33,129**	**10,148**	**5,407**	**144,783**	**6,807**	**10,496**	**12,456**	**2,969**	**–**	**177,511**
Operating income	**66,780**	**57,606**	**76,982**	**26,451**	**12,223**	**240,042**	**34,369**	**47,508**	**45,149**	**(4,524)**	**(7,391)**	**355,153**
Finance charges	**30,118**	**23,423**	**32,677**	**10,255**	**5,074**	**101,547**	**4,742**	**10,013**	**20,973**	**38,445**	**(7,391)**	**168,329**
Gain on sale of income producing property	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(2,088)**	**–**	**–**	**(2,088)**
Corporate taxes	**(4,734)**	**6,767**	**13,639**	**6,429**	**3,082**	**25,183**	**1,525**	**8,125**	**7,563**	**(9,858)**	**–**	**32,538**
Non-controlling interest	**–**	**–**	**588**	**–**	**–**	**588**	**4,490**	**2,690**	**–**	**(166)**	**–**	**7,602**
Net earnings (loss)	**41,396**	**27,416**	**30,078**	**9,767**	**4,067**	**112,724**	**23,612**	**26,680**	**18,701**	**(32,945)**	**–**	**148,772**
Preference share dividends	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**1,585**	**–**	**1,585**
Net earnings (loss) applicable to common shares	**41,396**	**27,416**	**30,078**	**9,767**	**4,067**	**112,724**	**23,612**	**26,680**	**18,701**	**(34,530)**	**–**	**147,187**
Goodwill	**228,615**	**220,719**	**–**	**19,858**	**42,947**	**512,139**	**149,172**	**–**	**–**	**–**	**–**	**661,311**
Identifiable assets	**1,158,546**	**809,923**	**936,300**	**317,331**	**128,653**	**3,350,753**	**678,803**	**245,854**	**485,732**	**43,368**	**(18,380)**	**4,786,130**
Total assets	**1,387,161**	**1,030,642**	**936,300**	**337,189**	**171,600**	**3,862,892**	**827,975**	**245,854**	**485,732**	**43,368**	**(18,380)**	**5,447,441**
Capital expenditures	**243,151**	**110,914**	**60,235**	**26,853**	**10,357**	**451,510**	**26,764**	**3,153**	**16,887**	**1,676**	**–**	**499,990**
Year ended December 31, 2005 *(in thousands of dollars)*												
Operating revenues	259,775	194,765	419,963	116,693	139,668	1,130,864	75,790	83,955	154,403	9,977	(24,984)	1,430,005
Equity income	–	–	–	–	–	–	11,466	–	–	–	–	11,466
Energy supply costs	–	60,412	255,954	71,568	110,164	498,098	40,845	6,204	–	–	(11,232)	533,915
Operating expenses	113,006	64,738	53,812	12,535	14,520	258,611	10,725	17,812	99,967	9,490	(4,225)	392,380
Amortization	61,395	19,038	32,143	9,670	5,100	127,346	5,770	10,380	11,244	2,882	–	157,622
Operating income	85,374	50,577	78,054	22,920	9,884	246,809	29,916	49,559	43,192	(2,395)	(9,527)	357,554
Finance charges	24,198	18,513	31,369	7,614	5,058	86,752	5,614	14,051	19,988	36,947	(9,527)	153,825
Gain on settlement of contractual matters	–	–	–	–	–	–	–	(10,000)	–	–	–	(10,000)
Corporate taxes	25,105	7,424	15,368	6,224	493	54,614	1,261	13,811	9,077	(8,347)	–	70,416
Non-controlling interest	–	–	588	–	–	588	3,610	2,183	–	(165)	–	6,216
Net earnings (loss) applicable to common shares	36,071	24,640	30,729	9,082	4,333	104,855	19,431	29,514	14,127	(30,830)	–	137,097
Goodwill	228,615	220,719	–	19,858	42,947	512,139	–	–	–	–	–	512,139
Identifiable assets	970,738	722,392	895,892	290,356	120,867	3,000,245	212,157	267,049	427,753	41,655	(28,702)	3,920,157
Equity investment assets	–	–	–	–	–	–	164,808	–	–	–	–	164,808
Total assets	1,199,353	943,111	895,892	310,214	163,814	3,512,384	376,965	267,049	427,753	41,655	(28,702)	4,597,104
Capital expenditures	164,962	115,989	55,399	40,369	10,913	387,632	15,197	19,310	21,275	2,615	–	446,029

[(1)] Includes Belize Electricity, Fortis Turks and Caicos, and Caribbean Utilities in Grand Cayman.

December 31, 2006 and 2005

24. b) Inter-Segment Transactions

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the year were as follows:

(in thousands)	**2006**	2005
Sales from Fortis Generation to Belize Electricity	**$ 16,629**	$ 8,217
Sales from Fortis Generation to FortisOntario	**1,481**	2,032
Sales from Newfoundland Power to Fortis Properties	**3,422**	3,474
Inter-segment finance charges on borrowings from:		
Corporate to Fortis Properties	**4,751**	3,763
Corporate to Fortis Generation	**–**	2,222
Fortis Generation to Belize Electricity	**742**	2,266

25. Supplementary Information to Consolidated Statements of Cash Flows

(in thousands)	**2006**	2005
Interest paid	**$ 160,931**	$ 146,687
Income taxes paid	**$ 54,498**	$ 38,281

26. Financial Instruments

Fair Values

Fair value estimates are made as of a specific point in time using available information about the financial instruments and current market conditions. The estimates are subjective in nature involving uncertainties and significant judgment.

The carrying values of financial instruments included in current assets and current liabilities in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity and normal trade credit terms of these instruments. The fair value of the long-term debt and capital lease obligations is estimated using present value techniques based on current pricing of financial instruments with comparable terms. Since the Corporation does not intend to settle the debt prior to maturity, the fair value estimate does not represent an actual liability and therefore does not include exchange or settlement costs. The fair value of preference shares is determined using quoted market prices. The fair value of interest rate swap contracts reflects the estimated amount that the Corporation would have to pay if forced to settle all outstanding contracts at year end. This fair value reflects a point-in-time estimate that may not be relevant in predicting the Corporation's future earnings or cash flows.

The carrying and fair values of the Corporation's long-term debt and capital lease obligations, preference shares and interest rate swap contracts as at December 31st were as follows.

	2006		2005	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Long-term debt and capital lease obligations *(Note 11)*	**$ 2,643.2**	**$ 2,968.6**	$ 2,167.1	$ 2,492.6
Preference shares *(Note 14)* [(1)]	**442.0**	**483.9**	319.5	369.1
Interest rate swap contracts	**–**	**(0.5)**	–	(0.9)

[(1)] Includes preference shares classified as both equity and long-term liabilities

Risk Management

The Corporation has exposure to foreign currency exchange rate fluctuations associated with its US dollar-denominated operations. The Corporation may periodically enter into hedges of its foreign currency exposures on its foreign net investments by entering into offsetting forward exchange contracts and through the use of US dollar borrowings. The Corporation does not hold or issue derivative financial instruments for trading purposes.

The Corporation's earnings from its foreign net investments are exposed to changes in US dollar exchange rates. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with earnings from its foreign net investments through the use of US dollar borrowings.

Prior to the acquisition of Fortis Turks and Caicos in August 2006 and controlling interest in Caribbean Utilities in November 2006, the Corporation's earnings were impacted by foreign currency exchange rate fluctuations associated with the translation of US dollar borrowings not designated as a hedge against the Corporation's foreign net investments. Immediately prior to the acquisition of Fortis Turks and Caicos, Fortis had US$32 million (December 31, 2005 – US$55 million) of US dollar borrowings in excess of the Corporation's foreign net investments, which did not qualify for hedge accounting. Consequently, fluctuations in the carrying value of this debt, resulting from foreign currency exchange rate fluctuations, were recorded in earnings in each reporting period. The Corporation recorded an unrealized foreign exchange gain of $2.1 million up to August 2006 on US dollar borrowings not in a hedging relationship.

The Corporation's foreign net investments increased upon the acquisition of Fortis Turks and Caicos, thereby allowing the US$32 million and the incremental US dollar borrowings associated with the acquisition of Fortis Turks and Caicos to be designated as a hedge against this foreign net investment. The US dollar debt associated with the acquisition of a controlling interest in Caribbean Utilities qualified for hedge accounting and was designated as a hedge against this foreign net investment. Previously, the Corporation's equity accounted investment in Caribbean Utilities did not qualify for hedge accounting purposes as a foreign net investment. As at December 31, 2006, all of the Corporation's US$258.6 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's US dollar borrowings designated as hedges are recorded in the Corporation's foreign currency translation adjustment account in shareholders' equity. As at December 31, 2006, the Corporation had approximately US$121 million in foreign net investments available to be hedged.

Interest Rate Risk

Long-term debt is primarily issued at fixed interest rates, thereby minimizing cash flow and interest rate exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings and other variable interest credit facilities. The Corporation designates its interest rate swap contracts as hedges of the underlying debt. Interest expense on the debt is adjusted to include payments made or received under the interest rate swaps.

Credit Risk

The Corporation is exposed to credit risk in the event of non-performance by counterparties to its derivative financial instruments. Non-performance is not anticipated since these counterparties are highly rated financial institutions. In addition, the Corporation is exposed to credit risk from customers. However, the Corporation has a large and diversified customer base, which minimizes the concentration of this risk.

Rate Regulation

Certain of the Corporation's regulated utilities have rate stabilization accounts, which are approved by the regulators, to recover excess energy costs over an established benchmark. These accounts minimize the impact of changing energy costs on the financial results of the Corporation.

December 31, 2006 and 2005

27. Commitments

(in millions)	**Total**	< 1 year	1–3 years	4–5 years	> 5 years
Power purchase obligations					
FortisBC (1)	**$ 2,884.6**	$ 38.6	$ 74.1	$ 76.0	$ 2,695.9
FortisOntario (2)	**310.7**	21.9	42.7	44.5	201.6
Maritime Electric (3)	**38.7**	30.1	8.6	–	–
Belize Electricity (4)	**20.2**	2.7	3.4	2.3	11.8
Capital cost (5)	**426.5**	15.7	27.9	35.4	347.5
Joint-use asset and shared service agreements (6)	**64.5**	3.8	7.7	6.7	46.3
Office lease – FortisBC (7)	**21.7**	1.1	2.6	2.4	15.6
Caribbean Utilities (8)	**19.2**	7.7	11.5	–	–
Operating lease obligations (9)	**18.0**	4.5	7.6	5.2	0.7
Other	**1.4**	0.1	0.1	0.1	1.1
Total	**$ 3,805.5**	$ 126.2	$ 186.2	$ 172.6	$ 3,320.5

(1) Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric plant located near Castlegar, British Columbia. The BPPA requires monthly payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(2) Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing, which expires June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at $0.14 million per month.

(3) Maritime Electric has one take-or-pay contract for the purchase of either capacity or energy. This contract totals approximately $38.7 million through March 31, 2008.

(4) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity, which commenced in February 2007, and a two-year power purchase agreement between Belize Electricity and Comisión Federal de Electricidad of Mexico, expiring August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen") that provides for the supply of approximately 14 MW of capacity, which is scheduled to commence in mid-2009. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.

(5) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(6) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2011 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

(7) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years (Note 4 *(xii)*). The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term. On December 1, 2004, FortisBC also entered into a five-year lease for the Kelowna, British Columbia head office. The terms of the lease allow for termination without penalty after three years.

(8) During 2006, Caribbean Utilities entered into a project agreement for the purchase and turnkey installation of one 16 MW medium-speed diesel generating unit and auxiliary equipment. This unit is scheduled for installation to meet the summer 2007 energy demand. The contract cost is US$18.4 million, and the total estimated cost for completion of the project is US$22.2 million. As at October 31, 2006, approximately US$5.7 million had been spent by Caribbean Utilities on this project.

(9) Operating lease obligations include certain office, vehicle and equipment leases and the lease of electricity distribution assets of Port Colborne Hydro Inc.

The regulated subsidiaries of the Corporation are obligated to provide service to customers within their respective service territories. These regulated subsidiaries' capital expenditures are largely driven by customer requests or include large capital projects specifically approved by their respective regulators. The consolidated capital program of the Corporation, including non-regulated segments, is forecast to include approximately $623 million in capital expenditures for 2007. This commitment has not been included in the summary table shown above.

28. Contingent Liabilities

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

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

(a) **Maritime Electric**

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the Point Lepreau Station in 1998.

Maritime Electric believes it has reported its tax position appropriately in all aspects of the reassessment and filed a Notice of Objection with the Chief of Appeals at CRA. Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $12.1 million in taxes and accrued interest. As at December 31, 2006, Maritime Electric has provided for, through future and current income taxes payable, approximately $11.6 million and, therefore, an additional liability of $0.5 million would arise. In this event, the Company would apply to IRAC to include this amount in the regulatory rate-making process. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA and the Company made a payment on deposit of $5.9 million with CRA on June 29, 2006.

December 31, 2006 and 2005

28. Contingent Liabilities (cont'd)

(b) **FortisAlberta**

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately $2.7 million in fire-fighting and suppression costs and approximately $2.4 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date leads management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, given the preliminary stage of the proceedings, FortisAlberta has not made any definitive assessment of potential liability with respect to the claim. No amount, therefore, has been accrued in the consolidated financial statements.

(c) **FortisBC**

The B.C. Ministry of Forests (the "Ministry") 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. The Company is currently communicating with the Ministry and its insurers. In addition, FortisBC has been served with two filed writs and statements of claim by private land owners in relation to this matter. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

On January 5, 2006, FortisBC was served with a writ and statement of claim filed with the B.C. Supreme Court under the *Class Proceedings Act, 1995* (British Columbia) on behalf of a class consisting of all persons who are or were customers of FortisBC and who paid or have been charged FortisBC's late payment penalties at any time between April 1, 1981 and the date of any judgment in this action. The claim is that forfeitures of the prompt payment discount offered to customers constitute "interest" within the meaning of section 347 of the *Criminal Code* (Canada) and, since the effective annual rate of such interest exceeds 60 per cent, they are illegal and void. In the action, the Plaintiff seeks damages and restitution of all late payment penalties that were forfeited. On December 13, 2006, the application to certify the action as a class action was heard in the B.C. Supreme Court. In a decision delivered on January 11, 2007, the B.C. Supreme Court dismissed the application to certify the action as a class suit. The Plaintiff has filed an appeal of the decision with the B.C. Court of Appeal. The final outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

(d) **FortisUS Energy**

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the "Village"), New York. The Village 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 hydro site, located in the Village of Philadelphia municipality, now owned by FortisUS Energy, totalling approximately US$7.1 million (CDN$8.0 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. The Village, however, filed a notice of appeal in January 2007. Management believes that the appeal will not be successful and, therefore, no provision has been made in the consolidated financial statements.

29. Subsequent Events

(a) On January 3, 2007, FortisAlberta closed a $110 million senior unsecured debenture offering. The debentures bear interest at a rate of 4.99 per cent, to be paid semi-annually, and mature on January 3, 2047. The proceeds of the offering were used to repay existing indebtedness incurred under the Company's committed unsecured credit facility, which was incurred primarily to fund capital expenditures, and for general corporate purposes.

(b) On January 18, 2007, Fortis issued 5,170,000 Common Shares for $29.00 per common share. The common share issue resulted in gross proceeds of $149.9 million, or approximately $145.6 million net of after-tax expenses. The net proceeds of the offering were used to repay indebtedness incurred for recent acquisitions, to support the capital expenditure programs of the Corporation's regulated utilities in Western Canada and for general corporate purposes.

(c) On February 8, 2007, Fortis announced that its Board of Directors had declared a 10.5 per cent increase in the quarterly common share dividend, increasing the amount from 19 cents per common share to 21 cents per common share, commencing with the second quarter dividend payable on June 1, 2007, to shareholders of record on May 4, 2007.

(d) On February 26, 2007, Fortis entered into an agreement (the "Acquisition Agreement") with 3211953 Nova Scotia Company and Kinder Morgan, Inc. ("Kinder Morgan") (NYSE:KMI), a U.S. energy transportation, storage and distribution company based in Houston, Texas, for the purchase (the "Acquisition") of all the issued and outstanding shares of Terasen Inc. for aggregate consideration of $3.7 billion, including the assumption of approximately $2.3 billion of consolidated indebtedness of Terasen Inc. Terasen Inc. is a holding company headquartered in Vancouver, British Columbia, operating two principal lines of business – natural gas distribution and petroleum transportation. Prior to the closing of the Acquisition, Kinder Morgan will cause Terasen Inc. to divest itself of its petroleum transportation operations. The closing of the Acquisition, which is expected to occur in mid-2007, is subject to receipt of required regulatory and other approvals, including that of the BCUC, and the satisfaction of certain closing conditions. Under the Acquisition Agreement, Kinder Morgan or Fortis may elect to terminate the Acquisition Agreement if the Acquisition is not completed prior to November 30, 2007.

To finance a portion of the Acquisition, Fortis entered into an agreement on February 27, 2007 with CIBC World Markets Inc., Scotia Capital Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., National Bank Financial Inc., Canaccord Capital Corporation, Beacon Securities Limited and HSBC Securities (Canada) Inc. (collectively the "Underwriters") pursuant to which they agreed to purchase from Fortis and sell to the public 38,500,000 Subscription Receipts of the Corporation for a purchase price of $26.00 per Subscription Receipt. The Underwriters also had the option to purchase up to an additional 5,775,000 Subscription Receipts at the purchase price of $26.00 per Subscription Receipt to cover over-allotments, if any, at any time until 30 days following the closing of the Subscription Receipt offering. The gross proceeds from the sale of Subscription Receipts of $1,001,000,000 ($1,151,150,000 if the Over-Allotment Option is exercised in full) will be held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the Acquisition and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition (collectively, the "Release Conditions"). Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions, and without payment of additional consideration, one Common Share of Fortis and a cash payment equal to the dividends declared on Fortis Common Shares to holders of record during the period from the closing of the Subscription Receipt offering to the date of issuance of the Common Shares in respect of the Subscription Receipts. In the event that the Release Conditions are not satisfied by November 30, 2007, or if the Acquisition Agreement is terminated prior to such time, the holders of Subscription Receipts will be entitled to receive an amount equal to the full subscription price thereof plus their pro rata share of the interest earned or income generated on such amount. On March 15, 2007, the Subscription Receipt offering closed, the Underwriters exercised the Over-Allotment Option and therefore $1,151,150,000 was placed into escrow.

Fortis has also obtained a commitment from Canadian Imperial Bank of Commerce providing for an aggregate of $1.425 billion non-revolving term credit facilities in favour of Fortis to fund, if necessary, the full cash purchase price for the Acquisition. The net proceeds from the Subscription Receipt offering and funds to be advanced under the acquisition credit facilities will be used to finance the cash portion of the acquisition purchase price.

30. Comparative Figures

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

HISTORICAL FINANCIAL SUMMARY

Statements of Earnings *(in thousands $)*	**2006**[1]	2005[1]	2004	2003
Revenue, including equity income	**1,471,736**	1,441,471	1,146,129	843,080
Energy supply costs and operating expenses	**939,072**	926,295	766,628	578,731
Amortization	**177,511**	157,622	113,672	62,327
Finance charges	**168,329**	153,825	122,373	86,287
Gain on settlement of contractual matters	**–**	10,000	–	–
Corporate taxes	**32,538**	70,416	46,927	38,236
Results of discontinued operations, gains on sales and other unusual items	**2,088**	–	–	–
Non-controlling interest	**7,602**	6,216	5,674	3,869
Preference share dividends	**1,585**	–	–	–
Net earnings applicable to common shares	**147,187**	137,097	90,855	73,630
Balance Sheets *(in thousands $)*				
Current assets	**409,139**	299,274	293,423	191,032
Other long-term assets, including goodwill	**991,931**	815,436	768,077	242,320
Long-term investments	**2,536**	167,393	163,769	167,752
Utility capital assets and income producing properties	**4,043,835**	3,315,001	2,712,747	1,562,693
Total assets	**5,447,441**	4,597,104	3,938,016	2,163,797
Current liabilities	**565,254**	412,298	538,258	296,056
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**475,625**	476,672	138,198	61,956
Long-term debt and capital lease obligations	**2,558,463**	2,135,674	1,904,431	1,031,358
Non-controlling interest	**130,505**	39,555	37,487	36,770
Preference shares (classified as debt)	**319,492**	319,492	319,530	122,992
Shareholders' equity	**1,398,102**	1,213,413	1,000,112	614,665
Cash Flows *(in thousands $)*				
Operations	**263,137**	303,585	272,268	156,682
Financing activities	**454,986**	224,088	777,044	232,011
Investing activities	**634,082**	467,104	1,026,256	308,006
Dividends, excluding dividends on preference shares classified as debt	**76,624**	64,171	50,514	38,456
Financial Statistics				
Return on average common shareholders' equity *(%)*	**11.87**	12.40	11.28	12.30
Capitalization Ratios *(%)* (year end)[2]				
Total debt and capital lease obligations (net of cash)	**61.1**	58.7	61.4	60.0
Preference shares (classified as debt and equity)	**10.0**	8.6	9.4	6.7
Common shareholders' equity	**28.9**	32.7	29.2	33.3
Interest Coverage *(x)*				
Debt	**2.2**	2.5	2.3	2.2
All fixed charges	**2.0**	2.1	2.0	2.1
Capital expenditures *(in thousands $)*	**499,990**	446,029	278,669	207,740
Common share data				
Book value per share (year end) *($)*	**12.19**	11.74	10.45	8.82
Average common shares outstanding *(in thousands)*	**103,578**	101,750	84,738	69,236
Earnings per common share *($)*	**1.42**	1.35	1.07	1.06
Dividends declared per common share *($)*	**0.700**	0.605	0.548	0.525
Dividends paid per common share *($)*	**0.670**	0.588	0.540	0.520
Dividend payout ratio *(%)*	**47.2**	43.7	50.3	48.9
Price earnings ratio *(x)*	**21.0**	18.0	16.2	13.9
Share trading summary				
Closing price *($)* (TSX)	**29.77**	24.27	17.38	14.73
Volume *(in thousands)*	**60,094**	37,706	29,254	31,180

[1] As at December 31, 2006, the regulatory provision for future site removal and restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets.

[2] Comparative capitalization ratios have been restated to comply with the current year's calculation methodology.

2002	2001	2000	1999	1998	1997	1996
715,465	628,254	580,197	505,218	472,725	486,662	474,293
476,969	418,117	417,607	356,227	339,429	341,024	334,388
65,063	62,495	52,513	45,407	42,428	41,147	35,993
73,464	65,630	55,712	46,065	43,637	44,890	45,812
–	–	–	–	–	–	–
32,488	28,732	17,228	27,476	22,998	29,449	28,029
–	4,179	2,771	(57)	3,696	369	–
4,229	3,862	3,149	803	515	515	1,026
–	–	–	–	–	–	–
63,252	53,597	36,759	29,183	27,414	30,006	29,045
180,122	134,935	165,814	92,862	94,123	78,603	70,456
204,837	123,011	116,912	160,998	162,487	160,445	160,470
95,751	82,211	81,515	–	–	–	–
1,459,300	1,245,940	1,056,291	929,909	750,223	747,461	736,338
1,940,010	1,586,097	1,420,532	1,183,769	1,006,833	986,509	967,264
334,467	272,439	224,431	229,569	147,764	172,158	172,493
–	–	–	15,640	15,745	20,444	17,448
38,835	31,628	24,110	27,538	21,942	23,307	23,388
940,910	746,092	678,349	487,828	424,275	385,627	335,654
39,955	36,419	31,502	29,381	8,430	8,430	8,430
–	50,000	50,000	50,000	50,000	50,000	100,000
585,843	449,519	412,140	343,813	338,677	326,543	309,851
134,422	94,115	97,499	84,679	68,898	63,202	86,351
261,043	171,358	177,820	66,797	15,858	16,721	33,992
348,724	239,726	240,698	122,469	65,882	54,093	95,838
35,070	29,913	27,661	24,303	23,824	22,968	22,416
12.23	12.44	9.73	8.55	8.24	9.43	9.61
65.2	63.9	60.4	59.6	53.4	53.6	48.4
–	3.6	4.3	5.1	6.0	6.2	12.6
34.8	32.5	35.3	35.3	40.6	40.2	39.0
2.3	2.3	2.1	2.3	2.2	2.6	2.6
2.2	2.2	1.9	2.1	2.0	2.0	1.9
228,830	149,455	157,652	86,475	65,468	49,773	53,420
8.50	7.50	6.97	6.55	6.52	6.40	6.21
65,108	59,512	54,068	52,188	51,632	50,492	49,276
0.97	0.90	0.68	0.56	0.53	0.60	0.59
0.498	0.470	0.460	0.455	0.450	0.443	0.430
0.485	0.468	0.460	0.453	0.450	0.440	0.430
49.9	51.9	67.6	80.8	84.9	73.9	72.9
13.5	13.0	13.2	14.0	18.0	17.6	14.4
13.13	11.74	9.00	7.85	9.56	10.50	8.50
21,676	21,460	26,760	9,024	12,356	13,520	13,620

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

FortisAlberta Inc.

Directors: H. Stanley Marshall (Chair), Donald G. Bacon, Brian F. Bietz, Gregory E. Conn, Al H. Duerr, Philip G. Hughes, Joanne R. Lemke, John S. McCallum, Barry V. Perry, John C. Walker

Officers:
Philip G. Hughes, President and Chief Executive Officer
D. James Harbilas, Vice President, Finance and Chief Financial Officer
Karin C. F. Gashus, Vice President, Customer Service
Cynthia Johnston, Vice President, Corporate Services and Regulatory
Alan M. Skiffington, Vice President, Information Technology and CIO
Gary J. Smith, Vice President, Operations and Engineering
Mike G. Olson, Controller and Treasurer
Robert J. Fink, Corporate Counsel and Corporate Secretary
Karl J. Bomhof, Corporate Counsel and Assistant Secretary

FortisBC Inc.

Directors: R. Harry McWatters (Chair), Beth D. Campbell, Richard (Kim) D. Deane, E. Walter Gray, Philip G. Hughes, H. Stanley Marshall, Roger Mayer, John S. McCallum, Barry V. Perry, John C. Walker

Officers:
John C. Walker, President and Chief Executive Officer
Michele I. Leeners, Vice President, Finance and Chief Financial Officer
Don L. Debienne, Vice President, Generation
Michael A. Mulcahy, Vice President, Customer and Corporate Services
Doyle O. Sam, Vice President, Transmission and Distribution
David C. Bennett, Vice President, Regulatory Affairs and General Counsel

Newfoundland Power Inc.

Directors: David G. Norris (Chair), Trevor Adey, Peggy Bartlett, Bruce Chafe, William J. Daley, Ed Drover, Peter W. Fenwick, Chris Griffiths, Georgina Hedges, H. Stanley Marshall, Karl W. Smith, John C. Walker

Officers:
Karl W. Smith, President and Chief Executive Officer
Jocelyn H. Perry, Vice President, Finance and Chief Financial Officer
Lisa A. Hutchens, Vice President, Customer Relations and Corporate Services
Phonse J. Delaney, Vice President, Engineering and Operations
Peter S. Alteen, Vice President, Regulatory Affairs and General Counsel

Maritime Electric Company, Limited

Directors: L. John Reddin (Chair), Harry D. Annear, Ronald J. Keefe, Earl A. Ludlow, R. Elmer MacDonald, H. Stanley Marshall, Fred J. O'Brien, Cheryl L. Paynter, Barbara F. Stephenson, Lynn R. Young

Officers:
Fred J. O'Brien, President and Chief Executive Officer
J. William Geldert, Vice President, Finance, CFO and Corporate Secretary
John D. Gaudet, Vice President, Corporate Planning and Energy Supply
Steve D. Loggie, Vice President, Customer Service

FortisOntario Inc.

Directors: Gilbert S. Bennett (Chair), Peter E. Case, William J. Daley, Geoffrey F. Hyland, James A. Lea, H. Stanley Marshall, Oskar T. Sigvaldason, Karl W. Smith

Officers:
William J. Daley, President and Chief Executive Officer
Glen C. King, Vice President, Finance and Chief Financial Officer
Angus S. Orford, Vice President, Operations
R. Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary

Belize Electricity Limited

Directors: Robert Usher (Chair), J. F. Richard Hew, Philip G. Hughes, James A. Lea, H. Stanley Marshall, Karl H. Menzies, Dylan Reneau, Yasin Shoman, Lynn R. Young

Officers:
Lynn R. Young, President and Chief Executive Officer
Rene J. Blanco, Vice President, Finance & Administration and CFO
Felix J. Murrin, Vice President, Customer Care and Operations
Joseph Sukhnandan, Vice President, Engineering and Energy Supply
Juliet Estell, Manager, Executive Services and Company Secretary

Caribbean Utilities Company, Ltd.

Directors: David E. Ritch (Chair), Frank J. Crothers (Vice Chair), Philip A. Barnes, J. Bryan Bothwell, Sheree L. Ebanks, J. F. Richard Hew, Philip G. Hughes, Joseph A. Imparato, H. Stanley Marshall, Peter A. Thomson, Anna Rose S. Washburn

Officers:
J. F. Richard Hew, President and Chief Executive Officer
Eddinton M. Powell, Senior VP, Finance & Corporate Services and CFO
Andrew E. Small, Vice President, Production
J. Lee Tinney, Vice President, Transmission and Distribution
Robert D. Imparato, Company Secretary and Chief Governance Officer

Fortis Turks and Caicos

Directors: H. Stanley Marshall, Barry V. Perry, Ronald W. McCabe

Officers:
H. Stanley Marshall, President
Barry V. Perry, Vice President
Ronald W. McCabe, Company Secretary

Fortis Properties Corporation

Directors: Linda L. Inkpen (Chair), Bruce Chafe, Earl A. Ludlow, H. Stanley Marshall, David G. Norris

Officers:
Earl A. Ludlow, President and Chief Executive Officer
Neal J. Jackman, Vice President, Finance and Chief Financial Officer
Nora M. Duke, Vice President, Hospitality Services
Wayne W. Myers, Vice President, Real Estate
Ronald W. McCabe, General Counsel and Corporate Secretary

Bruce Chafe ∗ ★ ✷
Chair, Fortis Inc., St. John's, Newfoundland and Labrador

Mr. Chafe, 70, joined the Fortis Inc. Board in 1997 and was appointed Chair of the Board in May 2006. He is past Chair of the Audit Committee of the Board. Mr. Chafe has been a director of Fortis Properties Corporation since 1997. He has served on the Boards of Newfoundland Power Inc. and FortisBC Inc. Mr. Chafe is also a Director of several private investment firms. He is a retired senior partner of Deloitte & Touche LLP.

Peter E. Case ∗
Corporate Director, Freelton, Ontario

Mr. Case, 52, joined the Fortis Inc. Board in May 2005. He has been a consultant to the utility industry since 2003, following his retirement as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Geoffrey F. Hyland ✷
Corporate Director, Caledon, Ontario

Mr. Hyland, 62, joined the Fortis Inc. Board in May 2001. He retired as President and CEO of ShawCor Ltd. in June 2005. 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 ★
Medical Practitioner, St. John's, Newfoundland and Labrador

Dr. Inkpen, 59, joined the Fortis Inc. Board in 1994. She was appointed Chair of the Board of Fortis Properties Corporation in 2000 and is a past Chair of Newfoundland Power Inc.

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

Mr. Marshall, 56, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis companies and is a Director of Toromont Industries Ltd.

John S. McCallum ∗ ★
Professor of Finance, University of Manitoba, Winnipeg, Manitoba

Mr. McCallum, 63, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

David G. Norris ∗ ✷
Corporate Director, St. John's, Newfoundland and Labrador

Mr. Norris, 59, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ✷
Corporate Director, Moncton, New Brunswick

Mr. Pavey, 59, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with TransAlta Corporation. Mr. Pavey has served as a Director of Maritime Electric Company, Limited.

Roy P. Rideout ★ ✷
Corporate Director, Halifax, Nova Scotia

Mr. Rideout, 59, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited. He also serves as a Director of the Halifax International Airport Authority, Oceanex Inc. and NAV CANADA.

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

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

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplication, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan(1) and a Consumer Share Purchase Plan(2) to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional cash payments (minimum of $100, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares are sold quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent, Computershare Trust Company of Canada.

(1) All registered shareholders of Common Shares who are residents of Canada are eligible to participate in the Dividend Reinvestment Plan. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.

(2) The Consumer Share Purchase Plan is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.

Valuation Day

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

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

Share Listings

The Common Shares, First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and Subscription Receipts of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.R, respectively.

Common Share Prices

Year	High	Low	Close
2006	30.00	20.36	29.77
2005	25.64	17.00	24.27
2004	17.75	14.23	17.38
2003	15.24	11.63	14.73
2002	13.28	10.76	13.13
2001	11.89	8.56	11.74
2000	9.19	6.88	9.00
1999	9.93	7.29	7.85
1998	12.03	8.75	9.56
1997	10.63	7.83	10.50

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Design and Production:
CCL Group – Colour, St. John's, NL
Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

Expected Dividend* and Earnings Dates

Dividend Record Date

May 4, 2007	August 10, 2007
November 9, 2007	February 8, 2008

Dividend Payment Dates

June 1, 2007	September 1, 2007
December 1, 2007	March 1, 2008

Earnings Release Dates

May 3, 2007	August 3, 2007
November 2, 2007	February 6, 2008

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

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 8, 2007
10:30 a.m.
Delta St. John's
120 New Gower Street
St. John's, NL Canada

Photography:

Cover: Wayne Duchart, Kelowna, BC (wayne@photographywest.ca)
Jack LeClair, Charlottetown, PE
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Ned Pratt, St. John's, NL
Neil Murray, Grand Cayman, KY
Denise Vanzie, Belize City, BZ
Doug Greenslade, St. John's, NL
Chris Hammond, St. John's, NL
Marnie Burkhart, Calgary, AB
Danny Foster, Kelowna, BC
Lee Ann Surette, St. John's, NL
Bobb Barratt, Niagara Falls, ON
Courtney Bonita, Fort Erie, ON
Richard Holder, Belize City, BZ
Miguel Escalante, Grand Cayman, KY
Ron Kidd, Providenciales, TCI
Gerry Boland, St. John's, NL
John Woods, Belize City, BZ
Larry Doell, Trail, BC
Peter Robbins, Grand Falls-Windsor, NL
Howard Cabral, San Ignacio, BZ
Monty Hunter, St. John's, NL
Dawn Sampson, Belize City, BZ
Gail Tucker, St. John's, NL

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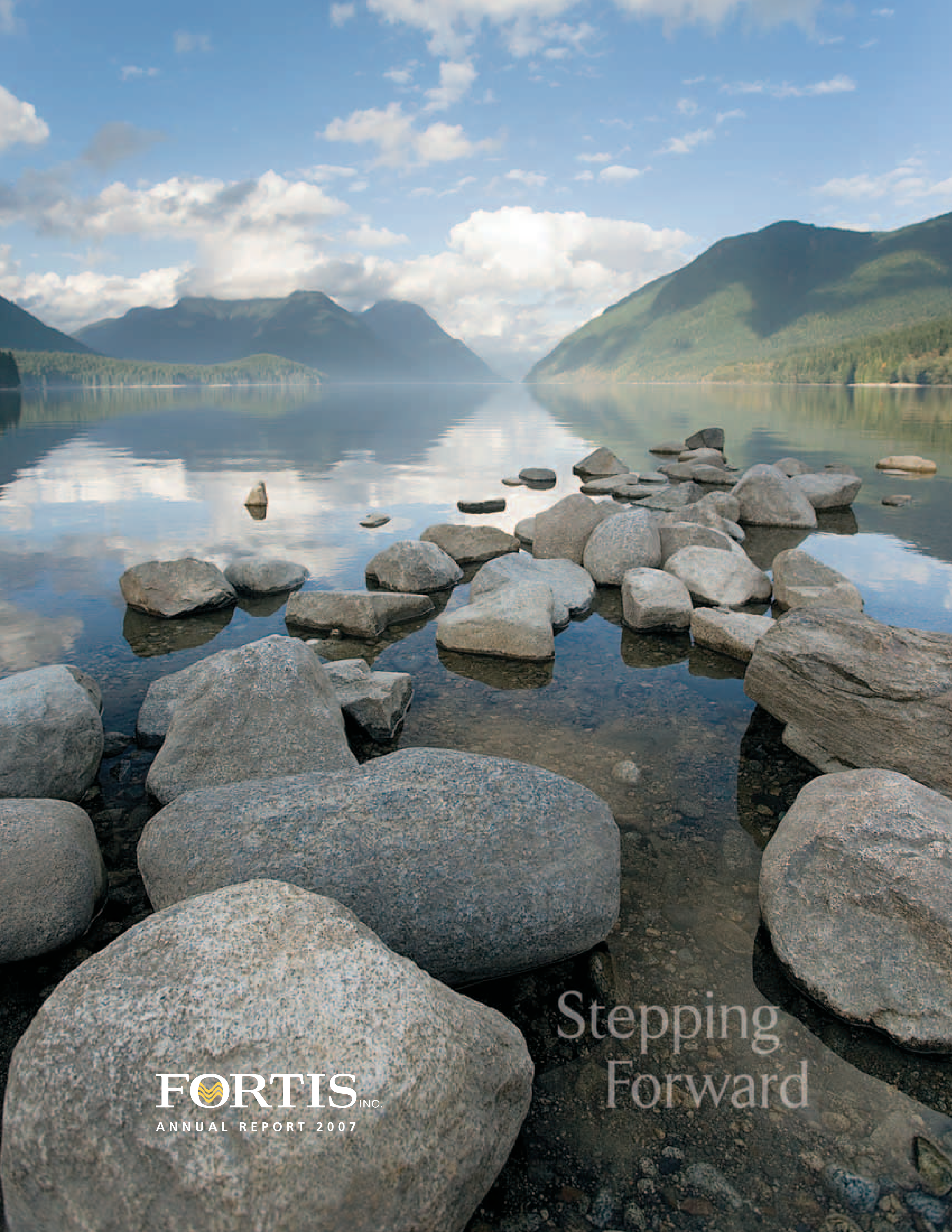
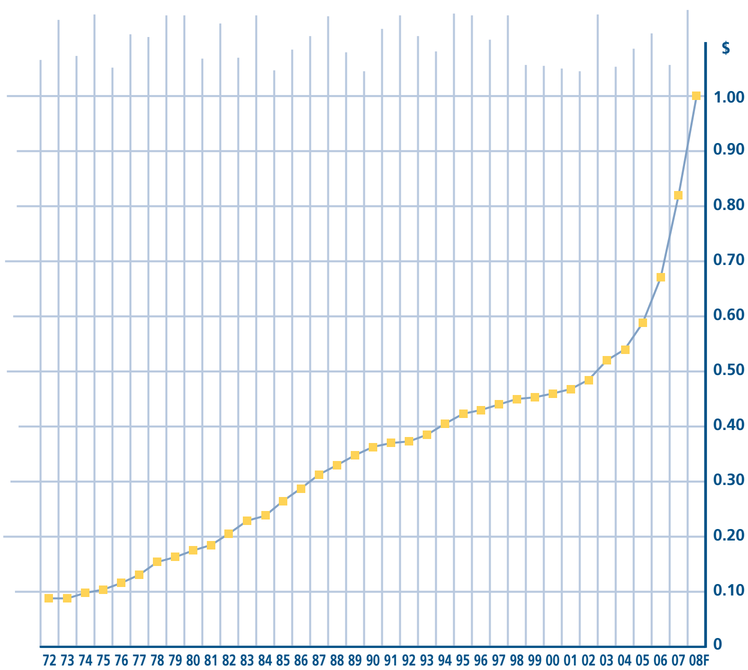
Fortis Inc.
2007 Annual Report


Stepping
Forward
FORTIS INC.
ANNUAL REPORT 2007

Contents

STEPPING FORWARD

Dividends paid per common share



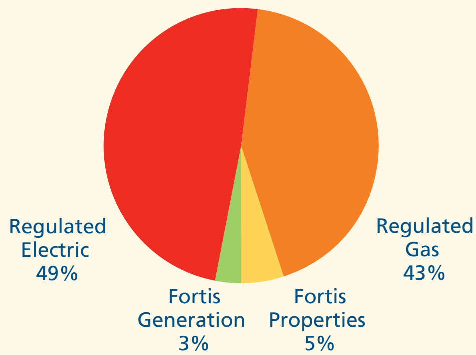
Fortis has increased its annual dividend to common shareholders for 35 consecutive years, the longest record of any public corporation in Canada.

Corporate Profile

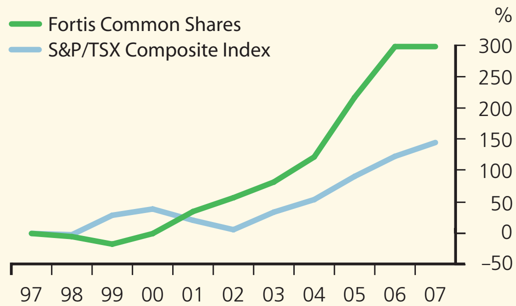
Fortis Inc. is the largest investor-owned distribution utility in Canada, serving almost 2,000,000 gas and electricity customers.

Total Assets Exceed $10 Billion

(as at December 31, 2007)



10-Year Cumulative Total Return



Regulated Utility Operations

Gas Operations

Terasen *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

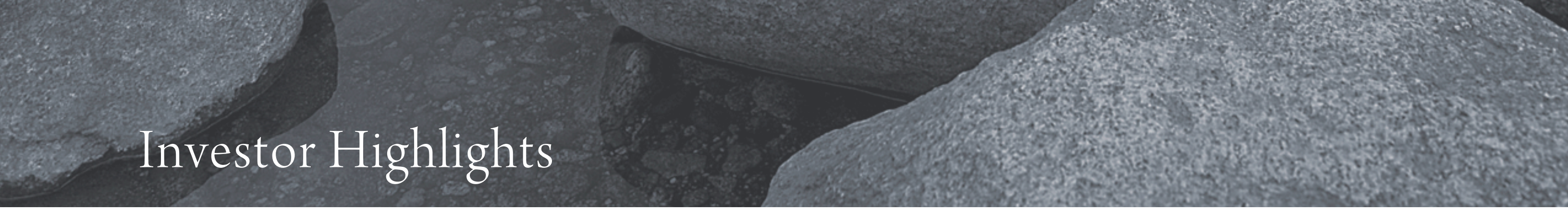
Fortis Generation

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

Fortis Properties

Real Estate
Atlantic Canada, Saskatchewan

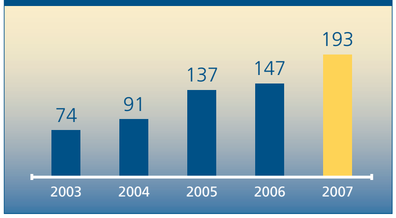
Hotels
Eastern Canada, Manitoba, Saskatchewan, Alberta, British Columbia



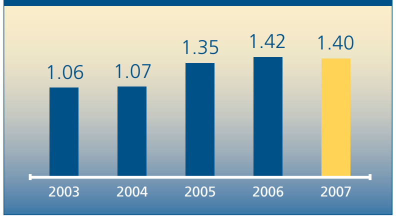
Investor Highlights

FIVE-YEAR PERFORMANCE

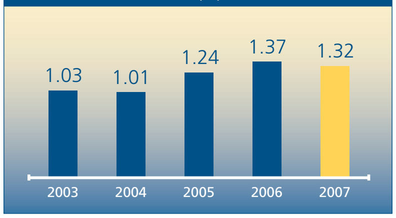
Earnings ($M)



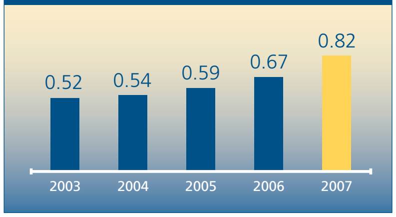
Basic Earnings per Common Share ($)



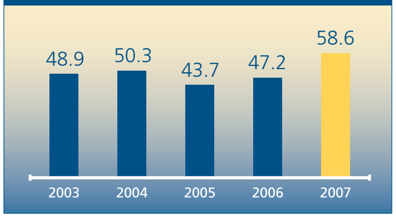
Diluted Earnings per Common Share ($)



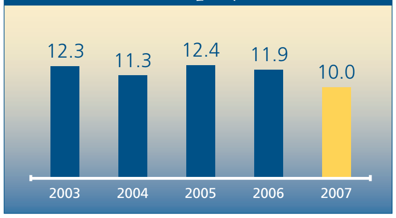
Dividends Paid per Common Share ($)



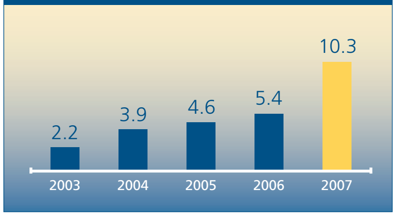
Dividend Payout Ratio (%)



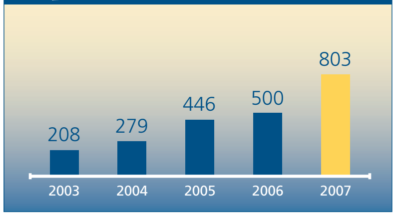
Return on Average Common Shareholders' Equity (%)



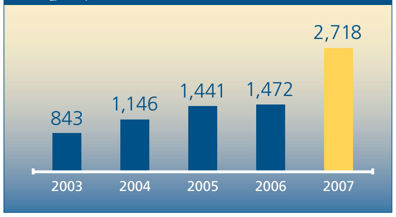
Assets ($B)



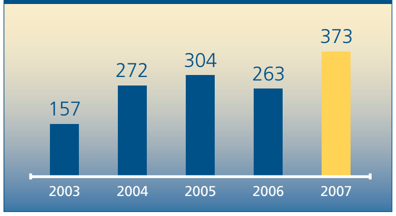
Capital Expenditures ($M)



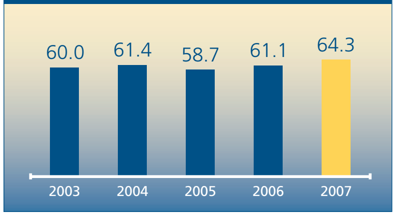
Revenue and Equity Income ($M)



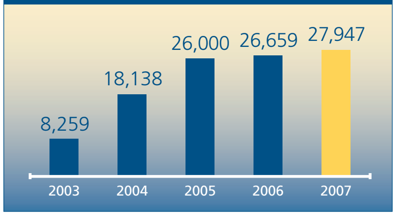
Cash Flow from Operations ($M)



Debt to Total Capitalization (%)

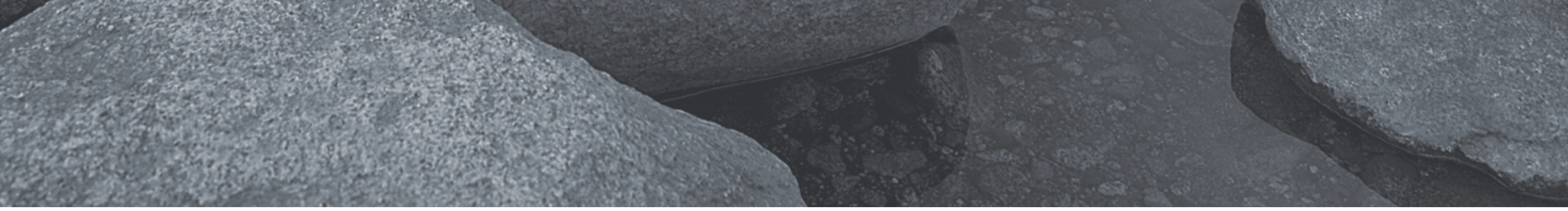


Electricity Sales and Deliveries (GWh)



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2007 unless otherwise indicated.



REGULATED

Gas

Terasen[1]	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Total Assets ($M)	Capital Program ($M)	Rate Base ($M)[2]	Earnings ($M)[3]	Allowed ROE (%)[4] 2007	2008
Total	**918,000**	**1,200**	**1,360**	**118**	**4,447**	**120**	**2,945**	**50**	**8.37**	**8.62**

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Total Assets ($M)	Capital Program ($M)	Rate Base ($M)[2]	Earnings ($M)[3]	Allowed ROE (%)[4] 2007	2008
FortisAlberta	448,000	999	3,182	15,378	1,521	285	1,129	48	8.51	8.75
FortisBC	154,000	532	683	3,091	1,135	147	823	31	8.77	9.02
Newfoundland Power	232,000	555	1,142	5,093	986	72	817	30	8.60	8.95
Maritime Electric	72,000	179	218	1,035	367	27	277	10	10.25	10.00
FortisOntario	52,000	124	234	1,174	180	11	111	6	9.00	9.00
Belize Electricity[5]	73,000	274	70	382	206	25	179	12	10.00–15.00[6]	10.00–15.00[6]
Caribbean Utilities[7]	23,000	193	93	527	448	56	320	9	15.00[6]	10.00[6][8]
Fortis Turks and Caicos	8,700	80	28	145	124	25	99	10	17.50[6]	17.50[6]
Total	**1,062,700**	**2,936**	**5,650**	**26,825**	**4,967**	**648**	**3,755**	**156**		

(1) Terasen primarily includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies". Gas volumes, capital program and earnings are from May 17, 2007, the date of acquisition.

(2) Forecast mid-year 2008

(3) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2007

(4) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.

(5) Fortis holds a 70.1% interest in Belize Electricity. Information in table represents 100% of Belize Electricity's operations except for earnings data.

(6) Regulated rate of return on rate base assets

(7) Fortis holds a 54% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations for the 12 months ended October 31, 2007, except for earnings data.

(8) As per proposed new licence expected to be issued during the first half of 2008.

NON-REGULATED

Fortis Generation[1]

	Generating Capacity (MW)	Energy Sales (GWh)	Assets[3] ($M)	Earnings[4] ($M)	Capital Program ($M)
Total	**195**	**1,122**	**324**	**24**	**22**

Fortis Properties[2]

	Employees (#)	Assets ($M)	Earnings[4] ($M)	Capital Program ($M)
Total	**1,800**	**535**	**24**	**13**

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

(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 19 hotels across Canada

(3) Includes $89 million in "Other" non-regulated assets

(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2007

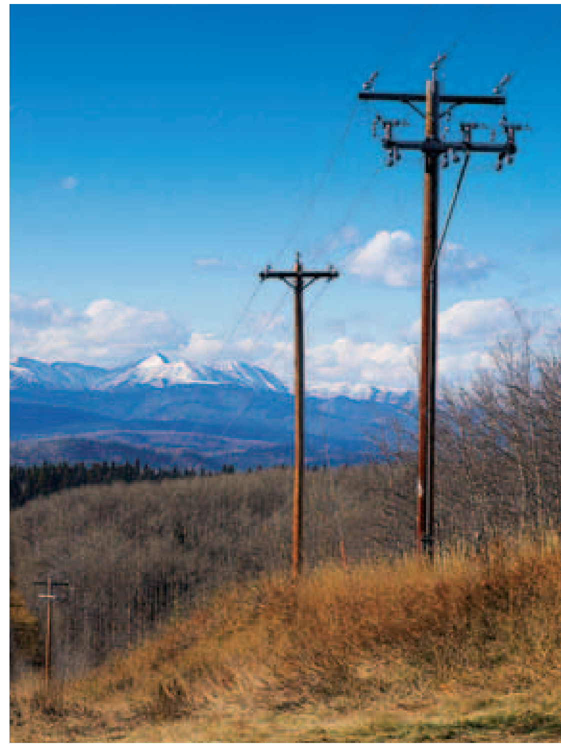
Information is for the fiscal year ended December 31, 2007 unless otherwise indicated.

Report to Shareholders

Fortis has delivered record earnings for the 8th consecutive year. It was also a year of record growth with our expansion into natural gas distribution through the acquisition of Terasen. The $3.7 billion acquisition doubled the Corporation's regulated rate base to approximately $6.3 billion and established Fortis as the largest investor-owned distribution utility in Canada.

Earnings applicable to common shares were $193 million in 2007, 31 per cent higher than earnings of $147 million last year. The growth in earnings was primarily attributable to the acquisition of Terasen in May, but also reflected the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. Earnings per common share were $1.40 compared to $1.42 in 2006. The Terasen acquisition diluted earnings per common share by approximately 7 cents in 2007 due to the seasonality of that company's earnings.

Building on our track record of dividend growth, dividends paid per common share grew to 82 cents in 2007, up 22 per cent from 67 cents the previous year. The dividend payout ratio was 58.6 per cent in 2007. Your Board of Directors increased the quarterly common share dividend to 25 cents from 21 cents, commencing with the first quarter dividend paid on March 1, 2008. The increase extends the Corporation's record of annual common share dividend increases to 35 consecutive years, the longest record of any public corporation in Canada. Growth in earnings has enabled Fortis to increase its quarterly common share dividend by 92 per cent since 2003.



Fortis electric utilities own and/or operate approximately 134,000 kilometres of transmission and distribution lines.

Stan Marshall, President and CEO, Fortis Inc. (left) and Bruce Chafe, Chair of the Board, Fortis Inc. (right)

In 2007, Fortis common shares reached a high of $30.00 and closed for the year at $28.99. Over the past five years, Fortis has delivered an average annualized total return of 20.9 per cent, exceeding the results of the S&P/TSX Composite Index and the S&P/TSX Utilities Index, which delivered average annualized total returns of 18.3 per cent and 17.2 per cent, respectively, over the same period.

Our common share market capitalization surpassed $4.5 billion in 2007, $1.4 billion higher than in 2006. The average daily trading volume of Fortis common shares exceeded 400,000 compared to 240,000 in 2006.

We expect the Terasen acquisition to be accretive to earnings per common share of Fortis over the first full year of our ownership. It is a well-managed company and one of the largest natural gas distributors in Canada, serving more than 918,000 customers or 96 per cent of gas users in British Columbia. Its integration within the Fortis Group of Companies is progressing well.

The appointment of a majority of independent directors to the Board of Directors of Terasen in November 2007 was a significant step, ensuring that Terasen operates consistent with the Fortis model, with its own board and management. We welcome our 1,200 Terasen employees to the Fortis Group and look forward to their contribution in building on our world-class reputation for operating efficient utilities and delivering quality customer service. Subsequent to the acquisition of Terasen, Standard & Poor's ("S&P") raised the unsecured debt credit rating of Fortis two notches to 'A–' from 'BBB'. The unsecured debt of Fortis is rated BBB (high) by DBRS.

The gas distribution business of Terasen, which is comprised of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., contributed $50 million to earnings since the acquisition in May. Because of its seasonal space-heating load, virtually all of the earnings of Terasen are generated in the first and fourth quarters.

In 2007, Fortis expanded into natural gas distribution through the acquisition of Terasen.

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these assets is 195 megawatts ("MW"), 190 MW of which is hydroelectric generation.

Report to Shareholders

Canadian Regulated Electric Utilities delivered $125 million in earnings, 10.6 per cent higher than earnings of $113 million in 2006. The increase was driven by additional investment in electrical infrastructure to meet customer growth at FortisAlberta and FortisBC but also reflected higher corporate income tax recoveries at FortisAlberta, rate increases at FortisBC and a one-time after-tax gain of approximately $2 million at FortisOntario.

Caribbean Regulated Electric Utilities contributed $31 million to earnings, $8 million higher than earnings in 2006, notwithstanding the impact of unfavourable foreign exchange rates associated with the strengthening Canadian dollar. Performance was enhanced by the first full year of earnings' contribution from Fortis Turks and Caicos, electricity sales growth at the three utilities and lower finance charges at Belize Electricity. Caribbean Utilities reported lower earnings due largely to a charge associated with the disposal of steam-turbine assets.

Utility capital expenditures, before customer contributions, were approximately $790 million, including approximately $120 million related to the Terasen Gas companies from the date of acquisition, in 2007.

Utility capital expenditures, before customer contributions, were approximately $790 million, including approximately $120 million related to the Terasen Gas companies from the date of acquisition, in 2007. Over the past five years, our utilities have invested approximately $2.1 billion, on a consolidated basis, in capital projects. Much of this investment occurred at our electric utilities in the high-growth region of western Canada, where growth in customers and energy demand continues at a strong pace.

A number of significant regulatory decisions received in 2007 and early 2008 should provide regulatory stability for 2008, enabling our utilities to focus on operations and meeting the energy needs of customers.

Terasen Gas Inc., FortisBC, Newfoundland Power and Maritime Electric received regulatory approval for their respective 2008 customer rates. In February 2008, FortisAlberta received regulatory approval for the Company's 2008 and 2009 electricity rates. The allowed rates of return on common equity for 2008 for the Corporation's four largest utilities, Terasen Gas Inc., FortisAlberta, FortisBC and Newfoundland Power, increased to 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively.

Terasen Gas (Vancouver Island) Inc. received conditional regulatory approval to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island, which will better enable the Company to meet customers'

current and future gas demand. The $200 million facility is anticipated to be in service by late 2011.

In December 2007, Caribbean Utilities reached an agreement in principle with the Government of the Cayman Islands on the terms of the Company's new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year transmission and distribution licence. The new licences are expected to be issued during the first half of 2008.

The Government of Belize enacted amendments simplifying the tariff-setting methodology at Belize Electricity. The amendments, enacted in December 2007, settled outstanding matters related to the June 2007 regulatory decision on customer rates.

Fortis Properties achieved another milestone in August 2007 when it expanded to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan.

The Fortis Group of Companies serves almost 2,000,000 gas and electricity customers in five Canadian provinces and three Caribbean countries.

Non-regulated Fortis Generation contributed earnings of $24 million compared to $27 million in 2006. Results were impacted by decreased hydroelectric production due to lower rainfall.

Belize Electric Company Limited ("BECOL") began construction of the US$53 million 18-MW Vaca hydroelectric project, the final phase of a three-stage development on the Macal River in Belize, in May. Vaca is expected to increase average annual production from the Macal River by approximately 80 gigawatt hours ("GWh") to 240 GWh. Assuming normal hydrology, the facility is expected to be immediately accretive to earnings per common share when it comes online late in 2009.

For the 10th consecutive year, Fortis Properties delivered record earnings which were $24 million in 2007. Results were driven by expanded hospitality operations in western Canada and a $4 million favourable corporate tax adjustment. The Company achieved another milestone in August 2007 when it expanded its presence to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan. This acquisition was immediately accretive to earnings per common share.

The consolidated capital program for the Fortis utilities in 2008 is forecasted to be approximately $900 million. Over the next five years, cumulative capital expenditures are expected to surpass $4 billion.

With the Terasen acquisition, the total assets of Fortis now exceed $10 billion, almost double that of a year ago and 10 times larger than a decade ago.

Fortis and its subsidiaries raised approximately $2.1 billion in the capital markets in 2007. Coincident with the closing of the Terasen acquisition, the Corporation issued approximately $1.15 billion in Common Shares, the net proceeds of which were used to complete the purchase. The remaining purchase price was funded by assumed debt of $2.4 billion and drawings on the Corporation's existing credit facility. In January 2007, Fortis completed a $150 million Common Share issue, the net proceeds of which were used mainly to repay indebtedness incurred for acquisitions in 2006 and support the capital programs of our electric utilities in western Canada. Following the S&P credit rating upgrade, Fortis completed its first offering of 30-year debt in September 2007 when it issued, by way of private placement, US$200 million 6.6% senior unsecured notes to US-based institutional investors. Fortis subsidiaries completed almost $600 million of long-term debt issues during 2007.

With the Terasen acquisition, the total assets of Fortis now exceed $10 billion, almost double that of a year ago and 10 times larger than a decade ago.

Robust capital investment should continue to drive strong organic growth in earnings and dividends.

The consolidated capital program for our utilities in 2008 is forecasted to be approximately $900 million. Over the next five years, cumulative capital expenditures are expected to surpass $4 billion. Most of this capital investment will occur at our operations in western Canada. By 2012, the combined rate base of FortisAlberta and FortisBC is expected to exceed $3 billion, 76 per cent higher than today's level of $1.7 billion. The combined rate base of all Fortis utilities is expected to grow to approximately $8.6 billion in 2012 compared to the current level of approximately $6.3 billion.

Robust capital investment should continue to drive strong organic growth in earnings and dividends.

While the integration of Terasen within the Fortis Group remains a priority for 2008, Fortis will pursue gas and electric utility acquisitions in Canada, the United States and the Caribbean.

There were a number of leadership changes throughout the Fortis Group during the year. Karl Smith was appointed President and Chief Executive Officer, FortisAlberta following the retirement of Philip Hughes. Earl Ludlow succeeded

Report to Shareholders

Karl as President and Chief Executive Officer, Newfoundland Power. Nora Duke, formerly Vice President, Hospitality Services, Fortis Properties, succeeded Earl as President and Chief Executive Officer, Fortis Properties. Eddinton Powell, formerly Vice President Finance and Chief Financial Officer, Caribbean Utilities, was appointed President and Chief Executive Officer, Fortis Turks and Caicos. With the acquisition of Terasen, its President and Chief Executive Officer, Randall Jespersen, became part of the senior Fortis team.

The success of your Company attests to the calibre and commitment of our employees. Thank you for a job well done.

Messrs. Harry McWatters and Frank Crothers joined our Board of Directors in May 2007, bringing geographic representation for British Columbia and the Caribbean, respectively, and providing additional insight and strengths.

On behalf of the Board of Directors,

Bruce Chafe
Chair of the Board
Fortis Inc.

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

Stan Marshall, President and CEO, Fortis Inc., addresses the Toronto Board of Trade.

The success of Fortis attests to the calibre and commitment of our almost 6,000 employees.

As I will be retiring from your Board of Directors at the Annual Meeting on May 6, 2008, I would like to take this opportunity to extend my thanks and best wishes to the organization. To our employee group, now almost 6,000 strong, your hard work and customer care will continue to underpin the success of our Company.

Bruce Chafe
Chair of the Board
Fortis Inc.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

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

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

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

Terasen

REGULATED GAS OPERATIONS

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving more than 918,000 customers in 125 communities or 96 per cent of gas users in the province.

The Company's regulated natural gas and piped-propane distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the "Terasen Gas companies". Terasen's operations also include Terasen Energy Services, an emerging company focused on integrating alternative energy into district energy systems.

TGI, the main business of Terasen, provides natural gas distribution services to approximately 825,000 customers in over 100 communities. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. It serves approximately 91,200 customers.

TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

In November, TGVI received conditional regulatory approval to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility at Mount Hayes on Vancouver Island.

The Terasen Gas companies own and operate more than 45,000 kilometres of natural gas distribution and transmission pipelines. In 2007, gas volumes were over 220,000 terajoules ("TJ") with a peak day demand of 1,360 TJ. Terasen delivers approximately 20 per cent of the end-use energy consumed in British Columbia.

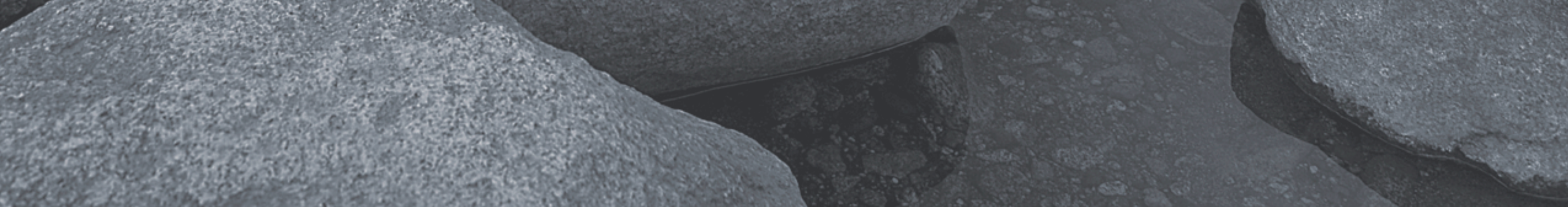
The Customer Choice Program, a new program introduced in British Columbia in May 2007, provides residential customers in most service areas in mainland British Columbia with the option of buying natural gas from an independent gas marketer at a multi-year fixed rate or from TGI at a variable rate. The Program, which gives flexibility to customers, does not impact TGI's earnings as natural gas costs are a direct flow through to customers.

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

The Terasen Gas companies achieved a Customer Satisfaction Rating of 79 per cent in 2007, its highest rating ever. Terasen's team of 1,200 employees undertook a number of initiatives that helped bolster performance, including productivity enhancements, process changes and new sales and marketing activities. Notable activities included increased advertising and communications necessary to support the introduction of the Customer Choice Program and a comprehensive website redesign.

In cooperation with FortisBC and BC Hydro, and with funding from the provincial and federal governments, TGI encouraged customers to conserve energy and save money by offering them financial incentives to upgrade to high-efficiency natural gas heating systems. It is estimated that the approximately 5,000 customers who participated in the Energy Star Furnace-Upgrade Program in 2007 collectively conserved 63,000 gigajoules of energy and reduced their energy costs by $733,000 over the year.

In 2007, the Terasen Gas companies completed approximately $185 million, before customer contributions, in capital programs to ensure the safe, reliable delivery of energy to customers. Major initiatives included an upgrade, reflecting safety advances in piping,



to 95 kilometres of natural gas distribution pipelines and 7,100 household services in five Vancouver neighbourhoods. Construction also began on a 50-kilometre ("km") natural gas pipeline from Squamish to serve Whistler. Once completed, the propane system in Whistler will be replaced by natural gas. In November, conditional regulatory approval was received to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility at Mount Hayes on Vancouver Island. The new storage facility, estimated to cost between $175 million and $200 million, will allow for more efficient use of existing pipeline systems. It will result in improved reliability and security of supply during planned and unplanned system interruptions or in times of high demand. It is expected to come into service by late 2011.

TGI received regulatory approval for thermal metering, a new water-heating measurement method that promotes energy conservation for multi-family complexes. It also provides long-term growth opportunities for the utility through increased market share in British Columbia's growing housing sector.

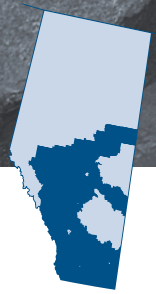
The Terasen Gas companies continued to focus on environmental and safety initiatives, including progress on emissions-reduction requirements. The Transmission Group achieved a milestone, celebrating 33 years without a lost-time injury. Early in the year, the regional flood preparedness plan was implemented to deal with potential flooding from a historically high spring snow-pack melt. Together with the provincial and local governments, the utility helped ensure public safety concerning its natural gas system.

A new five-year collective agreement was negotiated with the Canadian Office and Professional Employees Union, Local 378. The agreement complements the five-year collective agreement negotiated with the International Brotherhood of Electrical Workers, Local 213 in 2006.

Terasen is well positioned as a leading and innovative contributor to British Columbia's energy future.

The Terasen Gas companies own and operate more than 45,000 kilometres of natural gas distribution and transmission pipelines.

FortisAlberta



REGULATED ELECTRIC OPERATIONS

FortisAlberta is an electric utility that distributes electricity, generated by other market participants, to end-use customers in southern and central Alberta. Its electricity system includes approximately 106,000 kilometres of distribution lines and comprises more than 60 per cent of Alberta's total electricity distribution network. The Company serves more than 448,000 customers in 175 growing communities and met a peak demand of 3,182 MW in 2007.

FortisAlberta serves more than 448,000 customers and met a peak demand of 3,182 MW in 2007.

FortisAlberta operates in a dynamic, high-growth environment with significant energy demand. Delivering quality customer service is fundamental to the success of the business. The Company received a Customer Satisfaction Rating of 76 per cent in 2007, consistent with its average annual rating over the past three years.

Approximately $285 million, before customer contributions, was invested in capital projects in 2007, driven largely by growth in customer demand. Capital projects included the construction of an additional $1.5 million distribution line from the new Blackmud substation to support customer demand in the Leduc-Nisku area, which experienced a 10 per cent increase in load growth in 2007. A $2.3 million upgrade of distribution facilities in the Fort Saskatchewan area was undertaken to support the growth of a heavy-oil upgrade megaproject. Approximately $75 million was invested in projects to upgrade conductors and replace aging poles, switches and regulator equipment. New distribution lines were built in the Canmore and Olds areas to provide alternative lines and improve reliability given the increased load growth experienced in these areas in recent years. Work continued on the installation of automated distribution equipment in Airdrie, Banff, Leduc and St. Albert, which will reduce the amount of travel and patrol time required to locate line faults, enabling faster restoration of electricity service.

FortisAlberta worked closely with the transmission service provider and the Alberta Electric System Operator to add substation capacity and improve reliability in Olds, Innisfail, Suffield, Red Deer and Acheson. The Company opened its doors to three new operations facilities in St. Albert, Brooks and Sylvan Lake in 2007. Work continued on the construction of FortisAlberta's new $29 million operations and customer service facility in Airdrie, which is expected to open in 2008.

Officers of FortisAlberta (l-r): Daniel Pigeon, VP, Finance and CFO; Karl Smith, President and CEO; Gary Smith, VP, Operations and Engineering; Cynthia Johnston, VP, Customer Service; Alan Skiffington, VP, Corporate Services and CIO

A pilot program to install Automated Meter Infrastructure ("AMI") technology at more than 26,000 customer sites was successfully implemented in 2007. The technology improves billing accuracy, reduces billing inquiries and enhances customer service. AMI technology will be installed at the Company's remaining customer sites by 2010.

In Alberta's highly competitive labour market, FortisAlberta continues to focus on attracting, developing and retaining a skilled workforce. More than 330 positions were filled by existing staff and new employees this year.

Safe work practices resulted in performance that generally exceeds the Canadian average for utilities of comparable size within the Company's industry group. FortisAlberta led a cooperative safety program in partnership with other Alberta utilities and the Government of Alberta to reinforce the message about the hazards of high-voltage lines. Thirty field offices were recognized for achieving anniversary milestones without lost-time incidents. Nine offices attained seven or more years without a lost-time incident.

FortisBC

REGULATED ELECTRIC OPERATIONS

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers directly and indirectly. Its utility assets include 6,900 kilometres of transmission and distribution lines and four regulated hydroelectric generating plants with a combined capacity of 223 MW on the Kootenay River. The annual gross energy entitlement from the plants is approximately 1,591 GWh. The Company also manages 784 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements, with the balance met through power purchase agreements. The utility met a peak demand of 683 MW in 2007.

FortisBC achieved an average overall Customer Satisfaction Rating of 86 per cent in 2007, a marked improvement from its Customer Satisfaction Rating of 71 per cent three years earlier. Contact Centre personnel attained an average response time of 33.2 seconds and reduced the number of inbound calls almost 10 per cent from the previous year. The Company processed 466 residential extension quotes and 2,227 new service installations were completed in 2007. Based on consultation with customers, an enhanced bill format was designed and introduced.

Focused on creating opportunities for information-sharing and long-term cooperative relationships, FortisBC introduced a public open-house format and new strategies for proactive and timely communication on capital projects. Consultations were held with the public, stakeholders and First Nations on five major infrastructure projects.

In 2007, FortisBC invested a record $147 million, before customer contributions, in capital projects to meet growing energy demand and replace aging infrastructure.

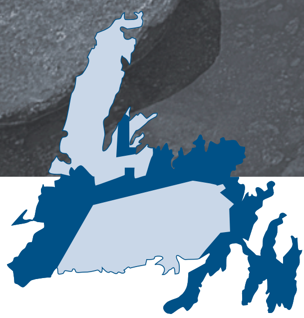
In 2007, FortisBC invested a record $147 million, before customer contributions, in capital projects to meet growing energy demand and replace aging infrastructure. A record number of transmission upgrades were completed this year. The new $20 million Nk'Mip distribution substation and associated 18-km transmission line were constructed to create an additional source of supply into the growing Osoyoos area. The new 23-km transmission line to Big White, the first phase of the $20 million Big White Project, was completed and construction began on the $27 million Kettle Valley Substation Project in the Rock Creek area. Approximately $20 million was invested in the utility's ongoing hydroelectric generation Upgrade and Life-Extension Program in 2007. The Program rebuilds the generating units and auxiliary systems, extending the life of the assets for an estimated additional 40 years.

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

FortisBC continues to lead a cooperative safety awareness campaign in partnership with other British Columbia utilities and safety organizations. The Generation Department achieved over 365 days without a lost-time incident.

FortisBC is committed to environmental stewardship through partnerships with the South Okanagan-Similkameen Invasive Plant Society, the Boundary Weed Management Committee and the Central Kootenay Invasive Plant Committee. The utility also works with multi-agency groups committed to protecting the aquatic environment.

In November 2007, the Government of British Columbia announced the appointment of John Walker, President and Chief Executive Officer, FortisBC, to a new Climate Action Team. The Team's mandate is to make recommendations to the Province on actions to meet its commitment to become carbon neutral by 2010.



Newfoundland Power

REGULATED ELECTRIC OPERATIONS

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 232,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 29 small generating stations with an installed generating capacity of approximately 139 MW, of which 96 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,142 MW in 2007. About 90 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

More than 59 per cent of the $72 million invested, before customer contributions, in capital projects in 2007 was directed to plant and equipment replacement to enhance reliability for customers. The remaining capital investment was driven by commercial and residential construction activity, growth in cottage areas and increased replacement of plant to accommodate fibre-optic cable installations by telecommunication companies in the province.

A $17 million refurbishment of the Rattling Brook hydroelectric generating facility, the largest capital project in dollar terms ever undertaken by the Company, was completed in 2007. The refurbishment will increase the plant's generating capacity to 14.1 MW and should net a 9 per cent increase in power production. The plant now uses approximately 129,000 fewer barrels of oil annually, which will help minimize the impact of fuel costs on electricity rates and benefit the environment.

Strategic capital investment and employee commitment to customer service enabled electricity to be delivered to customers 99.93 per cent of the time in 2007, despite the impact of a severe snowstorm in December which caused major system damage and impacted upwards of 20,000 customers in the Clarenville and Bonavista areas.

A $17 million refurbishment of the Rattling Brook hydroelectric generating facility, the largest capital project in dollar terms ever undertaken by Newfoundland Power, was completed in 2007.

While challenged with increasing energy prices, Newfoundland Power achieved a Customer Satisfaction Rating of 88 per cent in 2007 compared to 89 per cent last year. An independent survey conducted during the year ranked the Company the highest among Canadian utilities of similar size in satisfying residential customers.

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

Providing energy-efficiency programs and services continues to be a focus for the Company. The number of customers requesting energy-efficiency information increased 55 per cent and visits to the *Saving Energy* section of its website increased 76 per cent compared to 2006.

A long-term workforce strategy is in place to address future hiring needs. The utility participates in a trade apprenticeship program as well as post-secondary and high-school career fairs. Twenty apprentice linepersons were in training in 2007, the highest level for the utility since the early 1970s.

In 2007, Newfoundland Power achieved its best safety performance on record. The internationally recognized OHSAS 18001 Health and Safety Management System was implemented to further improve safety performance.

The Company was bestowed the Environmental Performance Award by the Newfoundland and Labrador Environmental Industry Association and received a Business Award of Excellence in the category "Contributions to the Community and Community Service" by the St. John's Board of Trade.

Maritime Electric

REGULATED ELECTRIC OPERATIONS

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI"), serves approximately 72,000 customers, or 90 per cent of electricity consumers in the province, and met a peak demand of 218 MW in 2007. The utility owns and operates a fully integrated system comprised of more than 5,200 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity across the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait.

In 2007, the Company purchased more than 87 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these stations. The Point Lepreau Station will undergo an 18-month refurbishment beginning on April 1, 2008 that will extend its life by 25 years, providing additional stability with respect to long-term energy supply. The remainder of off-Island energy purchases is made at market prices under an agreement with NB Power. Maritime Electric obtains the balance of its energy requirements either from its own generating plants or from on-Island wind-powered generation facilities.

The Company invested approximately $27 million, before customer contributions, in 2007 to improve system reliability and customer service. Construction was completed on a $2.5 million 69-kilovolt ("kV") transmission line that delivers wind-powered energy from a commercial operation in western PEI to the North American grid. Maritime Electric supports the development of PEI's wind resource and its integration into the overall energy supply strategy in a timely and consistent manner. The Company issued a Request for Expressions of Interest for wind-powered energy development projects to ensure the utility's system-development planning process enables wind-powered energy to comprise part of PEI's long-term energy supply.

In September 2007, Maritime Electric secured 30 MW of transmission capacity on the International Power Line, a second transmission line between New Brunswick and Maine. This line will increase both northbound and southbound flows with New England and should increase energy supply options.

Maritime Electric invested approximately $27 million, before customer contributions, in 2007 to improve system reliability and customer service.

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

Maritime Electric received a Customer Satisfaction Rating of 73.3 per cent in 2007 compared to 79.5 per cent in 2006. A considerable number of customer outages in 2007 were due to extreme weather conditions including severe lightning, Tropical Storm Noel and a major ice storm.

An external audit of the Company's Safety Management System referenced numerous achievements since completion of the previous audit, particularly the many steps taken by Maritime Electric in demonstrating its commitment to safety. The development of a Safe Work Management System to manage safety and to document policies, procedures and programs was instrumental in the improvement of the overall rating. The completion of a new vehicle and crew assignment system helps meet the requirements of working-alone legislation.

FortisOntario

REGULATED ELECTRIC OPERATIONS

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power and Cornwall Electric. Its utilities serve approximately 52,000 customers, mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario. The Company owns regulated transmission assets in the Niagara and Cornwall regions, including an interconnection between New York State and Fort Erie, Ontario. It has more than 1,360 kilometres of transmission and distribution lines and met a combined peak demand of 234 MW in 2007. FortisOntario owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies serving more than 27,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec.

In 2007, a new $1.4 million substation was commissioned in Gananoque, providing improved reliability and security of service to the community.

FortisOntario invested $11 million, before customer contributions, in capital expenditures in 2007 to connect new customers and upgrade its transmission and distribution assets to further improve system reliability and safety. During the year, work continued on the conversion of the 4.8-kV Fort Erie system to an 8.3-kV system. Progress was made on the Port Colborne SCADA expansion program, designed to enhance remote monitoring and control of substations. A new $1.4 million substation was commissioned in Gananoque, providing improved reliability and security of service to the community. A Service Centre for Gananoque field operations was also refurbished, improving efficiencies for field personnel. Capital programs in Cornwall focused on new customer connections, as well as planned line improvements to replace deteriorated plant and improve system security. Major capital works included a 115-kV transmission line relocation and the replacement of aging underground distribution switching units.

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

FortisOntario achieved a Customer Satisfaction Rating of 83 per cent in 2007, similar to the rating achieved in 2006. Customers continue to rate reliability/safe delivery of electricity and quality of service as high priorities at 90 per cent and 85 per cent, respectively. The Company continues to exceed performance standards set by the Ontario Energy Board with respect to response times, service connections and call-answer statistics.

FortisOntario, in conjunction with the Ontario Power Authority, launched four electricity-conservation and demand-management programs in 2007. The Summer Savings Program encouraged customers to reduce electricity consumption by 10 per cent in July and August with a 10 per cent credit for customers achieving the reduction. More than 30 per cent of eligible customers met the reduction target.

FortisOntario met or exceeded all of its health, safety and environmental key performance indicators for 2007, including zero lost-time injuries for all work locations. FortisOntario, Cornwall Electric and Canadian Niagara Power each received the Silver Safety Award from the Electrical & Utilities Safety Association of Ontario in recognition of their successful plans to implement a sustainable health and safety management system.

Belize Electricity

REGULATED ELECTRIC OPERATIONS

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 73,000 customers, the utility met a peak demand of 70 MW in 2007 from multiple sources of energy, including power purchases from BECOL, Comisión Federal de Electricidad (the Mexican state-owned power company), Hydro Maya Limited and from its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 36 MW and owns approximately 2,740 kilometres of transmission and distribution lines. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.

Belize Electricity earned a Customer Satisfaction Rating of 84 per cent in 2007.

Through its pursuit of competitively priced energy sources, the Company was able to maintain stable electricity rates in the face of record-breaking oil prices. Hydroelectricity supplied approximately 40 per cent of the country's peak energy demand, which grew by approximately 5 per cent in 2007.

Capital investments to expand and improve the electricity system surpassed US$23.5 million, before customer contributions, in 2007. Almost 95 kilometres of distribution lines were constructed countrywide, including line extensions to electrify several rural communities under the Power III Rural Electrification Project, a joint initiative between Belize Electricity and the Government of Belize. Since the Project's establishment in 1999, approximately US$15 million has been invested in capital initiatives for this Project and first-time service has been extended to more than 11,000 customers. Capital projects were also undertaken to connect tourism developments in the popular tourist destinations of San Pedro Town and Placencia Village, to connect a large-scale shrimp farm in southern Belize and to replace aging distribution systems in the Belize District.

During 2007, more than 7,000 electronic meters were installed to replace aging equipment. Improvements were also made to the bill-editing and meter-sealing programs and meter inspections continued countrywide.

Belize Electricity earned a Customer Satisfaction Rating of 84 per cent in 2007. A significant customer service initiative during the year was the installation of an Automated Call Distributor and Interactive Voice Response System. The System provides call-in customers with automated information such as service restoration times, bill payment due dates and account balances. An extensive renovation of the customer service office in Punta Gorda Town, the southernmost municipality in the country, was also completed during the year.

Officers of Belize Electricity (l-r): Joseph Sukhnandan, VP, Engineering and Energy Supply; Juliet Estell, Manager, Executive Services and Company Secretary; Lynn Young, President and CEO; Rene Blanco, VP, Finance and CFO; Felix Murrin, VP, Customer Care and Operations (Effective October 29, 2007, Mr. Curtis Eck was appointed VP, Customer Care and Operations following the retirement of Mr. Murrin.)

Safety training remains an integral component of daily operations. In August 2007, the Company implemented a new service-installation guide consistent with the National Electric Code used in North America. Training by FortisAlberta now enables Belize Electricity to conduct independent in-house training on work methods, such as hot-stick and rubber-glove live-line maintenance techniques, which helps improve system reliability.

The Company continues to make meaningful progress towards becoming ISO 14001 compliant by 2009. The Environmental Management System is now implemented in all high-risk areas and efforts are underway to roll out the system to low-risk areas.

Caribbean Utilities

REGULATED ELECTRIC OPERATIONS

Caribbean Utilities generates, transmits and distributes electricity to more than 23,000 customers on Grand Cayman, Cayman Islands. The Company is one of the most reliable and efficient utilities in the region. The utility owns and operates approximately 550 kilometres of transmission and distribution lines and 22 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 137 MW and met a record peak demand of approximately 93 MW in August 2007.

Caribbean Utilities owns and operates approximately 550 kilometres of transmission and distribution lines and 22 kilometres of high-voltage submarine cable.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis increased its investment in Caribbean Utilities to approximately 54 per cent in November 2006, becoming controlling shareholder.

Caribbean Utilities earned a Customer Satisfaction Rating of 84 per cent in 2007. Customer service initiatives undertaken throughout the year included marketing of external payment options, such as direct debit; implementation of Telelink, an automated voice-activated customer-service system; the continued installation of new automated meters; and promotion of the Energy Smart Program, designed to help customers conserve energy. The Company offers free residential and commercial energy audits to all customers as part of its Energy Smart activities.

System reliability was 99.95 per cent year-to-date October 31, 2007. Capital expenditures for the fiscal year ended April 30, 2007 totalled US$36 million, before customer contributions. Major capital projects included the US$22 million 16-MW diesel-fired generating unit and auxiliary equipment commissioned in June 2007, and transmission and distribution projects, which will further enhance system reliability. Information technology projects included the development of business continuity plans for several departments and an enterprise-wide Crisis Management and Business Continuity Plan.

Caribbean Utilities has a comprehensive Environmental Management System and was recertified as compliant with ISO 14001:2004 for its power generation, transmission and distribution systems. The Company is the only organization in the Cayman Islands with ISO 14001 certification. Environmental Management System initiatives included ongoing emergency preparedness planning, continuous employee education programs, and stringent environmental and structural design standards.

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

With 193 employees, more than 90 per cent of whom are Caymanian, Caribbean Utilities recorded more than 11,000 employee training hours for its fiscal year 2007. Training initiatives included information technology instruction to a diverse group of employees, as well as an internationally recognized accredited apprenticeship program for employees of the Production and Transmission Division.

Employee and public safety practices remain a priority. Initiatives this year included contractor safety programs, revisions to energy-control procedures, Occupational Safety and Health Administration-certified courses and monthly health and safety meetings.

The Company continues its commitment to the "Investors in People" certification, which was achieved in early 2006. This internationally recognized standard aligns the utility's human resource strategies with its business objectives. Employee-development initiatives will continue throughout 2008 as the utility strives to maintain its employer-of-choice position in the country.

Fortis Turks and Caicos

REGULATED ELECTRIC OPERATIONS

Fortis Turks and Caicos serves more than 8,700 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands. It owns and operates a fully integrated system providing for the generation and distribution of energy in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. It also owns and operates an independent generating station and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. The Company has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 28 MW in 2007. Fortis Turks and Caicos owns and operates 325 kilometres of transmission and distribution lines.

A major focus has been the integration of Fortis Turks and Caicos within the Fortis Group of Companies since its acquisition in August 2006. In July 2007, Mr. Eddinton Powell, formerly Vice President Finance and Chief Financial Officer, Caribbean Utilities, took the helm as President and Chief Executive Officer, Fortis Turks and Caicos. Under his leadership, management remains focused on meeting the growing needs of customers.

The utility's customer base increased 13 per cent in 2007, driven largely by strong economic growth in the country. Current economic conditions on the Turks and Caicos Islands suggest the Company can expect to achieve growth in energy demand in the range of 18 per cent to 25 per cent per annum over the next several years. The robust growth in energy demand is being driven by tourism and the high level of condominium and hotel development. One of the utility's large hotel customers, for example, is investing US$68 million to expand its facility to more than 600 rooms.

Fortis Turks and Caicos has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 28 MW in 2007.

Fortis Turks and Caicos invested US$24 million, before customer contributions, in capital projects in 2007 to meet current and projected growth in energy demand resulting from a rapidly growing customer base. Two diesel-fired generating units, with a combined generating capacity of 7 MW, were commissioned in 2007. Four additional units, with a combined generating capacity of 13 MW, were purchased during the year and will be installed in 2008 and 2009. The rapid increase in load has necessitated the expansion of the Richmond Hill and Grace Bay substations. The Grace Bay substation, which was brought into service only a year ago, is reaching its installed capacity and considerable work has been carried out to double its capacity by the end of 2008.

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

Throughout 2007, Fortis Turks and Caicos developed and implemented a number of programs designed to enhance customer service. A new Customer Care Centre was opened in December. The Company also installed a new automated meter-reading system that will greatly improve the efficiency of the meter-reading process. As part of its efforts to enhance customer relations, management is focused on developing strong working relationships with its on-Island stakeholders.

Safety and employee development remain key operational priorities for Fortis Turks and Caicos. Throughout 2007, safety training was provided to employees in high-risk jobs and job-specific training was provided to meter technicians, control room operators, line apprentices, engineering service staff, customer service agents and information systems staff.

Fortis Generation

NON-REGULATED OPERATIONS

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these non-regulated assets is 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production was 167 GWh in 2007, a slight decrease from last year due to lower rainfall levels. Production was still above expected levels based on historical average rainfall. BECOL sells its entire output to Belize Electricity under a 50-year Power Purchase Agreement ("PPA").

In May 2007, construction began on the US$53 million 18-MW Vaca hydroelectric generating facility situated approximately five kilometres downstream of Mollejon. Vaca is the final phase of the three-stage hydroelectric development plan for the Macal River. The run-of-river facility will increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Belize Electricity has signed a 50-year PPA with BECOL for the purchase of energy generated by the Vaca facility, commencing late in 2009.

In May 2007, construction began on the US$53 million 18-MW Vaca hydroelectric generating facility situated approximately five kilometres downstream of Mollejon on the Macal River in Belize.

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

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi-Consolidated's two hydroelectric generating plants in central Newfoundland. Abitibi-Consolidated continues to use the historical annual generation while the additional energy produced as a result of the project is sold to Newfoundland Hydro under a 30-year PPA. The Exploits Partnership achieved production of 137 GWh in 2007.

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

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

Fortis Properties

NON-REGULATED OPERATIONS

Fortis Properties owns and operates 19 hotels, offering more than 3,500 rooms, in eight Canadian provinces, and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

In August 2007, Fortis Properties expanded to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan. The complex is comprised of 274 hotel rooms, the Saskatchewan Trade and Convention Centre, 52,000 square feet of Class A commercial office space and a parking garage. The hotel strengthens the Company's hotel portfolio while increasing its presence in western Canada.

The Hospitality Division showed continued improvement in customer satisfaction ratings in 2007. The Delta St. John's Hotel and Conference Centre was recognized by Delta Hotels with the *Best in Class, Guest Satisfaction* and *Most Improved Guest Satisfaction* awards, recognizing employee excellence in customer service. Additionally, the Delta St. John's and Delta Brunswick placed in the top three for the *Hotel of the Year, Franchise* award. Revenue per available room ("REVPAR") increased for the 12th consecutive year, reaching $79.31. The increase in REVPAR was primarily attributable to the addition of the four hotels in western Canada, acquired in November 2006, and the Delta Regina.

The Real Estate Division is anchored by high-quality tenants under long-term leases with a year-end occupancy rate of 96.8 per cent, outpacing the national rate of 93.8 per cent.

The Building Owners and Managers Association ("BOMA") Atlantic recognized Blue Cross Centre in Moncton, New Brunswick with the BOMA Environmental Stewardship Award. The award acknowledged the property's efforts in limiting its environmental impact through its energy-efficient building design, energy- and water-consumption tracking, and recycling initiatives.

Fortis Properties owns and operates 19 hotels, offering more than 3,500 rooms, in eight Canadian provinces.

The $2 million recladding of the Delta Sydney in Nova Scotia was completed in November 2007. The project remedied building infrastructure issues and revitalized the property's exterior, increasing its attractiveness in the market. Work began on a $1.4 million electrical refit at the Delta Brunswick/Brunswick Square complex to improve building infrastructure and ensure the continued comfort of guests and tenants.

Officers of Fortis Properties (l-r): Neal Jackman, VP, Finance and CFO; Nora Duke, President and CEO; Wayne Myers, VP, Real Estate

A Company-wide Health and Safety Plan was launched in 2007 with emphasis placed on key initiatives such as safety communication and leadership, safety training and orientation, incident reporting, contractor management, and early and safe return to work. Safety audits were conducted at 19 properties and will continue throughout 2008 for the remainder of the properties.

Employee development initiatives continued with the provision of special assignments and secondments to enhance employee performance. The Company's Mentoring Program continued and a renewed emphasis was placed on leadership development. Training was completed in the areas of respectful workplace, collective agreement administration, and health and safety.

Our Community

Our team spirit extends beyond our office buildings and operational facilities. It kicks into high gear on soccer fields, marches along in school parades, helps fill food bank shelves and champions scores of community events where volunteers make a difference in the quality of daily living for others.

In 2007, the Fortis Group of Companies contributed almost $3 million in financial and in-kind donations to a wide spectrum of worthy community causes. Hundreds of our employees were involved.

Here's a few of the community initiatives we were proud to support:

Terasen donated 40 desktop computers to *Seabird Island First Nation*. The computers will be part of a network that will provide high-speed broadband wireless access to the community of Seabird Island.

FortisAlberta and its employees donated $148,000 to the eight *United Way* chapters in its service territories across Alberta, exceeding the campaign goal of $125,000 and surpassing the Company's 2006 donation by more than $40,000.

FortisBC employees and volunteers participated in the 5th annual *Moving Mountains Relay*, a 370-km run from Trail to Kelowna. More than $21,000 was raised to help purchase an osteotomy hip system for the Orthopedic Unit at the BC Children's Hospital.

Newfoundland Power pledged $350,000 to *PRIORITY: The Campaign for Cancer Care* for the purchase of a new four-dimensional CT simulator for the Dr. H. Bliss Murphy Cancer Centre. The equipment will enable the cancer care team to enhance the accuracy of radiation treatment for cancer patients.

Maritime Electric sponsors an annual *$5,000 Environmental Studies Grant Program*. The funds are used to help educate high school students about issues pertaining to the natural environment and how it can be managed in a sustainable manner.

FortisOntario donated a collection of historical documents, photos and artifacts depicting the beginning and evolution of electricity in Canada to the *Cornwall Museum*. Valued at more than $230,000, the donation was the largest in the museum's history.

Belize Electricity has pledged US$10,000 over three years to the *Belize Emergency Response Team*. The non-profit organization is the only fully trained and equipped ambulance service in Belize.

Employees of Caribbean Utilities contributed over 300 hours to community events. The Company was the principal sponsor of the *CUC Primary Football League* with more than 15 primary schools across Grand Cayman participating.

Fortis Turks and Caicos completed its first annual *Home Makeover* in December. Home is where the heart is and employees put their hearts into helping complete some major roof repairs, install new light fixtures and upgrade the property of a well-deserving community member.

Fortis Properties partnered with community groups and the Government of Newfoundland and Labrador on the *Makin' It Work* project. The initiative provides unemployed or underemployed persons with on-the-job training for frontline hospitality positions.

Thanks to our employees and all volunteers for stepping forward.

Management Discussion and Analysis

Dated March 14, 2008

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

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in the Fortis Inc. 2007 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. *Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified. Fortis Inc. ("Fortis" or the "Corporation") includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's expectation to generate sufficient cash required to complete planned capital programs from a combination of long-term debt and short-term borrowings, internally generated funds and the issuance of common shares and preference shares; the Corporation's belief that it does not anticipate any difficulties in accessing the required capital on reasonable market terms; the Corporation's consolidated forecasted gross capital expenditures for 2008 and in total over the next five years, as well as expected significant capital projects in 2008 and their expected cost and time to complete; the Corporation's expectation of the impact of foreign exchange on 2008 basic earnings per common share; and the Corporation's belief that its capital program should drive growth in earnings and dividends. 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 events; the Corporation's ability to maintain its gas and electricity systems to ensure their continued performance; the competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the availability of natural gas supply; favourable economic conditions; the level of interest rates; the ability to hedge certain risks; access to capital; maintenance of adequate insurance coverage; the ability to obtain licences and permits; the level of energy prices; retention of existing service areas; 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. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulation; integration of Terasen Inc. and management of expanded operations; operating and maintenance risks; natural gas prices and supply; economic conditions; weather and seasonality; interest rates; changes in tax legislation; derivative instruments and hedging; risks related to Terasen Gas (Vancouver Island) Inc.; capital resources; environment; insurance; licences and permits; energy prices and the cessation of the Niagara Exchange Agreement; loss of service area; First Nations Lands; counterparty risk; labour relations; human resources; and liquidity risk. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the year ended December 31, 2007.*

All forward-looking information in the MD&A is qualified by 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.

A discussion of the financial condition and results of operations for the fourth quarter of 2007 is contained in the Corporation's Interim MD&A for the 3 and 12 months ended December 31, 2007 dated and filed on SEDAR at www.sedar.com on February 7, 2008.

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility company in Canada, serving almost 2,000,000 gas and electricity customers. Its regulated holdings include a natural gas distribution utility in British Columbia and electric distribution utilities in five Canadian provinces and three Caribbean countries. Fortis owns non-regulated generation assets across Canada and in Belize and Upper New York State. It also owns hotels and commercial real estate across Canada. In 2007, the Corporation's electricity distribution systems met a combined peak electricity demand of approximately 5,700 megawatts ("MW") and its gas distribution system met a peak day demand of 1,360 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, the Corporation pursues growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, and deliver gas and electricity safely and reliably to customers at reasonable rates. The Corporation's core business is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The reporting segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates which factor into customer rate-setting mechanisms.

Fortis also holds investments in non-regulated generation assets, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 195 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, to enable leveraging of expertise across the various jurisdictions and to allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility, and enhance shareholder return.

The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility, and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 825,000 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 91,200 residential, commercial and industrial customers.

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

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving over 448,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 223 MW. During 2007, the entitlement capacity and energy output for a number of FortisBC Inc.'s hydroelectric generating units were optimized as a result of past turbine and generator upgrade projects. Entitlement capacity was rebalanced from 235 MW to 223 MW and energy output increased by 11,000 megawatt hours ("MWh") as a result of negotiated adjustments to the Canal Plant Agreement with BC Hydro. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC's assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 232,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 96 MW is hydroelectric generation.

d. *Maritime Electric:* Maritime Electric is the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 72,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW.

e. *FortisOntario:* FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000, serving more than 27,000 customers.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 73,000 customers. The Company has an installed generating capacity of 36 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 23,000 customers. The Company has an installed generating capacity of approximately 137 MW. On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities' October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation's December 31, 2007 consolidated financial statements. During 2006, the statement of earnings of Fortis reflected the Corporation's approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on an equity basis, on a two-month lag.

c. *P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively referred to as Fortis Turks and Caicos):* Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 8,700 customers. The Company has a combined diesel-fired generating capacity of 48 MW. Fortis Turks and Caicos was acquired by Fortis, through a wholly owned subsidiary, on August 28, 2006.

Non-Regulated – Fortis Generation

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

a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.

b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Since the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties has held directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership, a wholly owned partnership of FortisBC Inc.

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 19 hotels with more than 3,500 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. Terasen was acquired by Fortis on May 17, 2007.

Financial Highlights

For the Years Ended December 31st	**2007**	2006	Variance *(%)*
Net earnings applicable to common shares *($ millions)*	**193**	147	31.3
Basic earnings per common share *($)*	**1.40**	1.42	(1.4)
Diluted earnings per common share *($)*	**1.32**	1.37	(3.6)
Weighted average number of common shares outstanding *(millions)*	**137.6**	103.6	32.8
Revenue and equity income *($ millions)*	**2,718**	1,472	84.6
Dividends paid per common share *($)*	**0.82**	0.67	22.4
Return on average common shareholders' equity *(%)*	**9.99**	11.87	(15.8)
Total assets *($ millions)*	**10,273**	5,441	88.8
Cash flow from operating activities *($ millions)*	**373**	263	41.8

Acquisitions: On May 17, 2007, Fortis completed the acquisition of all of the issued and outstanding common shares of Terasen, formerly a wholly owned subsidiary of Kinder Morgan, Inc. for aggregate consideration of $3.7 billion, including the assumption of approximately $2.4 billion of consolidated debt. Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. Terasen is the principal natural gas distributor in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province. The acquisition did not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

A significant portion of the net cash purchase price of Terasen was satisfied with the net proceeds of the public offering of Subscription Receipts completed by Fortis on March 15, 2007. Fortis issued 44,275,000 Subscription Receipts for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition on May 17, 2007, each Subscription Receipt was automatically exchanged, without payment of additional consideration, for one Common Share of Fortis. Each Subscription Receipt holder also received a cash payment of 21 cents per Subscription Receipt, which was an amount equal to the dividend declared per Common Share of Fortis to holders of record as of May 4, 2007. The remaining net cash purchase price was financed, on an interim basis, by drawing $125 million on the Corporation's existing credit facility.

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

On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities for approximately $56 million (US$49 million), and now owns approximately 54 per cent of the Company.

On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia for an aggregate cash purchase price of approximately $52 million. The four hotels acquired were the Holiday Inn Express and Suites, and Best Western, in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia.

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all of the issued and outstanding shares of Fortis Turks and Caicos for cash consideration of approximately $98 million (US$88 million). Fortis Turks and Caicos serves more than 8,700 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Key Trends and Risks: The acquisition of Terasen improves the risk profile of Fortis by providing the Corporation with a more economically diverse portfolio of assets and earnings. The expansion into natural gas added a new business segment, doubled the regulated rate base of Fortis to approximately $6.3 billion and was complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The distribution franchises of the Terasen Gas companies have a well-diversified, mature, principally residential customer base and operate in a service territory that is experiencing strong economic growth and includes substantially all of the service territory of FortisBC. The expansion into natural gas distribution provides Fortis with a platform for future growth in the regulated natural gas business in Canada and the United States.

Following the Terasen acquisition, a large proportion of the businesses of Fortis serve the high-growth economies of western Canada. At December 31, 2007, regulated utility assets comprised 92 per cent of total assets compared to 86 per cent at December 31, 2006. At December 31, 2007, regulated utility assets in Canada comprised 84 per cent of total assets compared to 71 per cent at December 31, 2006.

Over the past few years, declining long-term interest rates in Canada have negatively impacted the allowed rate of return on common shareholders' equity ("ROE") used to set customer rates at each of the Corporation's four largest regulated utilities. However, due to a modest increase in long-term Canada bond rates during 2007, the allowed ROEs at TGI, FortisAlberta, FortisBC and Newfoundland Power were increased, for the purpose of setting customer rates in 2008, in accordance with the automatic adjustment formulas approved by the respective regulators. The chart below highlights the trend in the regulator-allowed ROEs at the above named utilities:

Regulator-Allowed ROE

(%)	2005	2006	2007	2008
TGI	9.03	8.80	8.37	8.62
FortisAlberta	9.50	8.93	8.51	8.75
FortisBC	9.43	9.20	8.77	9.02
Newfoundland Power	9.24	9.24	8.60	8.95

The impact on the Corporation's earnings of lower allowed ROEs was largely offset by increased rate bases and energy sales and the realization of operating cost efficiencies.

Economic growth in the province of Alberta has been robust, translating into strong customer and energy sales growth in FortisAlberta's service territory. This service territory includes environs of Calgary and Edmonton and includes the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC over the past few years. As a result, organic earnings growth derived from investment in utility infrastructure at the Corporation's Canadian regulated electric utilities is expected to be primarily driven by FortisAlberta and FortisBC. The Corporation's other Canadian regulated electric utilities – Newfoundland Power, Maritime Electric and FortisOntario – operate in more mature, stable environments, resulting in slower earnings growth.

With the acquisition of Terasen, regulated assets in the Caribbean region, as a percentage of total regulated assets, have decreased from 18 per cent at December 31, 2006 to 8 per cent at December 31, 2007. The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher compared to that achieved in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential hurricane damage and related business interruption.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. In late 2007 and early 2008, regulator-approved negotiated settlement agreements were reached at FortisBC and Newfoundland Power for 2008 electricity rates and at FortisAlberta for 2008 and 2009 electricity rates. Achieving regulator-approved negotiated settlement agreements has eliminated the cost of full-scale public hearing processes. In December 2007, an agreement in principle ("AIP") was reached between Caribbean Utilities and the Government of the Cayman Islands on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence. The new licences are expected to be issued during the first half of 2008. In December 2007, regulatory amendments were enacted in Belize which settled outstanding matters associated with the regulator's decision concerning Belize Electricity's 2007/2008 electricity rates. In January 2008, Maritime Electric received regulatory approval for 2008 electricity rates. Although the potential receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieve a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of the Corporation's operations. For a complete discussion of regulatory activity and decisions and the Corporation's business risks, see the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Common share dividend payments increased to 82 cents per common share in 2007. A 19 per cent increase in the quarterly common share dividend to 25 cents from 21 cents, effective for the first quarter of 2008, extends the Corporation's record of annual common share dividend increases to 35 consecutive years, the longest record of any public corporation in Canada. Growth in earnings has enabled Fortis to increase its quarterly common share dividend 92 per cent since 2003.

Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $193 million in 2007, a 31.3 per cent increase over earnings of $147 million last year. Basic earnings per common share were $1.40 in 2007 compared to $1.42 last year.

The growth in overall earnings was primarily attributable to the acquisition of Terasen in May 2007, but also reflected the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes.

The seasonality of earnings of the Terasen Gas companies, combined with the impact of a $1.15 billion common share issue to fund a substantial portion of the cash purchase price of Terasen, diluted basic earnings per common share by 7 cents in 2007.

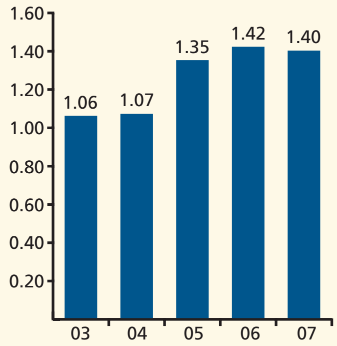
Revenue and Equity Income: Revenue and equity income increased almost 85 per cent to approximately $2.72 billion from approximately $1.47 billion last year. Revenue of $905 million from the Terasen Gas companies, from the date of acquisition, was the main driver of the increase. The remainder of the increase was driven by Caribbean Utilities, Newfoundland Power, Fortis Properties and Fortis Turks and Caicos. Due to the increase in the Corporation's ownership in Caribbean Utilities to an approximate 54 per cent controlling interest in November 2006, Fortis has been consolidating Caribbean Utilities' financial results since the first quarter of 2007. During 2006, the statement of earnings of Fortis reflected the Corporation's approximate 37 per cent interest in Caribbean Utilities, previously accounted for on an equity basis. The increase in revenue at Newfoundland Power was driven by the flow through of higher purchased power costs, and the increase in revenue at Fortis Properties was primarily due to expanded hospitality operations in western Canada. The increase in revenue at Fortis Turks and Caicos was due to the first full year of ownership by Fortis.

Dividends: Dividends paid per common share increased to 82 cents in 2007 from 67 cents last year. On June 1, 2007, Fortis increased its quarterly common share dividend paid to 21 cents from 19 cents. Commencing with the first quarter dividend paid on March 1, 2008, Fortis increased its quarterly common share dividend 19 per cent to 25 cents per common share from 21 cents. The Corporation's dividend payout ratio was 58.6 per cent in 2007 compared to 47.2 per cent last year.

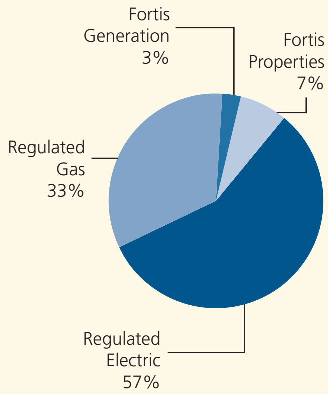
Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 10.0 per cent in 2007 compared to 11.9 per cent last year. The decrease reflected the impact of a lower ROE in 2007 at each of the Corporation's three largest electric utilities and the part-year ownership and seasonality of earnings of the Terasen Gas companies.

Asset Growth: Total assets increased almost 89 per cent to approximately $10.27 billion at year-end 2007 from $5.44 billion at year-end 2006, driven by the acquisition of Terasen. Of the approximate $4.8 billion increase in total assets year over year, approximately $4.5 billion, including goodwill of $907 million, related to Terasen. The remaining increase in assets was primarily due to the Corporation's continued investment in electricity systems, driven by the capital expenditure programs at FortisAlberta and FortisBC, and the acquisition of the Delta Regina, partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets.

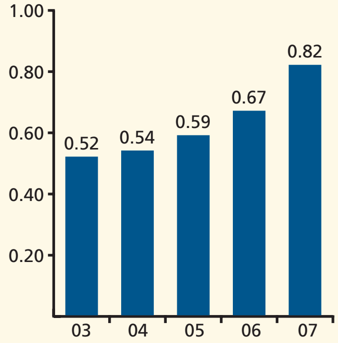
Basic Earnings per Common Share *($)*



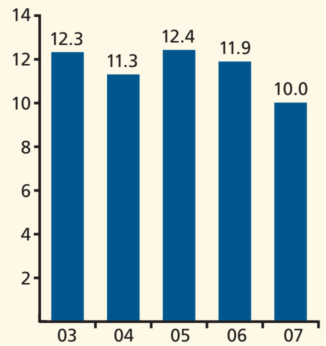
Total Revenue
(year ended December 31, 2007)



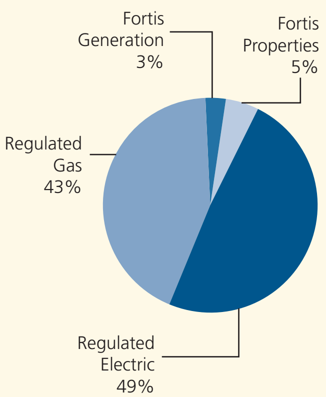
Dividends Paid per Common Share *($)*



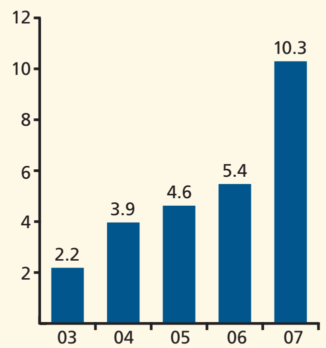
Return on Average Common Shareholders' Equity *(%)*



Total Assets
(as at December 31, 2007)



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



Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $373 million in 2007, 41.8 per cent higher than $263 million last year. The increase in cash flow from operating activities, after working capital adjustments, was driven by FortisAlberta, Caribbean Utilities and FortisBC, partially offset by cash used in operating activities at the Terasen Gas companies.

2007 Capital Expenditures: During 2007, consolidated utility capital expenditures, before customer contributions ("gross utility capital expenditures"), were $790 million, including $120 million related to the Terasen Gas companies from the date of acquisition. Total capital investment at FortisAlberta and FortisBC during 2007 was approximately $432 million, representing approximately 55 per cent of total gross utility capital expenditures. Much of this capital investment was driven by robust customer growth and the need to enhance the reliability of electricity systems.

Financings: During 2007, Fortis and its subsidiaries raised approximately $2.1 billion of capital from a combination of common share and long-term debt issuances. In January 2007, 5.17 million Common Shares were publicly offered for gross proceeds of approximately $150 million. The proceeds were primarily used to repay existing indebtedness incurred under the Corporation's committed credit facilities, principally to fund a portion of acquisitions in 2006; to support capital expenditure programs of the Corporation's regulated electric utilities in western Canada; and for general corporate purposes. In May 2007, the Corporation publicly issued 44.3 million Common Shares for gross proceeds of approximately $1.15 billion, upon conversion of Subscription Receipts that were initially issued in March 2007, to finance a significant portion of the net cash purchase price of Terasen. In September 2007, Fortis privately placed 30-year US$200 million 6.60% unsecured notes, the proceeds of which were used to repay existing indebtedness previously borrowed under the Corporation's committed credit facility associated with the Terasen acquisition, and for general corporate purposes. At the subsidiary level, FortisAlberta issued 40-year $110 million 4.99% unsecured debentures in January 2007; FortisBC issued 40-year $105 million 5.90% unsecured debentures in July 2007; Newfoundland Power issued 30-year $70 million 5.901% first mortgage sinking fund bonds in August 2007; Caribbean Utilities privately placed 15-year US$40 million 5.65% unsecured notes in total in June and November 2007; and TGI issued 30-year $250 million 6.00% unsecured debentures in October 2007. Proceeds from the long-term debt issuances at the electric utilities were primarily used to repay indebtedness previously borrowed under their respective committed credit facilities incurred in support of capital spending. The proceeds from the issuance of $250 million unsecured debentures by TGI were used to refinance $250 million of existing debt that matured in October 2007. Investor confidence in the growth strategy of Fortis resulted in the execution of the above financings at attractive rates and terms.

Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings
Years Ended December 31st

($ millions)	**2007**	2006	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies[(1)]	**50**	–	50
Regulated Electric Utilities – Canadian			
FortisAlberta	**48**	42	6
FortisBC	**31**	27	4
Newfoundland Power	**30**	30	–
Other Canadian[(2)]	**16**	14	2
	125	113	12
Regulated Electric Utilities – Caribbean[(3)]	**31**	23	8
Non-Regulated – Fortis Generation	**24**	27	(3)
Non-Regulated – Fortis Properties[(4)]	**24**	19	5
Corporate and Other[(5)]	**(61)**	(35)	(26)
Net Earnings Applicable to Common Shares	**193**	147	46

(1) Financial results are from May 17, 2007, the date of acquisition.
(2) Includes Maritime Electric and FortisOntario
(3) Includes Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos acquired on August 28, 2006. Results for 2007 reflect the consolidation of Caribbean Utilities' financial statements on a two-month lag basis. Results for 2006 reflect the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities accounted for on an equity basis on a two-month lag.
(4) Includes the results of Delta Regina from August 1, 2007, the date of acquisition
(5) Includes net corporate expenses and, from May 17, 2007, the net expenses of non-regulated Terasen corporate-related activities and Terasen's 30 per cent ownership interest in CWLP

REGULATED UTILITIES

The Corporation's primary business is regulated utilities. The regulated earnings in Canada and the Caribbean represented approximately 81 per cent of the Corporation's earnings from its operating segments in 2007 (2006 – 75 per cent). Total regulated assets represented 92 per cent of the Corporation's total assets as at December 31, 2007 (December 31, 2006 – 86 per cent).

Regulated Gas Utilities – Canadian

Terasen Gas Companies

Financial Highlights

Year Ended December 31st[(1)]	**2007**
Gas Volumes *(TJ)*	**118,309**
($ millions)	
Revenue	**905**
Energy Supply Costs	**559**
Operating Expenses	**150**
Amortization	**58**
Finance Charges	**80**
Gain on Sale of Property	**(8)**
Corporate Taxes	**16**
Earnings	**50**

(1) Data is from May 17, 2007, the date of acquisition.

On May 17, 2007, Fortis acquired all of the issued and outstanding shares of Terasen. Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. Terasen is the principal distributor of natural gas in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province. TGI provides gas distribution services to a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns a combined gas distribution and transmission system serving customers along the Sunshine Coast and in various communities on Vancouver Island, including Victoria and surrounding areas. TGWI provides propane distribution services to approximately 2,400 customers in the Whistler area.

Earnings: The Terasen Gas companies reported $50 million in earnings from the date of acquisition on May 17, 2007. Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is ultimately used for space heating. Virtually all of the earnings of the Terasen Gas companies are generated in the first and fourth quarters. Performance was consistent with that expected to be achieved by the Terasen Gas companies during the period and with operating performance achieved during the same period last year. Results during the period included a $7 million after-tax gain on the sale of surplus land.

As a result of the operation of British Columbia Utilities Commission ("BCUC")-approved regulatory deferral mechanisms, changes in consumption levels and the commodity cost of natural gas do not materially impact the earnings of the Terasen Gas companies. These mechanisms accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers and also accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. Additionally, the Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Gas Volumes: Gas volumes from the date of acquisition were 118,309 TJ. On an annual basis, gas volumes were 220,977 TJ, up 5.7 per cent from 209,013 TJ in 2006. The increase in annual gas volumes was due to cooler weather and growth in the number of customers. Increased volumes result in both higher revenue and natural gas costs and generally do not have a material impact on the earnings of the Terasen Gas companies.

Net customer additions at TGI were 9,939 during 2007 compared to 10,289 net customer additions during 2006. Though 2007 was another strong year for housing starts in British Columbia, adverse weather conditions slowed construction activity late in the year. In addition, growth in multi-family housing impacted net additions as natural gas usage is less prevalent in this type of dwelling. Net customer additions at TGVI were 3,922 during 2007 compared to 4,120 net customer additions during 2006.

Following the acquisition of Terasen by the Corporation, Standard & Poor's ("S&P") raised its unsolicited long-term corporate credit and senior unsecured debt credit ratings on TGI to 'A' from 'BBB' on June 19, 2007.

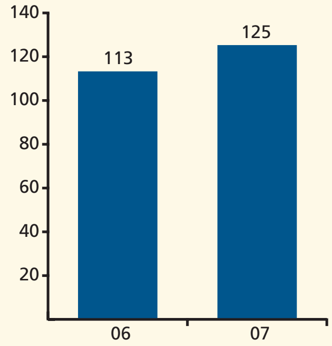
Outlook: TGI's allowed ROE for 2008 has been set at 8.62 per cent, up from 8.37 per cent in 2007. TGVI's allowed ROE for 2008 has been set at 9.32 per cent, up from 9.07 per cent in 2007.

A summary of the forecast gross capital expenditures for 2008 for the Terasen Gas companies is provided under the heading "Capital Program".

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings during 2007 were $125 million (2006 – $113 million), which represented approximately 61 per cent (2006 – 83 per cent) of the Corporation's total regulated earnings. Regulated Electric Utilities – Canadian assets were $4.2 billion as at December 31, 2007 (December 31, 2006 – $3.9 billion), which represented approximately 44 per cent of the Corporation's total regulated assets as at December 31, 2007 (December 31, 2006 – 82 per cent).

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



FortisAlberta

Financial Highlights

Years Ended December 31st	2007	2006	Variance
Energy Deliveries *(GWh)*	**15,378**	14,851	527
($ millions)			
Revenue	**270**	251	19
Operating Expenses	**122**	115	7
Amortization	**75**	69	6
Finance Charges	**36**	30	6
Corporate Tax Recovery	**(11)**	(5)	(6)
Earnings	**48**	42	6

Earnings: FortisAlberta's earnings in 2007 were $6 million higher than last year, primarily due to higher revenue associated with customer growth, and increased corporate income tax recovery, partially offset by higher operating expenses, amortization costs and finance charges.

Energy Deliveries: Energy deliveries increased 527 gigawatt hours ("GWh"), or 3.5 per cent, year over year due to increased energy demand related to customer growth. The Company added approximately 18,000 customers during the year, bringing the total number of customers at FortisAlberta to more than 448,000.

Revenue: Revenue in 2007 was $19 million higher than last year due to an increase of $11 million resulting from customer growth and the 0.7 per cent increase in distribution rates billed to customers, effective January 1, 2007; an increase of $3 million resulting from differences in the impact of various distribution revenue deferrals; increased franchise fee revenue of $1 million; higher net transmission revenue of $1 million largely related to increased energy deliveries, number of customers and Alberta Electric System Operator ("AESO") billing and deferral adjustments; and increased miscellaneous revenue of $3 million. The increase in miscellaneous revenue was primarily due to penalties associated with early termination of distribution service by customers, increased third-party contract work and interest earned on AESO Charges Deferral Accounts.

Expenses: Operating expenses in 2007 were $7 million higher than last year, primarily due to higher labour, employee-benefit and contracted manpower costs and material purchases, partially offset by increased amounts charged to capital projects.

Amortization costs in 2007 were $6 million higher than last year, due to an increase in capital assets driven by load growth, and upgrades and replacements of assets within the Company's service territory, partially offset by amortization of increased customer contributions.

Finance charges in 2007 were $6 million higher than last year, primarily due to increased debt levels to finance capital spending. On January 3, 2007, FortisAlberta issued $110 million 4.99% senior unsecured debentures, maturing January 3, 2047. On April 21, 2006, FortisAlberta issued $100 million 5.40% senior unsecured debentures, maturing April 21, 2036. The net proceeds of the debenture issues were largely used to repay existing credit-facility borrowings that were incurred primarily to fund capital expenditures.

Corporate tax recovery in 2007 was $6 million higher than last year, primarily due to a future income tax recovery in 2007 resulting from the reduction of AESO deferral amounts upon which future income tax is calculated, partially offset by higher current income taxes resulting from a decrease in deductions taken for income tax purposes compared to amounts taken for accounting purposes in 2007 as compared to 2006.

Outlook: FortisAlberta's allowed ROE for 2008 has been set at 8.75 per cent, up from 8.51 per cent in 2007. In February 2008, FortisAlberta received regulatory approval of the Negotiated Settlement Agreement ("NSA") pertaining to the Company's 2008 and 2009 electricity rates. The approved NSA provides for distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009.

A summary of FortisAlberta's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

FortisBC

Financial Highlights

Years Ended December 31st	**2007**	2006	Variance
Electricity Sales *(GWh)*	**3,091**	3,038	53
($ millions)			
Revenue	**229**	216	13
Energy Supply Costs	**67**	68	(1)
Operating Expenses	**69**	63	6
Amortization	**31**	28	3
Finance Charges	**26**	23	3
Corporate Taxes	**5**	7	(2)
Earnings	**31**	27	4

Earnings: FortisBC's earnings in 2007 were $4 million higher than last year, driven by increased electricity rates, higher electricity sales and lower energy supply costs and corporate taxes, partially offset by increased operating expenses, amortization costs and finance charges.

Electricity Sales: Electricity sales increased 53 GWh, or 1.7 per cent, year over year. The favourable impact on electricity sales of a reduction in the estimate of electricity system losses and growth in the number of customers in the residential and general service sectors more than offset the impact of reduced industrial loads associated with a plant optimization by a significant industrial customer. During the first quarter of 2007, an analysis of electricity system losses resulted in a reduction of the estimate of system losses, effective January 1, 2007. The reduction in the system losses reflects efficiency improvements arising from the Company's ongoing capital program of upgrading and replacing generation and T&D systems, as well as the refinement of the process for estimating system losses.

Revenue: Revenue in 2007 was $13 million higher than last year, primarily due to a 1.2 per cent increase in electricity rates, effective January 1, 2007; an incremental 2.1 per cent increase in electricity rates, effective April 1, 2007, including the accrual during the first quarter of 2007 of the 2.1 per cent increase in electricity rates to be collected from customers in 2008; higher revenue contributions from non-regulated operating, maintenance and management services; increased electricity sales for the year due to the reasons described above; and a decrease in performance-based rate-setting ("PBR") incentive adjustments owing to customers.

Expenses: Energy supply costs in 2007 were $1 million lower than last year. Despite having a higher proportion of purchased energy versus energy generated from Company-owned hydroelectric generating plants during 2007, energy supply costs decreased due to lower average power purchase prices.

Operating expenses in 2007 were $6 million higher than last year. The increase was driven by higher operating expenses associated with non-regulated operating, maintenance and management services; general inflationary cost increases; higher labour costs; an increase in the allowance for doubtful accounts associated with forestry-sector customers; and increased property taxes. The increase in operating expenses was partially offset by lower wheeling and water fees and the impact of increased capitalized overhead costs.

Amortization costs in 2007 were $3 million higher than last year, due to an increase in the capital assets of FortisBC related to its capital spending program.

Finance charges in 2007 were $3 million higher than last year, driven by increased borrowings to finance the Company's capital spending program. On July 4, 2007, FortisBC issued $105 million 5.90% senior unsecured debentures, maturing July 4, 2047. The net proceeds of the debenture issue were used largely to repay existing credit-facility borrowings that were incurred primarily to fund capital expenditures.

On June 21, 2007, Moody's Investors Service upgraded the credit rating on FortisBC's senior unsecured debt to 'Baa2, Stable Outlook' from 'Baa3, Stable Outlook'.

Corporate taxes in 2007 were $2 million lower than last year, primarily due to higher deductions taken for corporate income tax purposes compared to amounts taken for accounting purposes, partially offset by higher earnings before corporate taxes.

Outlook: FortisBC's allowed ROE for 2008 has been set at 9.02 per cent, up from 8.77 per cent in 2007. In December 2007, FortisBC received regulatory approval of the NSA pertaining to the Company's 2008 electricity rates, resulting in an increase in electricity rates of 2.9 per cent effective January 1, 2008.

In the second half of 2008, the Company intends on filing with the BCUC a 2009 and 2010 Capital Plan and a 2009 Revenue Requirements Application.

A summary of FortisBC's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31st	**2007**	2006	Variance
Electricity Sales *(GWh)*	**5,093**	4,995	98
($ millions)			
Revenue	**490**	421	69
Energy Supply Costs	**327**	256	71
Operating Expenses	**53**	54	(1)
Amortization	**34**	33	1
Finance Charges	**33**	33	–
Corporate Taxes	**12**	14	(2)
Non-Controlling Interest	**1**	1	–
Earnings	**30**	30	–

Earnings: Newfoundland Power's 2007 earnings of $30 million were comparable to last year. The impact of increased electricity sales was largely offset by the impact of reduced electricity rates due to a reduction in the allowed ROE for 2007.

Electricity Sales: Electricity sales increased 98 GWh, or 2.0 per cent, year over year, primarily due to customer growth and an increase in average consumption.

Revenue: Revenue in 2007 was $69 million higher than last year. The increase was primarily due to the flow through of higher purchased power costs from Newfoundland Hydro, effective January 1, 2007, and increased electricity sales, partially offset by a decrease in electricity rates, effective January 1, 2007, due to a lower allowed ROE for 2007.

Expenses: Energy supply costs in 2007 were $71 million higher than last year, primarily due to the flow through of higher purchased power costs from Newfoundland Hydro, effective January 1, 2007, and increased electricity sales.

Operating expenses in 2007 were $1 million lower than last year. The decrease was primarily due to lower pension costs, reflecting improved returns on higher levels of plan assets attributable to pension funding, and the conclusion, in March 2007, of the amortization of retirement allowances associated with a 2005 Early Retirement Program. The decrease in operating expenses was partially offset by higher labour costs, reflecting both normal wage increases and costs incurred to repair major storm damage to certain distribution systems in December 2007.

Amortization costs in 2007 were $1 million higher than last year, primarily due to the continued investment in capital assets.

Finance charges in 2007 were comparable to last year. On August 17, 2007, Newfoundland Power issued $70 million 5.901% first mortgage sinking fund bonds, maturing August 17, 2037. The net proceeds were used to repay existing credit-facility borrowings, incurred principally to fund capital expenditures, and to retire $31.5 million of maturing 11.875% bonds.

Corporate taxes in 2007 were $2 million lower than last year. The decrease reflected lower earnings before corporate taxes and higher deductions taken for corporate income tax purposes compared to deductions taken for accounting purposes. The higher tax deductions largely related to increased capital cost allowance driven by capital expenditures associated with the Company's Rattling Brook hydroelectric plant during 2007.

Outlook: Newfoundland Power's allowed ROE for 2008 has been set at 8.95 per cent, up from 8.60 per cent in 2007. In December 2007, Newfoundland Power received regulatory approval of the NSA pertaining to 2008 electricity rates, resulting in an average increase in electricity rates of 2.8 per cent effective January 1, 2008.

As a result of a new purchased-power rate structure, effective January 1, 2007, Newfoundland Power paid more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months in 2007 compared to 2006. For 2007, quarterly earnings were not impacted by this change as the Company recorded purchased power based on the forecast annual unit cost per kWh with quarterly variances deferred to a regulatory deferral account. Beginning on January 1, 2008, this regulated account is no longer in effect. As a result, quarterly earnings in 2008 will reflect a seasonal shift from that experienced in 2007. Earnings are expected to be lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007.

A summary of Newfoundland Power's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

Other Canadian Electric Utilities [(1)]

Financial Highlights

Years Ended December 31st	2007	2006	Variance
Electricity Sales *(GWh)*			
Maritime Electric	**1,035**	999	36
FortisOntario	**1,174**	1,169	5
Total	**2,209**	2,168	41
($ millions)			
Revenue	**263**	252	11
Energy Supply Costs	**174**	171	3
Operating Expenses	**29**	28	1
Amortization	**17**	15	2
Finance Charges	**17**	15	2
Corporate Taxes	**10**	9	1
Earnings	**16**	14	2

(1) Includes Maritime Electric and FortisOntario

Earnings: Earnings from Other Canadian Electric Utilities in 2007 were $2 million higher than last year, driven by a one-time $3 million ($2 million after-tax) gain at FortisOntario, related to a refund received as ordered by the regulator associated with an interconnection arrangement, and increased electricity sales and basic electricity rates, partially offset by higher operating expenses, amortization costs and finance charges.

Electricity Sales: Electricity sales increased 41 GWh, or 1.9 per cent, year over year. The increase was driven by higher average consumption due to cooler-than-normal weather conditions experienced on PEI and in Ontario and an increase in the number of customers at Maritime Electric, partially offset by the impact of the loss of a major industrial customer and a temporary shutdown of operations of an industrial customer in Ontario.

Revenue: Revenue in 2007 was $11 million higher than last year, primarily due to increased electricity sales; the $3 million refund received at FortisOntario; a 3.35 per cent increase in basic electricity rates at Maritime Electric, effective July 1, 2006; the impact of an increase in rates at FortisOntario associated with the flow through to customers of higher energy supply costs; and increases in basic distribution rates at FortisOntario in May 2006 and May 2007.

Expenses: Energy supply costs in 2007 were $3 million higher than last year, driven by increased market energy prices paid at FortisOntario and increased electricity sales. At Maritime Electric, actual energy supply costs above or below the regulator-approved amount of 6.73 cents per kWh are deferred for future recovery from, or refund to, customers over a 12-month rolling period.

Operating expenses in 2007 were $1 million higher than last year, driven by costs associated with an early retirement program at FortisOntario and higher insurance, regulatory and legal costs.

Amortization costs in 2007 were $2 million higher than last year, primarily due to continued investment in capital assets.

Finance charges in 2007 were $2 million higher than last year, due to borrowings required to finance capital spending and higher energy supply costs at Maritime Electric.

Corporate taxes in 2007 were $1 million higher than last year, driven by higher earnings before corporate taxes, partially offset by higher deductions taken for corporate income tax purposes compared to deductions taken for accounting purposes.

Outlook: Maritime Electric's maximum allowed ROE for 2008 has been set at 10.00 per cent compared to 10.25 per cent in 2007. In January 2008, the Island Regulatory and Appeals Commission ("IRAC") approved a 1.8 per cent increase in basic customer rates, effective April 1, 2008.

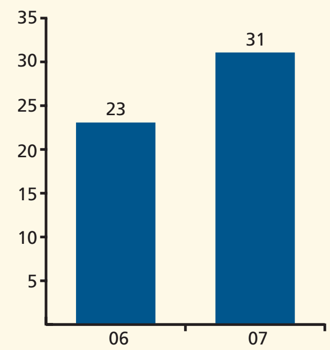
FortisOntario's allowed ROE for 2008 is 9.00 per cent, unchanged from 2007. In 2006, the Ontario Energy Board ("OEB") announced its multi-year electricity distribution rate-setting plan for the years 2007 through 2010. The plan maintains the current cost of capital and introduces an inflation measure coupled with a productivity factor for rate-setting purposes. Over the three-year period, distributors will be required, in three tranches, to submit a full cost-of-service application, which will result in the rebasing of distribution rates. In late 2008, Canadian Niagara Power is expecting to file for rate rebasing for 2009.

A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2008 is provided under the heading "Capital Program".

Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean during 2007 was $31 million (2006 – $23 million), which represented approximately 15 per cent (2006 – 17 per cent) of the Corporation's total regulated earnings. Regulated Electric Utilities – Caribbean assets were $778 million as at December 31, 2007 (December 31, 2006 – $828 million), which represented approximately 8 per cent of the Corporation's total regulated assets as at December 31, 2007 (December 31, 2006 – 18 per cent).

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



Regulated Electric Utilities – Caribbean[1]

Financial Highlights

Years Ended December 31st	2007	2006[2]	Variance
Average US:CDN Exchange Rate[3]	**1.07**	1.13	(0.06)
Electricity Sales *(GWh)*			
Belize Electricity	**382**	360	22
Caribbean Utilities	**527**	485[4]	42
Fortis Turks and Caicos	**145**	125[4]	20
Total	**1,054**	970	84
($ millions)			
Revenue	**307**	101	206
Equity Income	**–**	10	(10)
Energy Supply Costs	**169**	57	112
Operating Expenses	**49**	13	36
Amortization	**28**	7	21
Finance Charges	**15**	5	10
Corporate Taxes	**2**	2	–
Non-Controlling Interest	**13**	4	9
Earnings	**31**	23	8

(1) Includes Belize Electricity, in which Fortis holds a 70.1 per cent controlling interest; Caribbean Utilities, in which Fortis holds an approximate 54 per cent controlling interest; and wholly owned Fortis Turks and Caicos.

(2) Revenue and expenses for the 12 months ended December 31, 2006 do not include revenue and expenses related to Caribbean Utilities, as this utility was not consolidated in the financial statements of Fortis during this period. Revenue and expenses for the 12 months ended December 31, 2006 include revenue and expenses related to Fortis Turks and Caicos from August 28, 2006, the date of acquisition by Fortis. In 2006, equity income related to the Corporation's previous approximate 37 per cent investment interest in Caribbean Utilities accounted for on an equity basis.

(3) The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00 = US$1.00. The reporting currency of Caribbean Utilities is the Cayman Island dollar, which is pegged to the US dollar at CI$0.84 = US$1.00. The reporting currency of Fortis Turks and Caicos is the US dollar.

(4) Full year sales as reported by the utility.

On November 7, 2006, Fortis acquired an additional approximate 16 per cent interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent interest in Caribbean Utilities accounted for on an equity basis on a two-month lag. Caribbean Utilities has an April 30th fiscal year end and, therefore, the data presented above for 2007 and 2006 includes financial results for Caribbean Utilities for the 12-month periods ended October 31st.

Earnings: Earnings' contribution from Regulated Electric Utilities – Caribbean in 2007 was $8 million higher than last year. The increase was driven by the first full year of earnings' contribution from Fortis Turks and Caicos, and higher electricity sales and lower finance charges at Belize Electricity, partially offset by the unfavourable impact of foreign currency translation. The impact of the increased investment in Caribbean Utilities to approximately 54 per cent was offset by the impact of lower earnings reported at Caribbean Utilities driven by a charge associated with the disposal of steam-turbine assets and higher operating expenses. The charge on disposal of the steam-turbine assets reduced earnings of Fortis by approximately $2 million in 2007. Earnings' contribution from Regulated Electric Utilities – Caribbean was tempered by the $2 million unfavourable impact of foreign exchange associated with translation of foreign currency-denominated earnings, due to strengthening of the Canadian dollar against the US dollar. During 2007, the contribution to earnings by Caribbean Utilities, Belize Electricity and Fortis Turks and Caicos was $9 million, $12 million and $10 million, respectively.

Electricity Sales: Total electricity sales reported by Regulated Electric Utilities – Caribbean increased 84 GWh, or 8.7 per cent, year over year. The increase was primarily due to higher demand, driven by customer growth, as strong local economies fuelled new residential and commercial construction. Growth in electricity sales reported at Fortis Turks and Caicos was led by large hotels; however, the rate applicable to this customer class is the lowest of all customer classes of Fortis Turks and Caicos. Significant projects

under construction on the Turks and Caicos Islands include a US$68 million expansion of the Beaches Resort & Spa; the Seven Stars Luxury resort; the 255,870-square foot Emerald Point Condominium and Resort; and the 220,440-square foot Alexandra Resort and Residences. Commercial growth on Grand Cayman is being led by new developments, including the 60,000-square foot Bank of Butterfield building, expected to come on line in early 2008, and the 160,000-square foot Governor's Square shopping and office centre, the 89,000-square foot Caribbean Club condominium complex and the 500,000-square foot phase-one of Camana Bay, each of which came on line during 2007.

Revenue: In addition to the impact of consolidating Caribbean Utilities' financial results during 2007, revenue increased year over year due to the impact of the first full year of ownership of Fortis Turks and Caicos, electricity sales growth at Belize Electricity and Fortis Turks and Caicos, and a 3.7 per cent increase in the value-added component of customer rates, effective July 1, 2007, at Belize Electricity. The increase was partially offset by the impact of foreign currency translation.

Expenses: The increase in expenses in 2007 over 2006 was significantly impacted by the consolidation of Caribbean Utilities' financial results during 2007 and the impact of the first full year of ownership of Fortis Turks and Caicos, partially offset by the impact of foreign currency translation.

Operating expenses and amortization costs at Belize Electricity increased year over year, due to higher employee costs, new customer service and revenue loss reduction initiatives, and general increases in the cost of goods and services. Amortization costs increased due to continued investment in capital assets. Finance charges at Belize Electricity were lower than last year due to lower debt balances. In June 2006, proceeds from a share offering at Belize Electricity were used to repay certain trade payables and inter-company loans, and drawings on overdraft facilities incurred primarily to finance the high cost of power and fuel.

Operating expenses reported at Fortis Turks and Caicos in 2007 increased over last year, due to the impact of increased activity associated with a high-growth environment.

Caribbean Utilities' operating expenses consolidated in the financial results of the Corporation during 2007 were higher than operating expenses reported by Caribbean Utilities in 2006, driven by higher generation and T&D maintenance costs, and by operating expenses during the second quarter of 2006 being reduced by a $1.4 million (US$1.2 million) gain on disposal of assets associated with an insurance settlement. Additionally, during the first quarter of 2007, Regulated Electric Utilities – Caribbean operating expenses included a $4.4 million (US$3.7 million) charge on the disposal of Caribbean Utilities' steam-turbine assets. Caribbean Utilities' amortization costs consolidated in the financial results of the Corporation during 2007 were higher than amortization costs reported by Caribbean Utilities during 2006, due to continued investment in capital assets, including the addition of a new 16-MW diesel-fired generating unit commissioned in June 2007. The generating unit increased Caribbean Utilities' total installed generating capacity to approximately 137 MW.

Caribbean Utilities closed the US$30 million first tranche of a US$40 million 5.65% senior unsecured note offering in June 2007 and closed the second tranche of US$10 million in November 2007. The senior unsecured notes are due June 1, 2022. The proceeds from the debt offering were used to repay debt and to finance capital expenditures.

During 2007, Fortis Turks and Caicos commissioned an additional 7 MW of owned generating capacity, bringing the combined generating capacity at Fortis Turks and Caicos to 48 MW at the end of the year. In May 2007, Fortis Turks and Caicos purchased four additional generating units with a combined capacity of 13 MW, which are expected to be installed and commissioned during 2008 and 2009. The additional capacity is intended to keep pace with strong customer growth.

Outlook: Strong electricity sales growth experienced by the Regulated Electric Utilities – Caribbean segment during 2007 is expected to continue in 2008.

During the first half of 2008, the Government of the Cayman Islands is expected to issue a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence to Caribbean Utilities. Under the proposed new licences, customer rates will be set using an initial targeted ROA of 10 per cent, down from 15 per cent as permitted under the existing licence. Additional information on the impact of the proposed new licences is provided under the heading "Regulatory Highlights".

Electricity rates at Belize Electricity have been approved for the period from July 1, 2007 through June 30, 2008. While the value-added component of electricity rates has increased, average electricity rates remain unchanged.

A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2008 is provided under the heading "Capital Program".

NON-REGULATED

Non-Regulated – Fortis Generation

Fortis Generation consists of the Corporation's investment in non-regulated generation assets. The following table provides a summary of the Corporation's non-regulated generation assets by location.

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

Financial Highlights

Years Ended December 31st	2007	2006	Variance
Energy Sales *(GWh)*			
Belize	**167**	178	(11)
Ontario	**707**	722	(15)
Central Newfoundland	**137**	168	(31)
British Columbia	**34**	30	4
Upper New York State	**77**	105	(28)
Total	**1,122**	1,203	(81)
($ millions)			
Revenue	**75**	80	(5)
Energy Supply Costs	**8**	6	2
Operating Expenses	**14**	15	(1)
Amortization	**10**	11	(1)
Finance Charges	**10**	10	–
Corporate Taxes	**8**	8	–
Non-Controlling Interest	**1**	3	(2)
Earnings	**24**	27	(3)

Earnings: Earnings from Non-Regulated – Fortis Generation in 2007 were $3 million lower than last year. The decrease was primarily due to decreased production due to lower rainfall, partially offset by higher average wholesale energy prices in Ontario and decreased operating expenses.

Energy Sales: Energy sales decreased 81 GWh, or 6.7 per cent, year over year. The decrease was primarily due to lower production as a result of lower rainfall in most of the operating regions; however, rainfall in 2006 was generally above normal levels. Production in Belize in 2007 and 2006 was above expected levels based on historical average rainfall. The decrease in energy sales was partially offset by the impact of a full year of operations of the Dolgeville plant in Upper New York State in 2007 compared to nine months of operation in 2006 as a result of a disruption of water supply due to flooding during that year.

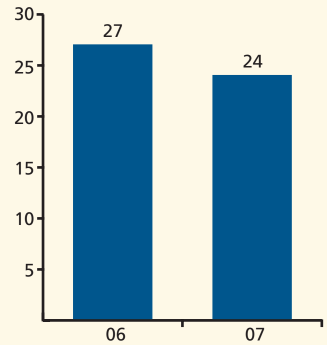
Revenue: Revenue in 2007 was $5 million lower than last year, driven by decreased production, partially offset by higher average wholesale energy prices in Ontario and the flow through of increased energy supply-related costs in central Newfoundland.

The average wholesale energy price per MWh in Ontario during 2007 was $47.81 compared to $46.38 last year. The increase in average wholesale energy prices in Ontario resulted in an increase in revenue in 2007 of approximately $1 million compared to last year.

Expenses: Operating expenses in 2007 were $1 million lower than last year, driven by the receipt of insurance proceeds in 2007 associated with costs expensed late in 2006 related to the flood at the Dolgeville plant and the reallocation of costs from non-regulated Ontario generation operations to regulated Ontario electricity operations.

Outlook: Construction of the 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize commenced during 2007. The facility is expected to come into service late in 2009. Earnings' contribution from the Vaca facility is expected to partially offset a loss of earnings upon the expiration, in 2009, of the Niagara Exchange Agreement associated with the Rankine Generating Station in Ontario.

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



Further information on the Vaca hydroelectric facility and a summary of forecast non-regulated utility capital expenditures for 2008 is provided under the heading "Capital Program".

Non-Regulated – Fortis Properties

Fortis Properties consists of the Corporation's investment in non-regulated commercial real estate and hotel assets.

Financial Highlights

Years Ended December 31st

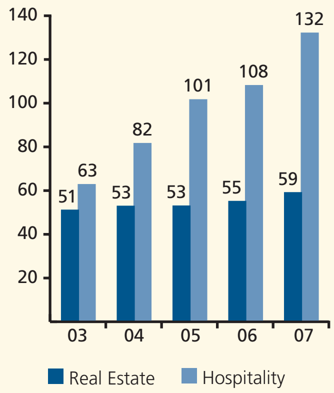
($ millions)	**2007**	2006	Variance
Real Estate Revenue	**59**	55	4
Hospitality Revenue	**132**	108	24
Total Revenue	**191**	163	28
Operating Expenses	**123**	105	18
Amortization	**14**	12	2
Finance Charges	**24**	21	3
Gain on Sale of Property	**–**	(2)	2
Corporate Taxes	**6**	8	(2)
Earnings	**24**	19	5

Earnings: Fortis Properties' earnings in 2007 were $5 million higher than last year. Excluding a $4 million favourable corporate tax adjustment in 2007 and excluding $3 million associated with a favourable corporate tax adjustment and a gain on the sale of Days Inn Sydney in 2006, earnings in 2007 were $4 million higher than last year, driven by expanded hospitality operations in western Canada.

On August 1, 2007, Fortis Properties purchased the Delta Regina in Saskatchewan for approximately $50 million, including acquisition costs. Delta Regina is comprised of 274 hotel rooms, the Saskatchewan Trade and Convention Centre, 52,000 square feet of Class A commercial office space and a parking garage. On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia for approximately $52 million, including acquisition costs and assumed debt, increasing hospitality operations by 454 rooms.

Revenue: Real estate revenue in 2007 was $4 million higher than last year, due to the expanded Blue Cross Centre in Moncton, revenue from the Delta Regina associated with real estate operations and growth experienced in all operating regions of the Company. The occupancy rate of the Real Estate Division was 96.8 per cent as at December 31, 2007, up from 94.9 per cent as at December 31, 2006, due to additional leasing in all operating regions of the Company.

Fortis Properties
Revenue *($ millions)*



Hospitality revenue in 2007 was $24 million higher than last year, $23 million of which was due to growth in the Company's hospitality operations in western Canada, $1 million of which was due to increased revenue earned from the expanded Ontario hotels and $1 million of which was due to increased revenue earned from the Company's hospitality operations in Atlantic Canada. The increases were partially offset by the impact of the elimination of revenue following the sale of Days Inn Sydney in June 2006.

Revenue per available room ("REVPAR") in 2007 was $79.31 compared to $72.67 in 2006. The increase in REVPAR was primarily attributable to the addition of the four hotels in western Canada acquired on November 1, 2006 and the Delta Regina acquired on August 1, 2007.

Expenses: Operating expenses in 2007 were $18 million higher than last year. The increase was primarily due to expanded operations and general inflationary cost pressures driven by the Company's hospitality operations in western Canada and the expanded Ontario hotels and Blue Cross Centre. The increase was partially offset by the elimination of operating expenses following the sale of Days Inn Sydney in June 2006.

Finance charges in 2007 were $3 million higher than last year, primarily due to financings associated with the four hotels in western Canada acquired on November 1, 2006 and the Delta Regina acquired on August 1, 2007.

Corporate taxes in 2007 were $2 million lower than last year. Corporate taxes during 2007 were reduced by a $4 million favourable adjustment resulting from enacted future federal income tax rate reductions. Corporate taxes during 2006 were reduced by approximately $2 million, also the result of future federal income tax rate reductions.

Outlook: Fortis Properties' Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure. There is a continued focus in this Division on a strategy of early tenant renewals.

Fortis Properties' Hospitality Division currently operates in eight Canadian provinces. The hospitality industry is impacted by economic factors such as fluctuating energy costs and increasing municipal taxes. Increased supply of hotel rooms in many of the markets in which the Hospitality Division operates has created competitive challenges in recent years and will continue to do so in 2008. The Hospitality Division operates in the mid-to-upper market which targets a large customer base, allowing the Company to reduce exposure to risk associated with a specific market segment.

Corporate and Other (1)

Financial Highlights

Years Ended December 31st

($ millions)	**2007**	2006	Variance
Total Revenue	**22**	9	13
Operating Expenses	**13**	11	2
Amortization	**6**	3	3
Finance Charges (2)	**70**	41	29
Foreign Exchange Gain	**–**	(2)	2
Corporate Tax Recovery	**(12)**	(11)	(1)
Preference Share Dividends	**6**	2	4
Net Corporate and Other Expenses	**(61)**	(35)	(26)

(1) Includes non-regulated Terasen corporate-related activities and financial results of CWLP from May 17, 2007, the date of acquisition

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

The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CWLP. CWLP is a non-regulated shared-service business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting.

Net corporate and other expenses in 2007 were $26 million higher than last year, driven by Terasen acquisition-related finance charges.

Revenue in 2007 was $13 million higher than last year. The increase was primarily due to the inclusion of revenue from CWLP of $8 million from the date of acquisition and higher inter-company interest revenue due to increased inter-company lending.

Operating expenses in 2007 were $2 million higher than last year; however, operating expenses last year included $1.7 million in business development costs. Excluding this item, operating expenses in 2007 were almost $4 million higher than last year, driven largely by Terasen corporate and CWLP operating expenses.

The increase in finance charges year over year was driven by Terasen acquisition-related finance charges of approximately $25 million from the date of acquisition; increased credit-facility borrowings in support of general corporate activities; and interest on US$40 million of unsecured subordinated convertible debentures issued in November 2006 to fund, in part, the increased investment in Caribbean Utilities. The increase was partially offset by the impact of lower foreign exchange translation associated with US dollar-denominated interest payments.

An approximate $2 million ($1.7 million after-tax) foreign exchange translation gain on unhedged corporate US dollar-denominated debt was recorded in 2006. There was no similar foreign exchange translation gain during 2007, as all corporate US dollar-denominated debt has been designated as a hedge against the Corporation's US dollar-denominated foreign net investments. During 2007, all foreign exchange translation gains and losses on corporate US dollar-denominated debt in effective hedging relationships were recorded in other comprehensive income.

Corporate tax recovery in 2007 was $1 million higher than last year, due to the impact of higher tax-deductible corporate expenses, partially offset by the impact of lower enacted future federal income tax rates on future income tax assets.

The increase in preference share dividends year over year was associated with the First Preference Shares, Series F issued on September 28, 2006.

In September 2007, Fortis privately placed US$200 million 6.60% senior unsecured notes, due September 2037. The net proceeds were used to refinance existing credit-facility indebtedness associated with the Terasen acquisition and for general corporate purposes.

Regulatory Highlights

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity *(%)*	Allowed Returns *(%)* 2006	2007	2008	Supportive Features: Future or Historical Test Year Used to Set Rates
				ROE		COS[1]/ROE
						PBR mechanism through 2009:
TGI	BCUC	35	8.80	8.37	8.62	TGI: 50/50 sharing of earnings above or below the allowed ROE.
TGVI	BCUC	40	9.50	9.07	9.32	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs.
						ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisBC	BCUC	40	9.20	8.77	9.02	COS/ROE
						PBR mechanism through 2008, with option to continue in 2009 – 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	Alberta Energy and Utilities Board ("AEUB") (to December 31, 2007)	37	8.93	8.51	8.75	COS/ROE
	Alberta Utilities Commission ("AUC") (effective January 1, 2008)					ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.24 +/– 50 bps	8.60 +/– 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	10.25	10.00	COS/ROE
						Future Test Year
FortisOntario	OEB (Canadian Niagara Power)	50	9.00	9.00	9.00	Canadian Niagara Power – COS/ROE
	Franchise Agreement (Cornwall Electric)					Cornwall Electric – Price cap with commodity cost flow through
						Historical Test Year
				ROA		Four-year COS/ROA agreements with market-based returns
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00 – 15.00	10.00 – 15.00	Future Test Year
Caribbean Utilities	Electricity Regulatory Authority (effective 2008 under proposed new licences)	N/A	15.00	15.00	10.00[2]	COS/ROA
						Price-cap adjustment mechanism tied to consumer price indices (effective 2008 under proposed new 20-year licences)
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50	17.50	17.50	COS/ROA
						Future Test Year

(1) Cost of service (2) As per proposed new licences

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI and TGVI	• March 2007, BCUC approval of extension of PBR mechanisms through 2009 for both TGI and TGVI. • November 2007, TGVI received conditional BCUC approval for the construction of a 1.5 billion-cubic foot liquefied natural gas ("LNG") storage facility on Vancouver Island for a total estimated cost of between $175 million and $200 million. • BCUC approval of various rates at TGI, 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 reflect the impact of an increase in the allowed ROE for 2008 to 8.62 per cent.
FortisBC	• December 2006, BCUC approval of a 1.2 per cent increase in customer rates, effective January 1, 2007. • March 2007, BCUC order changing the treatment of financing costs associated with large capital projects during the period of construction. Result was an additional 2.1 per cent increase in 2007 customer rates, effective April 1, 2007. The impact of the increase in electricity rates relating to the period January 1, 2007 through March 31, 2007 will be recovered in 2008 customer rates. The amount to be recovered was accrued in the first quarter of 2007. • Preliminary 2008 Revenue Requirements Application filed on October 1, 2007 and updated by FortisBC on November 1, 2007. • December 2007, BCUC approval of an NSA associated with 2008 revenue requirements resulting in a rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's extensive capital investment program and higher power purchase costs due to ongoing customer growth and increased electricity demand. Rates for 2008 reflect an allowed ROE of 9.02 per cent. • BCUC-approved NSA included updated 2007 gross capital expenditures of approximately $147 million for 2007 and $132 million for 2008. • FortisBC intends on filing a 2009 and 2010 Capital Plan and a 2009 Revenue Requirements Application with the BCUC in the second half of 2008.
FortisAlberta	• June 2006, AEUB-approved 2006/2007 NSA associated with 2006/2007 revenue requirements, providing for a 0.7 per cent distribution rate increase, effective January 1, 2007. • AEUB initially approved 2007 distribution revenue requirements based on an allowed ROE of 8.93 per cent. The ROE was reduced to 8.51 per cent, effective January 1, 2007, due to the impact of lower long-term Canada bond yields on the automatic adjustment formula used to calculate the allowed ROE. As a result of the lower allowed ROE, FortisAlberta will refund to customers in 2008 rates approximately $1 million of revenue collected in base rates in 2007. • June 2007, AEUB approval to sell amounts in annual AESO Charges Deferral Account. In September 2007, approximately $28 million of the 2006 AESO Charges Deferral Account was sold to a Canadian chartered bank for cash consideration of approximately $27 million and a receivable of approximately $1 million, due February 15, 2009. In December 2007, approximately $37 million of the 2007 AESO Charges Deferral Account was sold to a Canadian chartered bank for cash consideration of approximately $36 million and a receivable of approximately $1 million, due February 15, 2010. • June 2007, filing of 2008/2009 revenue requirements requesting an increase in base distribution rates of 8.5 per cent, effective January 1, 2008, and 9.0 per cent, effective January 1, 2009. • November 2007, filing of an NSA associated with 2008/2009 revenue requirements. • December 2007, regulatory approval of interim distribution rates, effective January 1, 2008. • February 2008, regulatory approval of 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 ROE of 8.51 per cent. The impact of the increase in the ROE for 2008 to 8.75 per cent is subject to deferral-account treatment and, as such, will be recognized as earned and is expected to be collected in future customer rates. • Effective January 1, 2008, FortisAlberta is regulated by the AUC due to the separation of the AEUB into two separate regulatory bodies.
Newfoundland Power	• December 2006, PUB approval, on an interim basis, of an average 0.07 per cent increase in customer electricity rates, effective January 1, 2007. The increase was due to a change in the flow through of costs from Newfoundland Hydro, driven by increased purchased power costs and the resulting change in the wholesale purchased power rate, partially offset by the impact of a reduction in Newfoundland Power's allowed ROE to 8.60 per cent, effective January 1, 2007. There was no impact on Newfoundland Power's earnings in 2007 due to the change in the flow through of costs from Newfoundland Hydro. In April 2007, the PUB ordered the final approval of the average 0.07 per cent increase in customer electricity rates, effective January 1, 2007. • December 2006, PUB approval of an application requesting amortization of $2.7 million of unrecognized 2005 unbilled revenue as revenue in 2007 to offset the 2007 income tax impact of changing to the accrual method for revenue recognition, the deferred recovery of capital asset amortization of $5.8 million similar to 2006 and the deferred recovery of $1.8 million associated with the cost of replacement energy required to be purchased while the Company's Rattling Brook hydroelectric generating facility is being refurbished.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• September 2007, PUB approval of 2008 Capital Budget totalling approximately $51 million. • December 2007, PUB approval of NSA associated with 2008 General Rate Application resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase is largely driven by higher amortization costs. The rate increase reflects an allowed ROE of 8.95 per cent for 2008. • PUB approval of the NSA will also result 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 to five years of certain deferred regulatory balances; (iv) for 2008 through 2010, the deferral of variations in purchased 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.
Maritime Electric	• October 2007, IRAC approval of 2008 gross capital expenditures of approximately $19 million. • October 2007, filing for customer rates for the period April 1, 2008 through March 31, 2009, requesting an increase in basic electricity rates of 1.8 per cent. • January 2008, IRAC approval, as filed, of a 1.8 per cent increase in basic electricity rates, effective April 1, 2008, and approval of a maximum allowed ROE of 10.00 per cent for 2008.
FortisOntario	• April 2007, OEB approval of an average 0.9 per cent increase in electricity distribution rates, effective May 1, 2007, for operations in each of Fort Erie, Port Colborne and Gananoque. Increase determined using OEB's incentive rate mechanism, comprised of a 1.9 per cent increase for inflation, partially offset by a 1 per cent decrease for a productivity adjustment. • July 2007, OEB approval for the recovery in customer rates, as requested, of approximately $2 million in extraordinary costs incurred as a result of the snowstorm in October 2006. The extraordinary costs, which had been previously deferred, are being recovered mostly over a period of two years, beginning September 2007.
Belize Electricity	• June 2007, PUC Final Decision on tariffs for the period July 1, 2007 to June 30, 2008 approving changes to tariffs for certain customer classes while maintaining the average electricity rate at BZ44.1 cents per kWh. • Final Decision reflected many recommendations provided by an independent expert who was appointed by the PUC, subsequent to the objection by Belize Electricity and the Government of Belize of the PUC's Initial Decision on the Tariff Application. • Belize Electricity objected to and appealed the Final Decision associated with adjustments for cost of power, commercial loss targets and penalties associated with reliability targets. • In December 2007, amendments to the *Electricity (Tariffs, Charges and Quality of Services Standards) By-Laws* (Belize) affecting the tariff-setting process at Belize Electricity were enacted. The result is a simplified tariff-setting methodology allowing for improved rate stabilization. The amendments settled outstanding matters related to the PUC's June 2007 Final Decision on tariffs, effective July 1, 2007. • The overall average electricity rate of BZ44.1 cents per kWh remains in effect for the period July 1, 2007 to June 30, 2008. The recovery of the cost of power component of rates remained at BZ25.3 cents per kWh, while the value-added component of rates increased BZ0.6 cents per kWh to BZ16.8 cents per kWh and the component of rates associated with the recovery of rate stabilization accounts decreased BZ0.6 cents per kWh to BZ2.0 cents per kWh.
Caribbean Utilities	• Under its existing licence, Caribbean Utilities was entitled to a 4.5 per cent rate increase, effective August 1, 2007, primarily due to the cost associated with the write-down of the steam-turbine assets, increased operating costs and investment in capital assets. • Basic rate increase not implemented August 1, 2007, due to freezing of basic electricity rates during the period that the Hurricane Ivan cost-recovery surcharge ("CRS") is effective. • An AIP was reached with the Government of the Cayman Islands in December 2007 on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence. The terms of the AIP include competition for future generating capacity and the general promotion of renewable resources. The new licences are expected to be issued in the first half of 2008. • Effective January 1, 2008, as a result of the AIP, basic customer rates were reduced by 3.25 per cent, the CRS was removed and a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, resulting in average monthly savings to residential customers of approximately 15 per cent. The 3.25 per cent reduction in basic rates will reduce annual revenue by approximately US$2 million. Additionally, Caribbean Utilities has forgone US$2.6 million of revenue in 2008 as a result of the early elimination of the CRS. Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review thereafter. • The AIP will see the replacement of the current allowed ROA of 15 per cent with a rate cap and adjustment mechanism based on published consumer price indices. Customer rates will now be set using an initial targeted ROA of 10 per cent beginning in 2008.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2007 and December 31, 2006. The significant changes in the consolidated balance sheets associated with the consolidation of Terasen as at December 31, 2007 are itemized separately below.

Significant Changes in the Consolidated Balance Sheets between December 31, 2007 and December 31, 2006

($ millions)	**Increase due to Terasen**	**Other Increase/ (Decrease)**	**Explanation**
Cash	18	(1)	The other decrease in cash was not significant.
Accounts receivable	349	–	Included in the change associated with Terasen was a $129 million increase in accounts receivable from the date of acquisition as a result of a seasonal increase in sales.
Regulatory assets – current and long-term	146	(5)	The other decrease in regulatory assets was driven by the sale of the majority of FortisAlberta's 2006 AESO Charges Deferral Account, partially offset by an increase in energy costs deferred at Maritime Electric, due to higher energy prices, and the deferral of other post-employment benefit ("OPEB") costs at Newfoundland Power in excess of that expensed under the cash method of accounting. Included in the change associated with Terasen was a $50 million increase in regulatory assets from the date of acquisition, driven by an increase in the fair market value of the gas commodity swap contracts that is deferred in a rate stabilization account.
Inventories of gas, materials and supplies	203	(3)	The other decrease in materials and supplies was not significant. Included in the change associated with Terasen was a $108 million increase in inventories of gas, materials and supplies from the date of acquisition, as a result of the typical seasonal injection of gas into storage.
Deferred charges and other assets	27	(22)	The other decrease in deferred charges and other assets was driven by the reclassification of $21 million of deferred financing costs and $11 million of unamortized deferred losses associated with a previously cancelled forward interest rate swap contract to long-term debt and accumulated other comprehensive loss, respectively, upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007. The decrease was partially offset by an increase in accrued pension assets.
Future income tax assets – long-term	18	12	The other increase in future income tax assets primarily related to the tax impact of costs associated with the issuance of Common Shares upon the conversion of Subscription Receipts on May 17, 2007.
Utility capital assets	2,841	306	The other increase in utility capital assets primarily related to $670 million invested in electricity systems, partially offset by customer contributions, amortization for the 12-month period and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets. Included in the change associated with Terasen was a $73 million net increase in utility capital assets from the date of acquisition, due to capital spending, less amortization for the period.
Income producing properties	–	50	The increase in income producing properties primarily related to the acquisition of the Delta Regina by Fortis Properties on August 1, 2007.
Intangibles, net of amortization	9	(4)	The other decrease in intangibles was not significant. The change in intangibles associated with Terasen primarily related to the fair value of customer contracts at CWLP recorded on acquisition as part of the purchase price allocation, less amortization for the period.
Goodwill	907	(24)	The other decrease in goodwill primarily related to the impact of foreign exchange on the translation of US dollar-denominated goodwill amounts.
Short-term borrowings	376	1	The other increase in short-term borrowings was not significant. Included in the change associated with Terasen was a $100 million increase in short-term borrowings from the date of acquisition, largely driven by seasonality of operations including the impact of increased gas inventories.

Significant Changes in the Consolidated Balance Sheets between December 31, 2007 and December 31, 2006 (cont'd)

($ millions)	Increase due to Terasen	Other Increase/ (Decrease)	Explanation
Accounts payable and accrued charges	409	51	The other increase in accounts payable and accrued charges primarily related to an increase in the amounts owing by FortisAlberta to the AESO for transmission costs and flow through of customer receipts, in addition to the impact of increased capital spending. Included in the change associated with Terasen was a $120 million increase in accounts payable and accrued charges from the date of acquisition, driven by an increase in the fair market value of the gas commodity swap contracts and the timing of payments.
Dividends payable	–	21	The increase in dividends payable was driven by increased Common Shares outstanding associated with the issuance of 5.17 million Common Shares in January 2007 and the issuance of 44.3 million Common Shares in May 2007, upon the completion of the acquisition of Terasen. The increase was also due to a 4-cent increase in the declared quarterly dividend.
Income taxes payable	27	3	The other increase in income taxes payable was not significant. Income taxes payable at Terasen decreased $37 million from $64 million as at the date of acquisition.
Deferred credits	170	12	The other increase in deferred credits was primarily due to an increase in the OPEB liability at Newfoundland Power.
Regulatory liabilities – current and long-term	32	1	The other increase in regulatory liabilities was not significant.
Long-term debt and capital lease obligations (including current portion)	2,077	339	The other increase in long-term debt and capital lease obligations was driven by the issuance of long-term debt and increased net committed credit-facility borrowings. The increase was partially offset by the impact of the early repayment of a US$28.5 million term loan at BECOL; the conversion of US$9 million of the Corporation's 6.75% and 5.5% unsecured subordinated convertible debentures; regular debt repayments; the reclassification of $21 million in deferred financing costs, net of amortization during the period, from deferred charges and other assets, upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007; and the impact of foreign exchange upon the translation of US dollar-denominated debt. The issuance of long-term debt, primarily to repay committed credit-facility borrowings and finance capital expenditures, was comprised of a $110 million senior unsecured debenture offering by FortisAlberta, a $70 million first mortgage sinking fund bond issue by Newfoundland Power, a $105 million senior unsecured debenture offering by FortisBC, and a US$40 million unsecured note issue by Caribbean Utilities. In addition, US$200 million senior unsecured notes were issued by the Corporation, primarily to refinance existing indebtedness associated with the Terasen acquisition and for general corporate purposes. TGI also issued $250 million in unsecured debentures to repay $250 million in long-term debt that matured in October 2007. The net $25 million increase in committed credit-facility borrowings was driven by net drawings of $124 million by the Corporation, partially offset by net reductions of $76 million by FortisAlberta, $2 million by Newfoundland Power and $21 million by FortisBC.
Non-controlling interest	–	(15)	The decrease in non-controlling interest primarily related to the impact of foreign exchange on the translation of US dollar-denominated non-controlling interest amounts.
Shareholders' equity	–	1,325	The increase in shareholders' equity primarily related to the $1.12 billion, net of after-tax expenses, issuance of Common Shares, upon the conversion of Subscription Receipts, to substantially finance the net cash purchase price of Terasen; the $146 million, net of after-tax expenses, issuance of Common Shares in January 2007, combined with net earnings reported for the year, less common share dividends. The increase was partially offset by an increase in accumulated other comprehensive loss driven by the impact of foreign exchange on the translation of the Corporation's net investments in foreign subsidiaries, and a $5 million transitional adjustment to opening accumulated other comprehensive loss upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007.

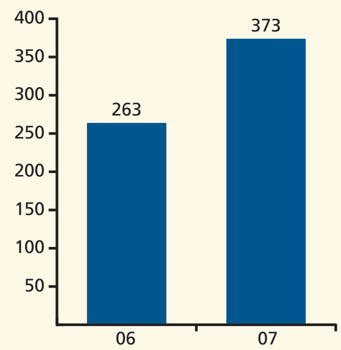
Liquidity

The following table outlines the summary of cash flows.

Years Ended December 31st *($ millions)*	2007	2006	Variance
Cash, beginning of year	**41**	33	8
Cash provided by (used in)			
Operating activities	**373**	263	110
Investing activities	**(2,033)**	(634)	(1,399)
Financing activities	**1,680**	379	1,301
Foreign currency impact on cash balances	**(3)**	–	(3)
Cash, end of year	**58**	41	17

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2007 was $110 million higher than last year. The increase was driven by FortisAlberta, Caribbean Utilities and FortisBC, partially offset by cash used in operating activities at the Terasen Gas companies. The increase in cash from operating activities at FortisAlberta was driven by the sale of amounts in the Company's AESO Charges Deferral Account; the impact of corporate tax refunds received during 2007 compared to corporate taxes paid during 2006; the positive impact of changes in other regulatory deferral accounts; and the timing of accounts receivable and accounts payable. The increase at FortisBC was driven by the timing of accounts receivable and accounts payable. Cash used in operating activities at the Terasen Gas companies was driven by the build-up of gas inventories and accounts receivable from customers from the date of acquisition, due to seasonality of the business, combined with the timing of payment of corporate income taxes. The increase in cash flow from operating activities associated with Caribbean Utilities was the result of the Corporation consolidating the financial results of Caribbean Utilities on a two-month lag basis beginning with the first quarter of 2007, due to increasing its investment to an approximate 54 per cent controlling interest in November 2006. During 2006, Caribbean Utilities was accounted for on an equity basis on a two-month lag.

Cash Flow from Operating Activities
($ millions)



Investing Activities: Cash used in investing activities in 2007 was approximately $1.4 billion higher than last year, primarily due to the acquisition of Terasen on May 17, 2007 for $3.7 billion, including assumed debt of approximately $2.4 billion. This acquisition resulted in a cash payment, including acquisition costs, of approximately $1.25 billion, net of cash acquired. On August 1, 2007, Fortis Properties acquired the Delta Regina for a net cash purchase price of approximately $50 million. Business acquisition activity during 2006 included the acquisition of Fortis Turks and Caicos in August 2006 for a net cash purchase price of approximately $76 million; the acquisition of an additional approximate 16 per cent ownership interest in Caribbean Utilities for a net cash purchase price of approximately $53 million; and the acquisition by Fortis Properties of four hotels in Alberta and British Columbia for a net cash purchase price of approximately $40 million. Cash used in investing activities also increased year over year due to significantly higher utility capital expenditures.

Gross utility capital expenditures in 2007 were $790 million, $307 million higher than last year. The increase was primarily due to capital expenditures incurred at the Terasen Gas companies, Fortis Turks and Caicos and Caribbean Utilities; increased capital spending at FortisAlberta and FortisBC; and the commencement of the construction of the 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize during the second quarter of 2007. Gross utility capital expenditures also increased due to the refurbishment of the Rattling Brook hydroelectric generating facility at Newfoundland Power during 2007.

Contributions received in aid of construction in 2007 were $19 million higher than last year, primarily related to the Terasen Gas companies, as well as increased utility capital expenditures at FortisAlberta and FortisBC.

Financing Activities: Cash provided from financing activities in 2007 was $1.68 billion, approximately $1.3 billion higher than last year.

Proceeds from net short-term borrowings of $103 million during 2007 were driven by net drawings by Terasen, Maritime Electric, Fortis Inc., Fortis Turks and Caicos, and Caribbean Utilities of $100 million, $11 million, $6 million, $5 million and $5 million, respectively, partially offset by the repayment of $22 million of net short-term borrowings by FortisBC with partial proceeds from its $105 million debenture issue in July 2007.

Proceeds from long-term debt, net of issue costs, for 2007 compared to 2006 are summarized as follows:

Years Ended December 31st *($ millions)*	**2007**	2006	Variance
Borrowings under committed credit facilities:			
FortisAlberta	**105**	136	(31)
FortisBC	**19**	21	(2)
Newfoundland Power	**62**	19	43
Corporate	**417**	136	281
	603	312	291
Long-term debt issuances, net of costs:			
TGI	**250** (1)	–	250
FortisAlberta	**110** (2)	100 (3)	10
FortisBC	**104** (4)	–	104
Newfoundland Power	**70** (5)	–	70
Caribbean Utilities	**48** (6) (7)	–	48
Corporate	**209** (8)	45 (9)	164
Other	**6**	12	(6)
	797	157	640
Total	**1,400**	469	931

(1) Issued October 2007, 6.00% Unsecured Medium-Term Note Debentures, due October 2037
(2) Issued January 2007, 4.99% Senior Unsecured Debentures, due January 2047
(3) Issued April 2006, 5.40% Senior Unsecured Debentures, due April 2036
(4) Issued July 2007, 5.90% Senior Unsecured Debentures, due July 2047
(5) Issued August 2007, 5.901% First Mortgage Sinking Fund Bonds, due August 2037
(6) Issued November 2007, US$10 million 5.65% Senior Unsecured Notes, due June 2022
(7) Issued June 2007, US$30 million 5.65% Senior Unsecured Notes, due June 2022
(8) Issued September 2007, US$200 million 6.60% Senior Unsecured Notes, due September 2037
(9) Issued November 2006, US$40 million 5.50% Unsecured Subordinated Convertible Debentures, due November 2016

Borrowings under committed credit facilities by FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 were primarily in support of their respective capital expenditure programs.

Borrowings by the Corporation under its committed credit facility in 2007 were used primarily to fund, on an interim basis, the remaining cash purchase price of Terasen, including certain acquisition costs; to fund Common Share issuance costs; to repay certain debt assumed upon the acquisition of Terasen; to finance a significant portion of the cash purchase price of the Delta Regina in August 2007; and in support of general corporate activities. Borrowings by the Corporation under its committed credit facilities in 2006 were used primarily to finance, in part, the acquisition by Fortis Properties of four hotels in Alberta and British Columbia in November 2006; to finance, in part, the acquisition of the additional 16 per cent ownership interest in Caribbean Utilities in November 2006; to fund the August 2006 acquisition of Fortis Turks and Caicos; to fund an equity requirement of one of the Corporation's western electric utilities; and for general corporate activities.

Net proceeds from the Corporation's US$200 million unsecured notes issued in September 2007 were used to repay existing indebtedness previously borrowed under the Corporation's committed credit facility associated with the Terasen acquisition and for general corporate purposes. Net proceeds from the Corporation's US$40 million unsecured convertible debentures in 2006 were

used to fund, in part, the acquisition of the additional approximate 16 per cent ownership interest in Caribbean Utilities. Most of the net proceeds from long-term debt issuances at FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 were used to repay indebtedness previously borrowed under respective committed credit facilities and for general corporate purposes. Net proceeds from Caribbean Utilities' US$40 million unsecured notes in 2007 were used to repay debt and to finance capital expenditures. The proceeds from the issuance of $250 million unsecured debentures at TGI in October 2007 were used to refinance $250 million of existing debt that matured in October 2007.

Repayments of long-term debt and capital lease obligations for 2007 compared to 2006 are summarized as follows:

Years Ended December 31st *($ millions)*	**2007**	2006	Variance
Repayment of committed credit-facility borrowings:			
FortisAlberta	**181**	97	84
FortisBC	**40**	–	40
Newfoundland Power	**64**	–	64
Corporate	**293**	72	221
	578	169	409
Repayment of long-term debt and capital lease obligations:			
TGI	**250**	–	250
Newfoundland Power	**36**	–	36
BECOL	**28**	–	28
Other	**49**	28	21
	363	28	335
Total	**941**	197	744

The repayment of committed credit-facility borrowings by FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 was financed with partial proceeds from various long-term debt issuances, in addition to proceeds from the sale of FortisAlberta's 2006 AESO Charges Deferral Account. During 2007, the net repayment of committed credit-facility borrowings by the Corporation was financed with partial proceeds from a 5.17 million Common Share issue in January 2007 and the US$200 million unsecured notes issued in September 2007. During 2006, the net repayment of committed credit-facility borrowings by the Corporation was financed with partial proceeds from a $125 million ($121 million net of costs) preference share offering in September 2006. The repayment of maturing long-term debt by TGI in October 2007 was financed with proceeds from the issuance of the $250 million 6.00% unsecured debentures. The repayment of maturing long-term debt by Newfoundland Power in 2007 was financed with partial proceeds from the Company's $70 million 5.901% first mortgage sinking fund bonds issued in August 2007. In November 2007, the term loan at BECOL was repaid in full.

Net proceeds associated with the issuance of Common Shares under the Corporation's share purchase and stock option plans in 2007 were $23 million compared to $15 million last year. Additionally, on May 17, 2007, the Corporation publicly issued 44.3 million Common Shares for gross proceeds of approximately $1.15 billion ($1.1 billion net of costs) upon conversion of Subscription Receipts that were initially issued in March 2007, to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million Common Shares were publicly issued for gross proceeds of approximately $150 million ($143 million net of costs). A significant portion of the net proceeds from the Common Share issue in January 2007 was used to repay approximately $84 million of existing indebtedness incurred under the Corporation's committed credit facilities. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

Common share dividends were $128 million for 2007, up $55 million from last year. The increase was due to an increase in the number of Common Shares outstanding, primarily due to the issuance of Common Shares pursuant to the Terasen acquisition and the issuance of 5.17 million Common Shares in January 2007, and a higher dividend per common share compared to 2006.

The $4 million increase in preference share dividends year over year related to the preference shares that were issued in September 2006.

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2007, are outlined in the following table.

($ millions)	**Total**	≤ 1 year	>1–3 years	4–5 years	> 5 years
Long-term debt (1)	**5,057**	433	412	623	3,589
Brilliant Terminal Station ("BTS") (2)	**66**	3	5	5	53
Gas purchase contract obligations (3)	**537**	515	22	–	–
Power purchase obligations					
FortisBC (4)	**2,856**	40	74	76	2,666
FortisOntario (5)	**286**	21	43	45	177
Maritime Electric (6)	**7**	7	–	–	–
Belize Electricity (7)	**15**	2	2	2	9
Capital cost (8)	**402**	14	34	39	315
Joint-use asset and shared service agreements (9)	**66**	4	8	6	48
Office lease – FortisBC (10)	**20**	1	2	2	15
Operating lease obligations (11)	**176**	20	33	30	93
Other	**25**	6	10	9	–
Total	**9,513**	1,066	645	837	6,965

(1) In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2007 and TGVI is expected to make an approximate $6 million repayment on the loans in 2008. As at December 31, 2007, the outstanding balance of the repayable government loans was $67 million with approximately $6 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's revenue deficiency deferral account and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

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

(3) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2007.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(5) Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires on December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing which expires on June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at $0.14 million per month.

(6) Maritime Electric has one take-or-pay contract with New Brunswick Power ("NB Power") for the purchase of either capacity or energy. This contract totals approximately $7 million through March 31, 2008.

(7) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited, which commenced in February 2007, for the supply of 3 MW of capacity and a two-year power purchase agreement between Belize Electricity and Comisión Federal de Electricidad of Mexico, expiring in August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen"), which is scheduled to commence in mid-2009, that provides for the supply of approximately 14 MW of capacity. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.

(8) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2012 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

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

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

Capital Resources

The Corporation's principal business of regulated gas and electric distribution utilities requires ongoing access to capital to allow it to fund the maintenance and expansion of infrastructure. To help ensure access to capital, the Corporation targets a long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt and investment-grade credit ratings. The capital structure of Fortis is presented in the following table.

	December 31, 2007		December 31, 2006	
	($ millions)	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) (1)	**5,476**	**64.3**	2,700	61.1
Preference shares (2)	**442**	**5.2**	442	10.0
Common shareholders' equity	**2,601**	**30.5**	1,276	28.9
Total	**8,519**	**100.0**	4,418	100.0

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

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

The change in the capital structure in 2007 was driven by the issuance of 5.17 million Common Shares in January 2007, for net after-tax proceeds of approximately $146 million; the issuance of 44.3 million Common Shares in May 2007, for net after-tax proceeds of $1.12 billion; the $2.4 billion of consolidated debt assumed upon the acquisition of Terasen; additional debt incurred to partially finance the net cash purchase price of Terasen; and debt incurred at the subsidiaries in support of their capital expenditure programs. The capital structure was also impacted by net earnings applicable to common shares, less common share dividends, of $65 million during 2007 and an increase in accumulated other comprehensive loss of $37 million during 2007.

Effective June 19, 2007, S&P raised the long-term corporate credit rating of Fortis to 'A–' from 'BBB+' and the unsecured debt credit rating of Fortis to 'A–' from 'BBB'. The credit rating upgrades reflect the improved diversity of Fortis resulting from the acquisition of Terasen; the stand-alone operations and the financial separation of each of the regulated subsidiaries of Fortis; management's commitment to maintaining low levels of debt at the holding company level; the continued focus of Fortis on pursuing acquisitions of stable regulated utilities; and the success of FortisAlberta and FortisBC in executing their large capital expenditure programs.

The Corporation's credit ratings are as follows:

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

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2007, approximately $87 million in maintenance and repairs was expensed compared to approximately $59 million during 2006. The increase year over year was driven by the inclusion of the Terasen Gas companies in the Corporation's financial results from May 17, 2007, the date of acquisition; the impact of the consolidation of Caribbean Utilities' financial results during 2007; and the first full year of ownership of Fortis Turks and Caicos.

During 2007, actual gross consolidated utility capital expenditures of Fortis were $790 million, which exceeded the estimate of $610 million, as disclosed at December 31, 2006, by $180 million. The increase was driven by the Terasen Gas companies and FortisAlberta. The Terasen Gas companies spent approximately $120 million from the date of acquisition. The increase in capital spending at FortisAlberta was driven by load growth and inflation and was included in FortisAlberta's 2008/2009 revenue requirements application.

A summary of gross utility capital expenditures for 2007 by segment and asset category is provided in the following table.

Gross Utility Capital Expenditures

Year Ended December 31, 2007

($ millions)	Terasen Gas Companies(1)	Fortis Alberta(1)(2)	Fortis BC(1)	Newfoundland Power(1)	Other Regulated Utilities – Canadian(1)	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated**	**Total(3)**
Generation	–	–	21	20	3	**44**	**33**	**17**	**94**
Transmission	50	–	67	5	5	**127**	**9**	**–**	**136**
Distribution	62	202	38	39	27	**368**	**43**	**1**	**412**
Facilities, equipment, vehicles and other	5	63	14	4	2	**88**	**19**	**4**	**111**
Information technology	3	20	7	4	1	**35**	**2**	**–**	**37**
Total	**120**	**285**	**147**	**72**	**38**	**662**	**106**	**22**	**790**

(1) Gross utility capital expenditures include removal and site restoration expenditures which are permissible in rate base.

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

(3) Includes expenditures associated with assets under construction

Gross consolidated utility capital expenditures for 2008 are expected to be approximately $890 million. Planned capital expenditures are based on detailed forecasts of customer demand, weather, and cost of labour and materials, as well as other factors which could change and cause actual expenditures to differ from forecasts.

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

Forecast Gross Utility Capital Expenditures

Year Ending December 31, 2008

($ millions)	Terasen Gas Companies[1]	Fortis Alberta[2]	Fortis BC[1]	Newfoundland Power[1]	Other Regulated Utilities – Canadian[1]	**Total Regulated Utilities – Canadian**	**Regulated Utilities – Caribbean**	**Non-Regulated**	**Total[3]**
Generation	–	–	17	4	3	**24**	**25**	**32**	**81**
Transmission	107	–	75	6	6	**194**	**13**	**–**	**207**
Distribution	125	196	31	36	24	**412**	**55**	**1**	**468**
Facilities, equipment, vehicles and other	5	51	8	3	2	**69**	**7**	**15**	**91**
Information technology	13	17	5	4	3	**42**	**1**	**–**	**43**
Total	**250**	**264**	**136**	**53**	**38**	**741**	**101**	**48**	**890**

(1) Gross utility capital expenditures include removal and site restoration expenditures which are permissible in rate base.
(2) Excludes forecast payments of $22 million to be made to the AESO for investment in transmission facilities
(3) Includes expenditures associated with assets under construction

The percentage breakdown of 2007-actual and 2008-forecast gross utility capital expenditures among growth, sustaining and other is as follows:

Year Ended December 31st

(%)	**Actual 2007**	Forecast 2008
Growth	**46**	50
Sustaining[1]	**35**	35
Other[2]	**19**	15
Total	**100**	100

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

Significant utility capital expenditure projects are summarized in the table below.

($ millions) Utility	Nature of project	Actual 2007	Forecast 2008	Costs to complete after 2008	Expected year to complete
Terasen Gas Companies	LNG storage facility – Vancouver Island	**–**	50	125–150	2011
	Squamish-to-Whistler pipeline	**16** (1)	11	1	2008/2009
	Texada Island Compressor Station	**10** (1)	–	–	2007
	Replacement of the Vancouver low-pressure system	**5** (1)	6	–	2008
FortisAlberta	New operations facility in Airdrie	**21**	8	–	2008
	Automated Meter Infrastructure ("AMI") technology	**7**	24	80	2010
FortisBC	New/upgraded substations and associated transmission lines	**49**	13	–	2008
	Generation asset Upgrade and Life-Extension Program	**20**	16	46	2011
Newfoundland Power	Rattling Brook hydroelectric generating plant refurbishment	**17**	–	–	2007
Caribbean Utilities	New 16-MW diesel-fired generating unit	**20**	–	–	2007
Non-Regulated – Fortis Generation	18-MW Vaca hydroelectric generating facility in Belize	**14**	30	13	2009

(1) Capital expenditures are from May 17, 2007, the date of acquisition

During 2008, TGVI is expected to spend $50 million on the construction of a new 1.5 billion-cubic foot LNG storage facility on Vancouver Island to meet current and future gas demands. The facility is expected to be completed by 2011 for a total cost of approximately $175 million to $200 million. It will allow more efficient use of TGI's existing pipeline systems and result in improved reliability and security of supply during planned or unplanned system interruptions or in times of high demand. In November 2007, TGVI received conditional BCUC approval for the construction of the facility. Construction is expected to begin in April 2008 with the facility coming into service by late 2011. During 2007, approximately $16 million was spent on the extension of TGI's pipeline system to Whistler through the construction of a 50-kilometre pipeline lateral from Squamish to Whistler. The extension is required in conjunction with the conversion of TGWI's piped propane system to natural gas. The total capital cost of the project is estimated at approximately $40 million, including amounts incurred prior to 2007 and amounts recorded in regulatory deferral accounts associated with the pipeline conversion.

Approximately 405,000 customer sites at FortisAlberta will have their conventional meters replaced by new AMI technology. AMI technology will allow for remote collection of meter data and result in more accurate reporting of customer consumption to retailers, based on actual rather than estimated usage. This technology change will improve billing accuracy, increase customer satisfaction, reduce customer inquiries and significantly reduce the operating cost of the current manual meter-reading practice. In 2008, FortisAlberta is expected to spend $24 million on AMI technology, which is expected to be fully implemented by 2010 at an estimated capital cost of approximately $111 million over the four-year period.

During 2007, work commenced at FortisBC on a number of new substations, substation upgrades and associated transmission lines. Total capital expenditures associated with these projects was $49 million in 2007, with $13 million expected to be incurred in 2008.

Since 1998, FortisBC's hydroelectric generating facilities have been subject to an Upgrade and Life-Extension Program which is forecast to conclude in 2011. Approximately $20 million was spent on this Program in 2007, with an additional $62 million expected to be incurred from 2008 through 2011.

In May 2007, BECOL received all major approvals for the construction of an estimated $57 million (US$53 million) 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize. In 2008, BECOL is expected to spend $30 million (US$28 million) on the construction of this generating facility. Belize Electricity has signed a 50-year power purchase agreement with BECOL for the purchase of energy to be generated by the Vaca facility, which is expected to commence operations late in 2009. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generating facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Assuming normal hydrology, the facility is expected to be immediately accretive to earnings per common share of Fortis when it comes into service late in 2009.

During 2007, capital expenditures associated with income producing properties totalled approximately $13 million. In addition, Fortis Properties purchased the Delta Regina for approximately $50 million. Fortis Properties expects to spend approximately $11 million in capital projects in 2008.

Fortis expects gross electric utility capital expenditures of more than $3 billion over the next five years will be driven by FortisAlberta, FortisBC, and the Corporation's regulated and non-regulated electric utility operations in the Caribbean. Fortis expects gross gas utility capital expenditures over the next five years to exceed $1 billion.

The cash required to complete the planned capital programs is expected to be derived from a combination of long-term and short-term borrowings, internally generated funds and the issuance of common shares and preference shares. Fortis does not anticipate any difficulties accessing the required capital on reasonable market terms.

Cash Flows: The Corporation's ability to service debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis.

As at December 31, 2007, the Corporation and its subsidiaries had consolidated authorized lines of credit of $2.2 billion, of which $1.1 billion was unused. The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2007**	Total as at December 31, 2006
Total credit facilities	715	1,506	13	**2,234**	952
Credit facilities utilized					
Short-term borrowings	(6)	(468)	(1)	**(475)**	(98)
Long-term debt	(208)	(322)	–	**(530)**	(235)
Letters of credit outstanding	(55)	(103)	(1)	**(159)**	(72)
Credit facilities available	446	613	11	**1,070**	547

At December 31, 2007 and December 31, 2006, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in total credit facilities from December 31, 2006 to December 31, 2007 are described as follows.

Corporate and Other

At December 31, 2007, Terasen Inc. had a $100 million unsecured committed revolving credit facility, maturing in May 2009. This credit facility was reduced from $180 million in July 2007 and is available for general corporate purposes. Letters of credit outstanding of $55 million at Terasen Inc., related to its previously owned petroleum transportation business, are secured by a letter of credit from the former parent company.

On May 14, 2007, Fortis cancelled its $50 million unsecured revolving committed credit facility and renegotiated and amended its $250 million unsecured committed credit facility, extending the maturity date to May 2012 and increasing the amount available to $500 million with the ability, at the Corporation's option, to increase the credit facility to an aggregate of $600 million. During the fourth quarter of 2007, the Corporation increased the amount of its credit facility to $600 million in accordance with the terms thereof.

Regulated Utilities

At December 31, 2007, TGI had a $500 million unsecured committed revolving credit facility. In August 2007, the facility was renegotiated and extended with similar terms and matures in August 2012. At December 31, 2007, TGVI had a $350 million unsecured committed revolving credit facility, maturing in January 2011. These facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also had a $20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing any annual repayments on non-interest bearing government loans.

In May 2007, FortisAlberta terminated one of its $10 million unsecured demand credit facilities and extended the maturity date of its $200 million unsecured committed credit facility to May 2012 from May 2010.

In May 2007, FortisBC renegotiated and amended its $150 million unsecured committed revolving credit facility, reallocating the amounts available between the 364-day portion of the facility and the three-year portion of the facility, and extending the maturity date of the three-year facility to May 2010 from May 2008. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval.

On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit from US$13 million to US$19 million, including amounts available for letters of credit, and increasing each of its US$5 million operating line of credit and US$5 million catastrophe standby loan to US$7.5 million.

Off-Balance Sheet Arrangements

As at December 31, 2007, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

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

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation which can impact future revenues and earnings. Management at each operating 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 90 per cent of the Corporation's operating revenue and equity income was derived from regulated utility operations in 2007 (2006 – 84 per cent), while approximately 81 per cent of the Corporation's operating earnings were derived from regulated utility operations in 2007 (2006 – 75 per cent). These regulated operations, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. These uncertainties include approvals by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. The ability of the utilities to recover the actual costs of providing services and to 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.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters which may, in turn, negatively affect the Corporation's results of operations or financial position.

Although Fortis considers the regulatory frameworks in each of the jurisdictions to be fair and balanced, uncertainties do exist at the present time. Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions which govern the competitive wholesale and retail electricity markets are relatively new and there may be significant changes in these regulations and

market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return formulas, are also being employed to varying degrees.

TGI, TGVI and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGVI have been extended through 2009. The PBR mechanism at FortisBC runs through 2008, with an option to extend the term through 2009. 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 the particular terms of any such PBR mechanisms.

Integration of Terasen and Management of Expanding Operations: Fortis continues to integrate Terasen within the Fortis Group. As a result of the acquisition, significant demands may be placed on the managerial, operational and financial personnel and systems of the Corporation. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the acquisition. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Operating and Maintenance Risks: Terasen is 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 environmental liability. The business of electricity 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. The facilities of the operating subsidiaries are also exposed to the effects of severe weather conditions and other acts of nature. In addition, many of these facilities are 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 operating subsidiaries have insurance which 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.

The Corporation's gas and electricity systems require maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the operating subsidiaries 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 capital expenditures which the operating subsidiaries believe are necessary to maintain, improve and replace their assets; the failure by the operating subsidiaries to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures despite maintenance programs could have a material adverse effect on the Corporation.

Natural Gas Prices: At times in the past, 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, 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 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. The Terasen Gas 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. 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 therefore serves to mitigate the effect on earnings of natural gas cost volatility. Future BCUC determinations could materially impact the ability of the Terasen Gas companies to recover the future cost of natural gas delivered to customers.

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. As a result, 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. In addition, the Terasen Gas companies are 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 revenues and incurring costs to safely relight customers.

Economic Conditions: Typical of utilities, the general economic conditions of the Corporation's service territories influence energy sales. Gas and electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. A general and extended decline in the economy in the Corporation's service territories would be expected to have the effect of reducing demand for gas and electricity over time. Such reduced demand could negatively impact revenue. However, the regulated nature of utility operations helps to reduce the impact that economic downturns may have on the Corporation's earnings. A prolonged downturn in the economy in the Corporation's service territories could adversely affect the business, results of operations and financial condition of the Corporation, despite the possibility of regulatory-approved means of compensating for reduced demand.

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. The high quality of the real estate and hotel assets and commitment to productivity improvements reduce the exposure to industry fluctuations. Fortis Properties' real estate investments are anchored by high-quality tenants with long-term leases. Exposure to lease expiries averages approximately 10 per cent per annum over the next five years. Approximately 58 per cent of Fortis Properties' operating income was derived from hotel investments in 2007 (2006 – 52 per cent). Management believes that, based on the geographic diversity of its Hospitality Division with locations in Atlantic Canada, Ontario, Manitoba, Saskatchewan, Alberta and British Columbia, the Company is not exposed to a significant reduction in revenues. A 5 per cent decrease in revenues from the Hospitality Division would decrease basic earnings per common share of Fortis by approximately 1 cent.

Weather and Seasonality: The physical assets of the Corporation and its operating 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 by the operation of a weather normalization reserve, a regulatory mechanism approved by the PUB. 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 by the Terasen Gas companies is ultimately used for space heating. 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 earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Despite preparation for severe weather, extraordinary conditions (such as Hurricane Ivan in September 2004) and other natural disasters will always remain a risk to utilities. Upon acquiring controlling interest in Caribbean Utilities and upon the acquisition of Fortis Turks and Caicos, the Corporation's exposure to risks from natural disasters in the Caribbean region increased. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and to reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, the PUC provides for recovery of certain costs arising from hurricanes through a surcharge on electricity rates, thereby mitigating the financial impact to Belize Electricity.

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.

Interest Rates: 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 either directly impacted 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 an increase in long-term Canada bond yields during 2007 and the operation of the automatic adjustment mechanisms, the allowed ROE at each of the above utilities has been reset. The 2007 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.37 per cent, 8.51 per cent, 8.77 per cent and 8.60 per cent, respectively. Effective January 1, 2008, the allowed ROEs for TGI, FortisAlberta, FortisBC and Newfoundland Power have increased to 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. A significant decline in long-term interest rates could adversely affect the Corporation's ability to earn a reasonable ROE which, in turn, could have a material adverse effect on the Corporation's financial condition and results of operations.

The Corporation and its operating subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. As described under the heading "Derivatives Instruments and Hedging", the Corporation and its operating subsidiaries may enter into interest rate swaps to help reduce this risk. Approximately 74 per cent of the Corporation's long-term debt facilities and capital lease obligations have maturities beyond five years. The following table outlines the nature of the Corporation's consolidated debt at December 31, 2007.

Total Debt

at December 31, 2007	*($ millions)*	*(%)*
Short-term borrowings	**475**	**8.6**
Utilized variable-rate credit facilities classified as long-term	**530**	**9.6**
Variable-rate long-term debt and capital lease obligations (including current portion)	**14**	**0.2**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**4,515**	**81.6**
Total	**5,534**	**100**

The Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Derivative Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates and natural gas prices through the use of derivative financial instruments. Derivative financial instruments, such as interest rate swap contracts and natural gas commodity swaps and options, are used only to manage risk and are not used for trading purposes. All derivative financial instruments must be measured at fair value, with changes in fair value being recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At rate-regulated utilities, 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 its foreign investments are exposed to changes in the US dollar to Canadian dollar exchange rate. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with earnings from its foreign net investments through the use of US dollar borrowings.

It is expected that a 4-cent change in the value of the US dollar would have an approximate 1-cent impact on basic earnings per common share of Fortis in 2008.

Fortis has also designated its corporate-held US dollar-denominated long-term debt as a hedge of the foreign currency exchange risk related to its net investments in US dollar-denominated self-sustaining foreign operations. This hedge allows unrealized gains and losses on the translation of the US dollar-denominated long-term debt to be offset against unrealized foreign currency exchange gains and losses on the foreign net investments. The unrealized foreign currency exchange gains and losses on US dollar-denominated long-term debt and foreign net investments are recognized in other comprehensive income. As at December 31, 2007, approximately US$50 million in foreign net investments remained available to be hedged.

Management will continue to hedge future exchange rate fluctuations related to its foreign net investments and US dollar earnings streams, where possible, through the use of future US dollar borrowings and will monitor the exposure of Fortis to foreign currency fluctuations on a regular basis.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining $67 million non-interest bearing senior government debt, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As this 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.

Capital Resources: The Corporation's financial position could be adversely affected if it or its operating subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. 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 anticipated capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

Generally, the Corporation and its regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's finance charges.

Environment: The Corporation and its operating 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 and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Corporation. The process of obtaining environmental, health and safety regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. Environmental damage and other costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. However, there can be no assurance that such costs will be recoverable through customer rates at the regulated utilities and, if substantial, unrecovered costs may have a material adverse effect on the business, results of operations and financial condition of the Corporation.

Insurance: While the Corporation and its operating subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its operating 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 operating 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 business, results of operations and financial condition.

It is anticipated that such insurance coverages will be maintained. However, there can be no assurance that the Corporation and its operating 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.

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 have a material adverse effect on the Corporation.

Energy Prices and Cessation of the Niagara Exchange Agreement: The Corporation's primary exposure to changes in energy prices relates to its non-regulated energy sales in Ontario. Energy is sold to the Independent Electricity System Operator at market prices. The sensitivity of the Corporation's earnings to each $1 per MWh change in the annual average wholesale market price of electricity in Ontario is expected to be approximately $0.4 million. 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 Generating Station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will not be renewed, effective May 1, 2009. During 2007, earnings' contribution associated with the Niagara Exchange Agreement was approximately $15 million. This earnings' contribution will cease effective May 1, 2009. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to 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.

The regulated utilities of Fortis flow through gas, energy and fuel costs to customers in their respective gas and electricity rates.

Loss of Service Area: FortisAlberta serves a number of direct customers that reside within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently initiated 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 have a material adverse effect on the financial condition and results of operations of FortisAlberta.

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 adversely 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 be unable to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material adverse effect on the business of FortisAlberta.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. Because the Terasen Gas companies deal with high credit-quality institutions, in accordance with established credit-approval practices, the Terasen Gas companies do not expect any counterparties to fail to meet their obligations. 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.

Labour Relations: Approximately 59 per cent of the employees of the Corporation's operating subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the operating 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 to 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 adverse effect on the results of operations, cash flow and earnings of the Corporation.

The organized employees of TGI are represented by the Canadian Office and Professional Employees Union, Local 378, which ratified a new five-year collective agreement with TGI expiring in March 2012, ending limited job action that began on September 23, 2007, and by the International Brotherhood of Electrical Workers ("IBEW"), Local 213, under a collective agreement expiring on March 31, 2011.

On December 31, 2007, the collective agreement between FortisAlberta and the United Utility Workers Association ("UUWA"), Local 200, was due to expire. On December 13, 2007, FortisAlberta reached a tentative three-year collective agreement with UUWA, Local 200, which was ratified by the membership in February 2008.

On November 30, 2007, the collective agreement between Fortis Properties and the Communications, Energy and Paperworkers Union, Local 651, representing employees at the Delta Regina, expired. Negotiations with the union commenced in January 2008.

On January 31, 2008, the collective agreement between FortisBC and IBEW, Local 213, was due to expire. FortisBC and IBEW, Local 213, reached a Memorandum of Agreement which was ratified in December 2007, extending the collective agreement for one year to January 31, 2009.

In September 2008, two collective agreements governing Newfoundland Power's unionized employees represented by IBEW, Local 1620, are due to expire. In December 2008, the collective agreement governing Maritime Electric's unionized employees represented by IBEW, Local 1432, is also due to expire.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of its operating subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, Fortis 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. In particular, Alberta has a highly competitive job market where the demand for certain job skills exceeds the supply, making it difficult to attract new employees.

Liquidity Risk: Earnings from Belize Electricity are denominated in Belizean dollars, earnings from Caribbean Utilities are denominated in Cayman Island dollars and earnings from FortisUS Energy, BECOL and Fortis Turks and Caicos are denominated in US dollars. As at December 31, 2007, the Cayman Island dollar and the Belizean dollar were pegged to the US dollar at CI$0.84 = US$1.00 and BZ$2.00 = US$1.00, respectively. Foreign earnings derived in currencies other than the US dollar must be converted into US dollars before repatriation, presenting temporary liquidity risks. Due to the small size and cyclical nature of the economy in Belize, conversion of local currency into US dollars may be subject to restrictions from time to time.

Changes in Accounting Standards

The nature of and impact on Fortis of adopting the new Canadian Institute of Chartered Accountants ("CICA") accounting standards for Financial Instruments, Hedges and Comprehensive Income, effective January 1, 2007, is described in detail in Notes 2, 16 and 24 to the 2007 Fortis Inc. Annual Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the reallocation of $21 million of deferred financing costs from deferred charges and other assets to long-term debt; (ii) the reporting of a Statement of Comprehensive Income; (iii) the recording, in other comprehensive loss, of unrecognized foreign currency translation gains and losses on US dollar-denominated debt that is hedging the Corporation's net investments in self-sustaining foreign operations; (iv) the reallocation of $51 million of unrealized foreign currency translation losses on net investments in self-sustaining foreign operations from the foreign currency translation adjustment account in shareholders' equity to accumulated other comprehensive loss; (v) the reallocation of an $11 million ($7 million after-tax) unamortized loss balance relating to a previously cancelled interest rate swap agreement from deferred charges and other assets, and the reallocation of a $3 million ($2 million after-tax) unamortized gain balance relating to a previously cancelled US dollar forward currency swap agreement from deferred credits, to accumulated other comprehensive loss; and (vi) the recording of opening fair value and subsequent changes in fair value of the Corporation's interest rate swap contracts in effective hedging relationships in accumulated other comprehensive loss and other comprehensive loss, respectively. The adoption of the accounting standards did not have a material impact on the Corporation's 2007 consolidated statement of earnings.

Also as disclosed in Note 2 to the 2007 Fortis Inc. Annual Consolidated Financial Statements, Fortis adopted the revised standard for accounting changes, effective January 1, 2007. This new standard had no impact on the Corporation's consolidated financial statements for the year ended December 31, 2007, except for the disclosures provided in Note 3 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS"): In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period. In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-oriented enterprises. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010. While Fortis has begun assessing the adoption of IFRS for 2011, the financial reporting impact on the Corporation of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations: In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation* ("AcG-19"), be retained as is.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets as well as offsetting regulatory assets and liabilities at entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. The AcSB also decided that the current guidance for rate-regulated operations pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained, and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate-regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as "another source of GAAP" within the Canadian GAAP hierarchy.

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the taxes-payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2007, would have been an increase in future tax assets and future tax liabilities of $54 million and $489 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $54 million and $489 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates, and the separate disclosure of future income tax assets and liabilities that are currently not recognized. Fortis is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Inventories: In March 2007, the AcSB approved the new Section 3031, *Inventories*, effective for fiscal years beginning on or after January 1, 2008. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in, first-out inventory-costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Corporation's earnings, cash flow or financial position.

Capital Disclosures: As a result of new Section 1535, *Capital Disclosures*, Fortis will be required to include additional information in the Notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. This Section is applicable to Fortis for the fiscal year beginning on January 1, 2008.

Disclosure and Presentation of Financial Instruments: New accounting recommendations for disclosure and presentation of financial instruments, Sections 3862 and 3863, are effective for the Corporation beginning on January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets of Fortis approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments. The fair value of long-term debt is calculated by discounting the future cash flow of each debt instrument at the estimated yield to maturity for the same or similar issues at the balance sheet date, or by using available quoted market prices. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

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

	2007 (1)		2006	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	**5,023**	**5,635**	2,614	2,940
Preference shares, classified as debt (2)	**320**	**346**	320	355

(1) Includes long-term debt of Terasen from May 17, 2007, the date of acquisition

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $122 million of preference shares classified as equity was $107 million at December 31, 2007 (December 31, 2006 – $129 million).

The Corporation hedges exposures to fluctuations in interest rates and natural gas commodity prices through the use of derivative financial instruments. The following table indicates the valuation of derivative financial instruments as at December 31st.

	2007[1]				2006	
Liability	**Term to Maturity** *(years)*	**Number of Swaps**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest Rate Swaps	**1 to 3**	**4**	**–**	**–**	–	(1)
Natural Gas Commodity Swaps and Options	**Up to 3**	**244**	**(79)**	**(79)**	–	–

[1] Includes derivative financial instruments of the Terasen Gas companies from May 17, 2007, the date of acquisition

Two of the four interest rate swaps are held by Fortis Properties and are designated as hedges of the cash flow risk related to floating-rate long-term debt. The effective portion of changes in the value of the interest rate swaps at Fortis Properties is recorded in other comprehensive income. The remaining interest rate swaps and all of the natural gas commodity swaps and options are held by the Terasen Gas companies. The interest rate swaps are designated as hedges of cash flow risk related to floating-rate debt instruments. The natural gas commodity swaps and options are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. At the Terasen Gas companies, changes in the fair value of the interest rate swaps and the natural gas commodity swaps and options are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the swaps and options were recorded in accounts payable as at December 31, 2007.

The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves. The fair values of the natural gas commodity swaps and options reflect the estimated amount that the Corporation would have to pay if forced to settle all outstanding contracts at year end.

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

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2007, Fortis recorded $312 million in current and long-term regulatory assets (December 31, 2006 – $171 million) and $392 million in current and long-term regulatory liabilities (December 31, 2006 – $359 million). The increase in regulatory assets year over year was largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2007, the Corporation's consolidated utility and income producing properties were $7.2 billion, or approximately 70 per cent of total consolidated assets, compared to consolidated utility and income producing properties of $4.0 billion, or approximately 74 per cent of total consolidated assets, as at December 31, 2006. The increase in capital assets was primarily associated with the Terasen Gas companies. Amortization expense for 2007 was $273 million compared to $178 million for 2006. Changes in amortization rates can have a significant impact on the Corporation's amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount to provide for future removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2007 was $319 million (December 31, 2006 – $307 million). The amount of future removal and site restoration costs provided for and reported in amortization expense during 2007 was $33 million (2006 – $30 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization as a result of actual experience differing from that expected and provided for in previous amortization rates is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2007, GEC totalled $40 million (2006 – $18 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a significant impact on the amount recorded as operating expenses and utility capital assets.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill, which is based on current information and fair market value assessments of the reporting units being reviewed. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $1.54 billion in goodwill recorded on the Corporation's balance sheet as at December 31, 2007. The net increase in goodwill during 2007 was due to the acquisition of Terasen.

Employee Future Benefits: The Corporation's defined benefit pension plans and OPEB plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations were the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets. Other assumptions applied were average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions were also utilized by management in determining OPEB plan expense and obligations. Assumptions were also made regarding the health-care cost trend increase. FortisAlberta and Newfoundland Power record the cost of pension and/or OPEB plan expense on a cash basis. Therefore, changes in assumptions do not impact earnings

of those subsidiaries. As at December 31, 2007, the Corporation had a consolidated accrued benefit asset of $120 million (December 31, 2006 – $93 million) and a consolidated accrued benefit liability of $150 million (December 31, 2006 – $63 million). During 2007, the Corporation recorded consolidated net benefit expense of $26 million (2006 – $20 million).

The following table reflects the sensitivities associated with a 0.5 per cent increase and a 0.5 per cent decrease in the expected long-term rate of return on plan assets and discount rate on 2007 net benefit expense and the accrued benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the benefit obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2007

	Net benefit expense		**Accrued benefit asset**		**Accrued benefit liability**		**Benefit obligation**	
($ millions)	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**	**Regulated Gas Utilities**	**Regulated Electric Utilities**
Impact of increasing the rate of return assumption by 0.5 per cent	(1)	(2)	1	2	–	–	–	–
Impact of decreasing the rate of return assumption by 0.5 per cent	1	2	(1)	(2)	–	–	–	–
Impact of increasing the discount rate assumption by 0.5 per cent	(2)	(3)	–	2	(1)	(1)	(27)	(32)
Impact of decreasing the discount rate assumption by 0.5 per cent	3	3	(2)	(2)	1	1	23	35

Asset-Retirement Obligations ("AROs"): In measuring the fair value of AROs, the Corporation is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the systems and the remediation of certain leased land, there were no amounts recorded as at December 31, 2007 and 2006. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation facilities are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers; and the land-lease agreement at Maritime Electric is expected to be renewed indefinitely. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Prior to January 1, 2006, Newfoundland Power also recognized electricity revenue on a billed basis. Effective January 1, 2006, Newfoundland Power adopted, on a prospective basis, the accrual method for recognizing revenue as approved by the PUB. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the gas and electricity sales estimates requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2007, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $309 million (December 31, 2006 – $132 million) on annual consolidated operating revenues of $2.72 billion (2006 – $1.46 billion).

Contingencies: Fortis is subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial position or results of operations.

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

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister has 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. On June 22, 2007, TGI filed an appeal of the assessment with the B.C. Supreme Court.

A non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

FortisAlberta

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately $3 million in firefighting and suppression costs and approximately $2 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date lead management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, FortisAlberta has not made any definitive assessment of potential liability, and the outcome with regard to the Company's liability for the claims made by the Crown is indeterminable. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

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

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the energy cost adjustment mechanism amounts 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 the $450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. 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, 2007, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the "Village"), New York. The Village 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 $7 million (US$7 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A Memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. An appeal of the summary judgment dismissal of the claim filed by the Village in January 2007 was heard by the Appellate Division, Fourth Judicial Department of the Supreme Court of the State of New York in December 2007. The Appellate Division delivered its Memorandum and Order on February 1, 2008 modifying the initial decision by dismissing the Village's appeal regarding its main claim, but reinstating a secondary cause of action dismissed by the summary judgment order. Further appeals to the New York State Court of Appeal may be forthcoming. Management believes that potential further legal actions by the Village will not be successful and, therefore, no provision has been made in the consolidated financial statements.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2007, 2006 and 2005. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Years Ended December 31st *($ millions, except per share amounts)*	**2007** (1)	2006	2005
Revenue and equity income	**2,718**	1,472	1,441
Net earnings	**199**	149	137
Net earnings applicable to common shares	**193**	147	137
Total assets	**10,273**	5,441	4,597
Long-term debt and capital lease obligations (net of current portion)	**4,623**	2,558	2,136
Preference shares (2)	**442**	442	320
Common shareholders' equity	**2,601**	1,276	1,213
Basic earnings per common share	**1.40**	1.42	1.35
Diluted earnings per common share	**1.32**	1.37	1.24
Dividends declared per common share	**0.88**	0.70	0.61
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series D	**–**	–	0.03 (3)
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F (4)	**1.2250**	0.5211	–

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

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

(3) The First Preference Shares, Series D were redeemed in September 2005.

(4) 5,000,000 First Preference Shares, Series F were issued on September 28, 2006 at $25.00 per share for net after-tax proceeds of $122 million and are entitled to receive cumulative dividends in the amount of $1.2250 per share per annum.

2007/2006 – Revenue, including equity income, increased 84.6 per cent over 2006. The increase was driven by contributions from the Terasen Gas companies, from the date of acquisition, and the impact of consolidating the Corporation's approximate 54 per cent controlling ownership in Caribbean Utilities during 2007 compared to recording the Corporation's 37 per cent interest in Caribbean Utilities during 2006 on an equity basis. Net earnings applicable to common shares grew 31.3 per cent over 2006, attributable to the acquisition of Terasen in May 2007, the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. The growth in total assets and increase in long-term debt in 2007 was driven by assets acquired and debt assumed upon the acquisition of Terasen in May 2007. The remaining increase in assets and long-term debt was primarily due to the Corporation's continued investment in electricity systems, driven by the capital expenditure programs at FortisAlberta and FortisBC and the acquisition of the Delta Regina, partially offset by the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. Common shareholders' equity more than doubled during 2007, driven by the issuance of approximately $1.15 billion in common equity required to fund a significant portion of the net cash purchase price of Terasen. Basic earnings per common share decreased 1.4 per cent from 2006. The seasonality of earnings of the Terasen Gas companies combined with the impact of the $1.15 billion common share issue diluted basic earnings per common share by 7 cents in 2007.

2006/2005 – Revenue, including equity income, increased 2.1 per cent over 2005. However, revenue at FortisAlberta in 2005 included approximately $20 million largely related to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments. The increase in revenue was largely driven by electricity sales growth at FortisAlberta and FortisBC, increased electricity rates at FortisBC and Belize Electricity and four months of revenue contribution from Fortis Turks and Caicos, partially offset by lower average wholesale energy prices in Ontario. Equity income from Caribbean Utilities was approximately $2 million lower than in 2005, but equity income during 2005 included a $1 million positive adjustment related to a change in Caribbean Utilities' accounting practice for recognizing unbilled revenue. Net earnings applicable to common shares in 2006 grew 7.3 per cent over 2005; however, earnings in 2005 included the $8 million after-tax Ontario Settlement gain. Growth in earnings in 2006 was primarily driven by strong electricity sales growth at FortisAlberta and FortisBC; lower corporate income taxes at FortisAlberta; improved non-regulated hydroelectric generation in Belize; earnings growth at Fortis Properties; the overall 11 per cent increase in electricity rates at Belize Electricity, effective July 1, 2005; and four months of earnings' contribution from Fortis Turks and Caicos. The increase was partially offset by lower average wholesale energy prices in Ontario and higher corporate costs. The growth in total assets and increase in long-term debt in 2006 was primarily associated with the extensive capital expenditure programs at FortisAlberta and FortisBC; the acquisition of an additional approximate 16 per cent ownership interest in Caribbean Utilities; the assumption of long-term debt upon consolidating the Corporation's resulting controlling ownership interest in Caribbean Utilities; and the acquisition of Fortis Turks and Caicos and four hotels in western Canada and the assumption of related long-term debt. The Corporation also issued $122 million in preference shares in 2006, the proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facilities incurred, in part, to fund the acquisition of Fortis Turks and Caicos, and to fund equity injections into FortisAlberta and FortisBC in support of their extensive capital expenditure programs.

The Corporation's dividend payout ratio was 58.6 per cent in 2007 compared to 47.2 per cent in 2006. On June 1, 2007, Fortis increased its quarterly common share dividend paid to 21 cents from 19 cents. Commencing with the first quarter dividend paid on March 1, 2008, Fortis increased its quarterly common share dividend 19 per cent to 25 cents per common share from 21 cents.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2006 through December 31, 2007. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue and Equity Income *($ millions)*	Net Earnings Applicable to Common Shares *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35
December 31, 2006	393	34	0.33	0.32
September 30, 2006	342	39	0.37	0.36
June 30, 2006	346	38	0.37	0.35
March 31, 2006	391	36	0.35	0.34

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. Financial results from May 17, 2007 were impacted by the acquisition of Terasen. Virtually all of the earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results from November 1, 2006 were impacted by the acquisition of four hotels in western Canada. Financial results from August 28, 2006 were impacted by the acquisition of Fortis Turks and Caicos, while earnings from January 1, 2007 were impacted by the consolidation of a controlling interest in Caribbean Utilities. The Corporation's interest in Caribbean Utilities was previously accounted for on an equity basis.

December 2007/December 2006 – Net earnings applicable to common shares were $79 million, or $0.51 per common share, for the fourth quarter of 2007, compared to earnings of $34 million, or $0.33 per common share, for the fourth quarter of 2006. The increase in earnings and earnings per common share was driven by contributions from the Terasen Gas companies, including a $7 million after-tax gain on the sale of surplus land, partially offset by increased corporate costs driven by Terasen acquisition-related finance charges.

September 2007/September 2006 – Net earnings applicable to common shares were $31 million, or $0.20 per common share, for the third quarter of 2007, compared to earnings of $39 million, or $0.37 per common share, for the third quarter of 2006. A $1.15 billion Common Share issue in May 2007 to fund a significant portion of the net cash purchase price of Terasen, combined with the seasonality of earnings of the Terasen Gas companies, diluted earnings per common share for the third quarter of 2007. Increased earnings' contribution from FortisAlberta, driven by customer growth and higher corporate income tax recoveries; increased earnings' contribution from Fortis Turks and Caicos, acquired in August 2006; and growth at Fortis Properties from expanded hospitality operations in western Canada were more than offset by higher finance charges associated with acquisitions, losses at the Terasen Gas companies due to seasonality of operations and lower non-regulated hydroelectric production due to lower rainfall.

June 2007/June 2006 – Net earnings applicable to common shares were $41 million, or $0.31 per common share, for the second quarter of 2007, compared to earnings of $38 million, or $0.37 per common share, for the second quarter of 2006. The $1.15 billion Common Share issue, combined with the seasonality of earnings of the Terasen Gas companies, diluted earnings per common share for the second quarter of 2007. The increase in overall earnings was driven by customer growth and increased energy deliveries at FortisAlberta; rate increases and electricity sales growth at FortisBC; and earnings' contribution from Fortis Turks and Caicos, acquired in August 2006, and the Terasen Gas companies, acquired in May 2007. The increase was partially offset by higher acquisition-related finance charges, the impact of decreased non-regulated hydroelectric production and lower earnings at Fortis Properties. However, earnings at Fortis Properties during the second quarter of 2006 were favourably impacted by $3 million associated with the sale of Days Inn Sydney and the reduction of future income tax liabilities.

March 2007/March 2006 – Net earnings applicable to common shares were $42 million, or $0.38 per common share, for the first quarter of 2007, up $6 million from earnings of $36 million, or $0.35 per common share, for the first quarter of 2006. Excluding the Corporation's $2 million share of a charge associated with the disposal of steam-turbine assets at Caribbean Utilities during the first quarter of 2007, earnings were $8 million higher than for the first quarter of 2006. The increase was primarily due to electricity sales growth and lower corporate income taxes at FortisAlberta, increased non-regulated hydroelectric production in Belize, earnings' contribution from Fortis Turks and Caicos, and electricity sales growth and lower finance charges at Belize Electricity.

The impact of increased earnings on earnings per common share was partially offset by the dilution created by the approximate $150 million issuance of 5.17 million Common Shares on January 18, 2007.

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO, together with management, have evaluated the effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2007 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for the design of internal controls over financial reporting within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design of the Corporation's internal controls over financial reporting as of December 31, 2007 and, based on that evaluation, have concluded that the design of the controls is effective to provide such reasonable assurance.

There has been no change in the Corporation's internal controls over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

Subsequent Event

On February 15, 2008, TGVI closed a $250 million 6.05% unsecured debenture offering, maturing on February 15, 2038. The net proceeds of the debenture offering were used to repay existing credit-facility borrowings.

Outlook

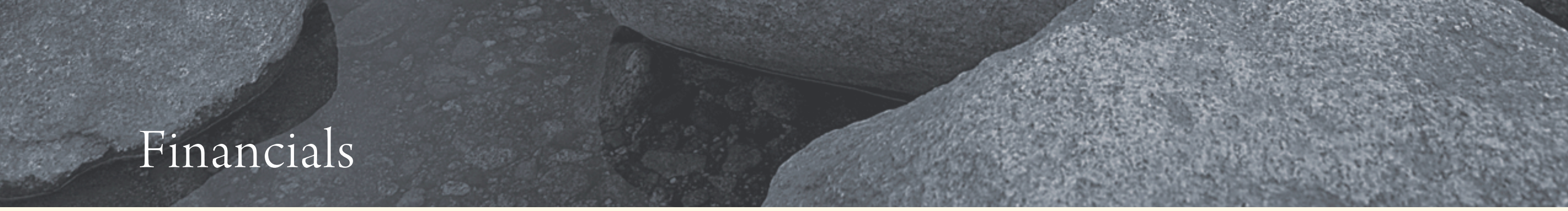
The Corporation's principal business of regulated gas and electric distribution utilities is capital intensive. Over the next five years, the Corporation's consolidated utility capital program is expected to exceed $4 billion. Most of its more than $3 billion gross electric utility capital expenditures over the next five years will be driven by FortisAlberta, FortisBC and the Corporation's regulated and non-regulated electric utility operations in the Caribbean. Gross gas utility capital expenditures are expected to exceed $1 billion. The Corporation's capital program should drive growth in earnings and dividends.

The Corporation continues to integrate Terasen within the Fortis Group. The addition of the gas distribution business doubled the Corporation's investment in regulated rate base assets to approximately $6.3 billion. The Corporation is pursuing acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Outstanding Share Data

At March 13, 2008, the Corporation had issued and outstanding 156,753,899 Common Shares; 5,000,000 First Preference Shares, Series C; 7,993,500 First Preference Shares, Series E and 5,000,000 First Preference Shares, Series F. As at December 31, 2007, the number of Common Shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E is described in Notes 10, 13, 14 and 15 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Additional information, including the Fortis 2007 Annual Information Form and Management Information Circular, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.



Financials

Management's Report

The accompanying Consolidated Financial Statements of Fortis Inc. and all information in the 2007 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2007 Annual Report is consistent with that in the Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee.

The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes. The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2007 Consolidated Financial Statements and Management Discussion and Analysis contained in the 2007 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2007 Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

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

St. John's, Canada

Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2007 and 2006 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

St. John's, Canada,
February 1, 2008

Ernst & Young LLP
Chartered Accountants

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions)

ASSETS	**2007**	2006
Current assets		
Cash and cash equivalents	**$ 58**	$ 41
Accounts receivable	**635**	286
Prepaid expenses	**19**	14
Regulatory assets *(Note 4)*	**119**	31
Inventories of gas, materials and supplies	**233**	33
	1,064	405
Deferred charges and other assets *(Note 5)*	**179**	174
Regulatory assets *(Note 4)*	**193**	140
Future income taxes *(Note 19)*	**37**	7
Utility capital assets *(Note 6)*	**6,722**	3,575
Income producing properties *(Note 7)*	**519**	469
Intangibles, net of amortization *(Note 2)*	**15**	10
Goodwill *(Note 8)*	**1,544**	661
	$ 10,273	$ 5,441
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 9)*	**$ 475**	$ 98
Accounts payable and accrued charges	**793**	333
Dividends payable	**43**	22
Income taxes payable	**30**	–
Regulatory liabilities *(Note 4)*	**20**	19
Current installments of long-term debt and capital lease obligations *(Note 10)*	**436**	85
Future income taxes *(Note 19)*	**7**	1
	1,804	558
Deferred credits *(Note 11)*	**261**	79
Regulatory liabilities *(Note 4)*	**372**	340
Future income taxes *(Note 19)*	**55**	58
Long-term debt and capital lease obligations *(Note 10)*	**4,623**	2,558
Non-controlling interest *(Note 12)*	**115**	130
Preference shares *(Note 13 (i) and (ii))*	**320**	320
	7,550	4,043
Shareholders' equity		
Common shares *(Note 14)*	**2,126**	829
Preference shares *(Note 13 (iii))*	**122**	122
Contributed surplus	**6**	5
Equity portion of convertible debentures *(Note 10)*	**6**	7
Accumulated other comprehensive loss *(Note 16)*	**(88)**	(51)
Retained earnings	**551**	486
	2,723	1,398
	$ 10,273	$ 5,441

Commitments *(Note 25)*

Contingent Liabilities *(Note 26)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Bruce Chafe,
Director

David G. Norris,
Director

Financials

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions, except per share amounts)	2007	2006
Operating Revenues	$ 2,718	$ 1,462
Equity Income	–	10
	2,718	1,472
Expenses		
Energy supply costs	1,287	540
Operating	617	399
Amortization	273	178
	2,177	1,117
Operating Income	541	355
Finance charges *(Note 17)*	299	168
Gain on sale of property *(Note 18)*	(8)	(2)
	291	166
Earnings Before Corporate Taxes and Non-Controlling Interest	250	189
Corporate taxes *(Note 19)*	36	32
Net Earnings Before Non-Controlling Interest	214	157
Non-controlling interest	15	8
Net Earnings	199	149
Preference share dividends	6	2
Net Earnings Applicable to Common Shares	$ 193	$ 147
Earnings Per Common Share *(Note 14)*		
Basic	$ 1.40	$ 1.42
Diluted	$ 1.32	$ 1.37

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions)	2007	2006
Balance at Beginning of Year	$ 486	$ 412
Net Earnings Applicable to Common Shares	193	147
	679	559
Dividends on Common Shares	(128)	(73)
Balance at End of Year	$ 551	$ 486

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions)	2007	2006
Net Earnings	$ 199	$ 149
Unrealized foreign currency translation losses	(70)	(30)
Gains (losses) on hedges of net investments in self-sustaining foreign operations	48	(6)
Corporate (taxes) recovery	(9)	1
Change in Unrealized Foreign Currency Translation Losses, Net of Hedging Activities and Tax *(Note 16)*	(31)	(35)
Comprehensive Income	$ 168	$ 114

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions)	**2007**	2006
Operating Activities		
Net earnings	**$ 199**	$ 149
Items not Affecting Cash		
Amortization – capital assets, net of contributions in aid of construction	**261**	168
Amortization – intangibles	**5**	4
Amortization – other	**7**	6
Future income taxes *(Note 19)*	**–**	10
Accrued employee future benefits	**(2)**	(3)
Non-controlling interest	**15**	8
Gain on sale of property *(Note 18)*	**(8)**	(2)
Other	**2**	(4)
Change in long-term regulatory assets and liabilities	**11**	(30)
Increase in corporate income tax deposit	**–**	(6)
	490	300
Change in non-cash operating working capital	**(117)**	(37)
	373	263
Investing Activities		
Change in deferred charges, other assets and deferred credits	**(4)**	(25)
Utility capital expenditures	**(790)**	(483)
Contributions in aid of construction	**73**	54
Income producing property capital expenditures	**(13)**	(17)
Proceeds on sale of capital assets	**4**	8
Business acquisitions, net of cash acquired *(Note 21)*	**(1,303)**	(169)
Increase in investments	**–**	(2)
	(2,033)	(634)
Financing Activities		
Change in short-term borrowings	**103**	38
Proceeds from long-term debt, net of issue costs	**1,400**	469
Repayments of long-term debt and capital lease obligations	**(941)**	(197)
Advances (to) from non-controlling interest	**(3)**	10
Issue of common shares, net of costs	**1,267**	15
Issue of preference shares, net of costs	**–**	121
Dividends		
Common shares	**(128)**	(73)
Preference shares	**(6)**	(2)
Subsidiary dividends paid to non-controlling interest	**(12)**	(2)
	1,680	379
Effect of exchange rate changes on cash and cash equivalents	**(3)**	–
Change in Cash and Cash Equivalents	**17**	8
Cash and Cash Equivalents, Beginning of Year	**41**	33
Cash and Cash Equivalents, End of Year	**$ 58**	$ 41

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

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 825,000 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 91,200 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.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving over 448,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 223 megawatts ("MW"). During 2007, the entitlement capacity and energy output for a number of FortisBC Inc.'s hydroelectric generating units were optimized as a result of past turbine and generator upgrade projects. Entitlement capacity was rebalanced from 235 MW to 223 MW and energy output increased by 11,000 MW hours as a result of negotiated adjustments to the Canal Plant Agreement with BC Hydro.

   Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC's assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 232,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 96 MW is hydroelectric generation.

d. *Maritime Electric:* Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 72,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW.

e. *FortisOntario:* FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000, serving more than 27,000 customers.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 73,000 customers. The Company has an installed generating capacity of 36 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 23,000 customers. The Company has an installed generating capacity of 137 MW. On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities' October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation's December 31, 2007 Consolidated Financial Statements. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, accounted for on an equity basis, on a two-month lag.

c. *P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") (collectively referred to as Fortis Turks and Caicos):* Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 8,700 customers. The Company has a combined diesel-fired generating capacity of 48 MW. Fortis Turks and Caicos was acquired by Fortis, through a wholly owned subsidiary, on August 28, 2006.

Non-Regulated – Fortis Generation

a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.

b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement ("NEA"), a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and Abitibi-Consolidated Corporation of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Since the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties has held directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement expiring in 2033.

December 31, 2007 and 2006

1. Description of the Business (cont'd)

Non-Regulated – Fortis Generation (cont'd)

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership ("WPP"), a wholly owned partnership of FortisBC Inc.

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 19 hotels with more than 3,500 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. Terasen was acquired by Fortis on May 17, 2007.

2. Summary of Significant Accounting Policies

These Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. These differences are described in Note 2, under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. The BCUC uses a future test year in the establishment of rates for the utilities and, pursuant to this method, forecasts the volume of gas that will be sold and transported for TGI and TGVI, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGVI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGVI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGVI have been extended until 2009. During 2006, the BCUC approved a PBR agreement for FortisBC with a term from 2006 to 2008, with an option to extend the term to 2009. Under the PBR agreement, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.37 per cent for 2007 (2006 – 8.80 per cent) on a deemed capital structure of 35 per cent equity. TGVI's allowed ROE was 9.07 per cent for 2007 (2006 – 9.50 per cent) on a deemed capital structure of 40 per cent equity. FortisBC's allowed ROE was 8.77 per cent for 2007 (2006 – 9.20 per cent) on a deemed capital structure of 40 per cent equity. The allowed ROE at each of TGI, TGVI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. TGI, TGVI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and operation of the PBR mechanisms.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing. Prior to January 1, 2008, the Alberta Energy and Utilities Board ("AEUB") was the chief provincial regulator of the Alberta energy industry. Effective January 1, 2008, the *Alberta Utilities Commission Act* separated the AEUB into two separate regulatory bodies: the Energy Resource and Conservation Board and the AUC. Any use herein of the term "AUC" will refer to the AEUB prior to January 1, 2008 and the AUC subsequently.

FortisAlberta operates under cost-of-service regulation as prescribed by the AUC. The AUC uses a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.51 per cent for 2007 (2006 – 8.93 per cent) on a deemed capital structure of 37 per cent equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields.

The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost-of-service regulation as administered by the PUB. The PUB uses a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined. In between test years, Newfoundland Power's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. Newfoundland Power's allowed ROE for 2007 was 8.60 per cent (2006 – 9.24 per cent) on a deemed capital structure of 45 per cent equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

December 31, 2007 and 2006

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

Regulation (cont'd)

Maritime Electric

Maritime Electric operates under a traditional cost-of-service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). The IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 10.25 per cent for 2007 (2006 – 10.25 per cent) on a deemed capital structure of 40 per cent equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost-of-service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. The electricity distribution rates are based upon costs associated with a historical test year, 2004, using a deemed capital structure of 50 per cent equity. FortisOntario's allowed ROE was 9.0 per cent for 2007 (2006 – 9.0 per cent).

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, dated July 31, 1998. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The primary duty of the PUC is to ensure that the services rendered by the Company are satisfactory and that the charges imposed in respect of those services are fair and reasonable. The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. Basic electricity rates for Belize Electricity are comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and allowed rate of return on rate base assets ("ROA") in the range of 10 per cent to 15 per cent. The VAD component of the tariff is normally reviewed every four years, while the COP component and any rate stabilization account ("RSA") recovery are reviewed at each annual rate proceeding and at Threshold Event Review Proceedings, which can occur when the deferrals of COP into the RSA exceed $1.5 million (BZ$3 million).

Effective for the full (four-year) tariff period beginning July 1, 2007, if the achieved ROA at the end of the full tariff period is below 10 per cent or above 15 per cent, rates are adjusted over the course of the next full tariff period.

Caribbean Utilities

Caribbean Utilities generates and distributes electricity in its exclusive licence area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government"), originally dated May 10, 1966, amended November 1, 1979 and renewed for a further 25 years on January 17, 1986 (collectively, the "Licence"). The Licence allows for subscribers' tariffs to be adjusted annually to provide Caribbean Utilities with an allowed ROA of 15 per cent, as defined in the Licence.

An agreement in principle ("AIP") was reached with the Government in December 2007 on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year transmission and distribution licence for Caribbean Utilities. The new licences are expected to be issued in the first half of 2008, with impact on customer rates effective January 1, 2008. The AIP will see the replacement of the current allowed ROA of 15 per cent with a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates will now be set using an initial targeted ROA of 10 per cent. The AIP details the role of the Electric Regulatory Authority which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an ROA of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfall. The submissions for 2007 calculated the Allowable Operating Profit for 2007 to be $12 million (US$12 million) and the cumulative shortfall at December 31, 2007 to be $8 million (US$8 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

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

Inventories of Gas, Materials and Supplies

Inventories of gas in storage are valued at weighted-average cost. Materials and supplies are valued at the lower of average cost and market value, determined on the basis of estimated net realizable value.

Deferred Charges and Credits and Other Assets

Deferred charges and credits and other assets include deferred pension costs, accrued pension obligations, Alberta Electric System Operator ("AESO") contributions, deferred recoverable and project costs, deferred gains on sale of natural gas transmission and distribution assets, deferred payments, energy management loans, a corporate income tax deposit, an investment held at Fortis Properties as collateral for a loan, customer deposits, investments, long-term receivables, lease costs and other deferred charges and credits. AESO contributions represent payments to the AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through AUC-approved amortization rates. Deferred recoverable costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties. Energy management loans range in terms from one year to 10 years and are deferred until they are recovered from customers. The corporate income tax deposit relates to Maritime Electric's tax reassessment (Note 26). Other deferred charges and assets are recorded at cost and are amortized over the estimated period of future benefit.

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of $21 million, as at January 1, 2007, relating to long-term debt were reclassified from deferred charges and other assets to long-term debt on the balance sheet (Note 5).

As at January 1, 2007, in accordance with the transitional provisions of Section 3865, *Hedges*, unamortized deferred gain and loss balances related to previously cancelled swap agreements were reclassified to accumulated other comprehensive loss (Note 16). An unamortized loss balance of $11 million ($7 million after-tax), as at January 1, 2007, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets (Note 5), and an unamortized gain balance of $3 million ($2 million after-tax), as at January 1, 2007, related to a previously cancelled US dollar forward-currency swap agreement, was reclassified from deferred credits (Note 11).

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

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US$2.00, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent the cost of utility capital assets contributed by customers and governments. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2007, the long-term regulatory liability for future removal and site restoration costs was $319 million (December 31, 2006 – $307 million) (Note 4 *(xiv)*). The Terasen Gas companies record actual removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2007. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record removal and site restoration costs in earnings when incurred and these costs did not have a material impact on the Corporation's 2007 and 2006 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by their respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario, Caribbean Utilities and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets, is recorded immediately in earnings.

In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2007 was approximately $22 million (2006 – $22 million).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets, but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2007, GEC totalled $40 million (2006 – $18 million).

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by their respective regulators, include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges, and AFUDC capitalized during 2007 was $8 million (2006 – $4 million) (Note 17), including an equity component of $3 million (2006 – $2 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2007, amortization expense was reduced by $5 million (2006 – $5 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 33.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2007 was 3.6 per cent (2006 – 4.2 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission and generation assets as at December 31st were as follows.

	2007		2006	
	Service Life Ranges (Years)	**Average Remaining Service Life (Years)**	**Service Life Ranges (Years)**	**Average Remaining Service Life (Years)**
Distribution				
Gas	**10–100**	**33**	–	–
Electric	**10–75**	**28**	10–75	27
Transmission				
Gas	**10–50**	**38**	–	–
Electric	**10–75**	**34**	10–75	30
Generation	**5–75**	**32**	5–75	31

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate, except where a write-down is required to reflect a permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of two years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Intangibles

Intangibles include the estimated fair value of water rights associated with the Rankine Generating Station in Ontario and intangibles associated with the acquisition of Terasen. The water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. Effective May 1, 2009, in accordance with the NEA, FortisOntario's water entitlement on the Niagara River associated with the Rankine Generating Station will not be renewed and earnings' contribution associated with the NEA will cease.

Upon the acquisition of Terasen, $10 million was assigned as the value associated with customer contracts at CWLP. The intangible is being amortized using the straight-line method over the remaining term of the contracts to December 31, 2011. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization. As at December 31, 2007, the net book value of intangibles was $15 million (net of accumulated amortization of $21 million) (2006 – $10 million (net of accumulated amortization of $15 million)).

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

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives, deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period it is identified. There was no impact on the financial statements as a result of asset-impairments for the years ended December 31, 2007 and 2006.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the economic value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's economic value, including a fair return on capital, is provided through customer gas and electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset specific but are pooled for the entire regulated enterprise.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs, or if circumstances change, that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2007 and 2006.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans
The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of Terasen and Newfoundland Power, pension plan assets are valued at fair value. At Terasen and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at Terasen and Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(ix)* and *(xvi)*).

Other Post-Employment Benefit ("OPEB") Plans

The Corporation, Terasen, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, Terasen, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with these OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation, at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

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

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

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under the Corporation's 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 15). Compensation expense is measured at the date of grant using the Black-Scholes fair value option pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option price and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

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

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining, are translated at the exchange rate in effect at the balance sheet dates. The exchange rate in effect at December 31, 2007 was US$1.00 = CDN$0.99 (December 31, 2006 – US$1.00 = CDN$1.17). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income (loss) and the current period change is recorded in the statement of comprehensive income (loss). Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in the statement of comprehensive income (loss).

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in the statement of earnings.

December 31, 2007 and 2006

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

Financial Instruments

Effective January 1, 2007, the Corporation adopted Section 3855, *Financial Instruments – Recognition and Measurement* and Section 3861, *Financial Instruments – Disclosure and Presentation*.

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

All derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income (loss). Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the rate-regulated utilities, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4).

Currently, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

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

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

Hedging Relationships

Effective January 1, 2007, the Corporation adopted Section 3865, *Hedges*.

At December 31, 2007, the Corporation's hedging relationships consisted of interest rate swap contracts, natural gas commodity swap and option contracts, and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Fortis Properties and the Terasen Gas companies have designated their interest rate swap contracts as hedges of the cash flow risk related to floating-rate debt. The interest rate swap contracts are valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of Fortis Properties' interest rate swap contracts that are in effective hedging relationships are recorded in other comprehensive income (loss). Any changes in the fair value of the interest rate swaps of the Terasen Gas companies, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices and natural gas commodity swaps and options are used, therefore, to fix the effective purchase price of natural gas. As at December 31, 2007, none of the natural gas commodity swaps and options were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas commodity swaps and options, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator. The fair values of the natural gas commodity swaps and options reflect the estimated amounts that the Terasen Gas companies would pay to terminate the contracts as at December 31, 2007.

The Corporation's foreign net investments are exposed to changes in the US dollar exchange rate and the Corporation has reduced its exposure to foreign currency exchange rate fluctuations on a substantial portion of its foreign net investments through the use of US dollar borrowings. The Corporation has designated its US dollar-denominated long-term debt as a hedge of the foreign currency exchange risk related to its net investments in US dollar-denominated self-sustaining foreign operations. In the hedge of net investments in self-sustaining foreign operations, the unrealized gains and losses on the translation of the US dollar-denominated long-term debt serve to offset unrealized foreign currency exchange gains and losses on foreign net investments. The unrealized foreign currency exchange gains and losses on the US dollar-denominated long-term debt and the foreign net investments are recognized in other comprehensive income (loss).

Income Taxes

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the taxes-payable method of accounting for income taxes, as prescribed by their respective regulator. Under this methodology, current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. In the absence of rate regulation, future income tax assets and liabilities are recorded and the Corporation's future income tax liabilities and future income tax assets would have increased by approximately $344 million and $29 million, respectively, at December 31, 2007 (December 31, 2006 – $127 million and $56 million, respectively).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of gas and electricity by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Gas and electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 *(xv)*).

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

Revenue Recognition (cont'd)

FortisAlberta reports revenues and expenses related to transmission services on a net basis in other revenue. At the Corporation's other regulated utilities, transmission revenues and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with AESO and collect transmission revenue from its customers, which is done through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected, or refunded, in future customer rates (Note 4 *(v)*).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these costs, and revenue associated with the recovery of these costs, are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generating operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generating stations is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue.

The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs are recorded as a liability at fair value, with a corresponding increase to utility capital assets and income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

The Corporation has AROs associated with hydroelectric generating facilities, and with interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified to date in respect of the Corporation's hydroelectric generating facilities. These facilities are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and to ensure the continued provision of electricity service to customers. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of removal costs cannot be reasonably determined at this time.

The Corporation has determined that an ARO exists regarding the remediation of leased land on which a pumphouse is currently situated at Maritime Electric. The pumphouse is integral to the Company's operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. An ARO associated with land remediation will be recorded when the lease is terminated at the request of the lessor and the costs are reasonably estimable.

On April 1, 2006, Fortis retroactively adopted Emerging Issues Committee Abstract EIC 159, *Conditional Asset-Retirement Obligations* ("EIC 159"). EIC 159 requires an entity to recognize a liability for the fair value of an ARO even though the timing and/or method of settlement are conditional on future events. While conditional AROs have been identified, no amounts have been recorded as they are immaterial to the Corporation's results of operations and financial position.

Accounting Changes

Effective January 1, 2007, the Corporation adopted the revised Section 1506, *Accounting Changes*, relating to changes in accounting policies, changes in accounting estimates, and errors.

Under revised Section 1506, voluntary changes in accounting policies are made only if they result in the financial statements providing reliable and more relevant information. Additional disclosure is required when the Corporation has not applied a new primary source of Canadian GAAP that has been issued but is not yet effective, as well as when changes in accounting estimates and errors occur. Adoption of this revised standard had no impact on the Corporation's 2007 Consolidated Financial Statements except for the disclosures provided in Note 3.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period. In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-oriented enterprises. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010. While Fortis has begun assessing the adoption of IFRS for 2011, the financial reporting impact on the Corporation of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations

In August 2007, the AcSB issued a Decision Summary that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation. The AcSB also amended Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets as well as offsetting regulatory assets and liabilities at entities subject to rate regulation. Both changes will apply prospectively for the Corporation beginning on January 1, 2009. The AcSB also decided that the current guidance for rate-regulated operations pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained, and that the existing Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate-regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as "another source of GAAP" within the Canadian GAAP hierarchy.

3. Future Accounting Pronouncements (cont'd)

Rate-Regulated Operations (cont'd)

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the taxes-payable method of accounting for income taxes. The effect on the Corporation's Consolidated Financial Statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2007, would have been an increase in future tax assets and future tax liabilities of $54 million and $489 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of $54 million and $489 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates, and the separate disclosure of future income tax assets and liabilities that are currently not recognized. Fortis is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Inventories

Effective January 1, 2008, the Corporation will be adopting the new Section 3031, *Inventories*. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in, first-out inventory-costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Corporation's earnings, cash flow or financial position.

Capital Disclosures

As a result of new Section 1535, *Capital Disclosures*, Fortis will be required to include additional information in the Notes to the Consolidated Financial Statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. This Section is applicable to Fortis for the fiscal year beginning on January 1, 2008.

Disclosure and Presentation of Financial Instruments

New accounting recommendations for disclosure and presentation of financial instruments, Sections 3862 and 3863, are effective for the Corporation beginning on January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

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

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

Regulatory Assets *(in millions)*	**2007**	2006	**Remaining recovery period (Years)**
Rate stabilization accounts – Terasen Gas companies *(i)*	**$ 99**	$ –	1–3
Rate stabilization accounts – electric utilities *(ii)*	**55**	44	Various
Regulatory OPEB asset *(iii)*	**44**	36	Various
Income taxes recoverable on OPEB plans *(iv)*	**16**	–	Various
AESO charges deferral *(v)*	**8**	40	2
Deferred capital asset amortization *(vi)*	**12**	6	1–3
Weather normalization account *(vii)*	**11**	12	Not determinable
Residential unbundling *(viii)*	**9**	–	1–3
Deferred pension costs *(ix)*	**8**	9	8
Southern Crossing Pipeline tax reassessment *(x)*	**7**	–	Not determinable
Energy management costs *(xi)*	**6**	6	8
Lease costs *(xii)*	**5**	4	16–28
Other regulatory assets *(xiii)*	**32**	14	1–28
Total regulatory assets	**312**	171	
Less: current portion	**(119)**	(31)	1
Long-term regulatory assets	**$ 193**	$ 140	

Regulatory Liabilities *(in millions)*	**2007**	2006	**Remaining settlement period (Years)**
Future removal and site restoration provision *(xiv)*	**$ 319**	$ 307	Not determinable
Unbilled revenue liability *(xv)*	**22**	25	Not determinable
Pension deferral *(xvi)*	**6**	4	1–7
PBR incentive liabilities *(xvii)*	**14**	3	1–2
Other regulatory liabilities *(xviii)*	**31**	20	1–5
Total regulatory liabilities	**392**	359	
Less: current portion	**(20)**	(19)	1
Long-term regulatory liabilities	**$ 372**	$ 340	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Rate Stabilization Accounts – Terasen Gas companies*

The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility, caused principally by weather, and natural gas cost volatility. At TGI, a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers.

Additionally, a Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The MCRA captures the gas cost variances applicable to all sales customers while the CCRA accumulates gas cost variances applicable to all residential customers and certain industrial customers for whom TGI acquires gas supply.

December 31, 2007 and 2006

4. Regulatory Assets and Liabilities (cont'd)

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

(i) *Rate Stabilization Accounts – Terasen Gas companies (cont'd)*

At TGVI, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. TGVI also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed an allowed ROE as set by the BCUC. The RDDA has accumulated the allowed earnings in excess of achieved earnings prior to 2003 and is to be recovered through future rates. During 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be recovered through rates over a three-year period, with a total balance outstanding at December 31, 2007 of $18 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered within the next fiscal year. Recovery of the rate stabilization accounts is dependent on actual natural gas consumption and recovery amounts approved by the BCUC.

(ii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered or refunded through customer rates as approved by the respective regulatory authorities. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or pre-determined level. Additionally, in the case of Belize Electricity, a rate stabilization account is used to defer and recover hurricane damage and recovery expenses from customers. The recovery period of the rate stabilization accounts is variable and is subject to periodic review by the respective regulatory authorities.

On July 1st of each year, the rate charged to Newfoundland Power's customers is recalculated in order to amortize, over the subsequent 12 months, the balance in its rate stabilization account as of December 31st of the previous year. In the absence of rate regulation, the costs deferred to Newfoundland Power's rate stabilization account would continue to be accounted for in a similar manner; however, the amount recovered and the recovery period would not be subject to regulatory approval.

The rate of recovery of the Cost of Power Rate Stabilization Account ("CPRSA") and Hurricane Cost Recovery Rate Stabilization Account ("HCRSA") at Belize Electricity is recalculated on July 1st of each year based on the balance in the CPRSA and HCRSA as of the preceding year end, but may be adjusted at any time as a result of a threshold event.

As at December 31, 2007, $14 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of seven years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period.

Except as described for Newfoundland Power, in the absence of rate regulation, the cost of fuel and/or purchased power would be expensed as incurred.

(iii) *Regulatory OPEB Asset*

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by their respective regulators. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of OPEB plans.

The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(iv) *Income Taxes Recoverable on OPEB Plans*

At TGI, the regulator allows OPEB costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which produces timing differences for income tax purposes. Since TGI accounts for income taxes using the taxes-payable method, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(v) AESO Charges Deferral

FortisAlberta maintains an AESO Charges Deferral Account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral to be collected in future customer rates. In the event that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be either refunded to customers through a reduction in future rates or recognized when additional costs are incurred. As approved by the AUC, $13 million of the December 31, 2006 AESO Charges Deferral Account balance was collected from customers during 2007. As at December 31, 2007, the balance of the AESO Charges Deferral Account is expected to be collected in customer rates through 2008 and 2009. In the absence of rate regulation, the costs would be expensed as incurred and no deferral treatment would be permitted.

During 2007, FortisAlberta sold approximately $28 million and $38 million of the 2006 and 2007 AESO Charges Deferral Accounts, respectively, to a Canadian chartered bank for proceeds of approximately $28 million and $38 million, respectively. Proceeds included cash consideration of $64 million and receivables of approximately $2 million due in February 2009 and 2010 (Note 5).

(vi) Deferred Capital Asset Amortization

Newfoundland Power deferred the recovery of a $6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The approximate $12 million balance at December 31, 2007 will be amortized as an increase in operating expenses and included in customer rates equally over the next three years. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(vii) Weather Normalization Account

The PUB has ordered the provision of a weather normalization account at Newfoundland Power to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The balance in the weather normalization account should approach to zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately $7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, these fluctuations would be recorded in earnings in the period in which they occurred.

The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

(viii) Residential Unbundling

Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. The balance at December 31, 2007 will be recovered from customers commencing in 2008. In the absence of rate regulation, these costs would have been expensed when incurred.

(ix) Deferred Pension Costs

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

(x) Southern Crossing Pipeline Tax Reassessment

The Southern Crossing Pipeline tax-reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to $7 million and the overpayment was refunded to TGI. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable pending resolution of the appeal. Any final assessed tax upon resolution of the appeal would be expensed in the period it becomes known (Note 26).

December 31, 2007 and 2006

4. Regulatory Assets and Liabilities (cont'd)

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

(xi) *Energy Management Costs*

FortisBC provides energy management services to promote energy-efficiency programs to its customers. As required by a BCUC order, the Company has capitalized all related expenditures (except certain defined costs) and is amortizing these expenditures on a straight-line basis at 12.5 per cent per annum. This regulatory asset represents the unamortized balance of the energy management costs, which are expected to be recovered from customers in rates over an average of eight years, based on the terms of the currently approved BCUC order. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(xii) *Lease Costs*

On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination) (the "BTS Obligation") (Note 10). The agreement provides that FortisBC will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. Costs related to the BTS are not being fully recovered by the Company in current customer rates. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, amortization of the BTS and interest on the BTS Obligation would have been recorded in the period incurred.

Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term (Note 25). The Company is accounting for the lease as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term. As ordered by the BCUC, FortisBC recovers the Trail office lease payments from customers and records the lease costs on a cash basis. In the absence of rate regulation, the lease costs would be recorded on a straight-line basis.

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

(xiii) *Other Regulatory Assets*

Other regulatory assets primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. The balance is comprised of various items each individually less that $5 million. As of December 31, 2007, $22 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. The recovery periods range from one to 28 years. As of December 31, 2007, $4 million (2006 – $4 million) of the balance was not subject to a regulatory return.

In the absence of rate regulation, the deferrals would not be permitted.

(xiv) *Future Removal and Site Restoration Provision*

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for these future removal and site restoration costs, net of salvage proceeds. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulators. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in this regulatory liability with the offset recorded as an adjustment to accumulated amortization.

During 2007, the amount included in amortization expense associated with the provision for future removal and site restoration costs was $33 million (2006 – $30 million). During 2007, actual removal and site restoration costs, net of salvage proceeds, were $19 million (2006 – $4 million). In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xv) *Unbilled Revenue Liability*

Belize Electricity records revenue derived from electricity sales on a billed basis (Note 2). Prior to January 1, 2006, Newfoundland Power also recorded revenue from electricity sales on a billed basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to the accrual basis, as approved by the PUB. As a result, the $24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $3 million of this regulatory liability in 2007 (2006 – $3 million). The unamortized balance at December 31, 2007 will be amortized as follows: 2008 – approximately $7 million, 2009 and 2010 – approximately $5 million in each year. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not be permitted.

(xvi) *Pension Deferral*

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

(xvii) *PBR Incentive Liabilities*

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders (Note 2).

TGI's 2007 regulatory PBR incentive liability of $13 million is expected to be refunded to customers through reduced rates beginning in 2009. FortisBC's 2006 regulatory PBR incentive liability of $3 million was approved by the BCUC for settlement in 2007 through a reduction in 2007 electricity revenue, with an offsetting increase in other revenue. Based on the current PBR framework, FortisBC's 2007 regulatory PBR incentive liability of $1 million has been approved by the BCUC for settlement in 2008 through a reduction in 2008 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xviii) *Other Regulatory Liabilities*

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and Fortis Ontario. The balance is comprised of various items each individually less that $5 million. As of December 31, 2007, $15 million of the balance was approved for refund to future customers or reduction in future rates, with the remaining balance expected to be approved. The recovery periods range from one to five years. As of December 31, 2007, $7 million (2006 – $10 million) of the balance was not subject to a regulatory return.

In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

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

(in millions)	**2007**	2006
Decrease in regulatory assets	**$ (303)**	$ (167)
Decrease in regulatory liabilities	**(392)**	(359)
Decrease in opening retained earnings	**(108)**	(162)
Increase in revenue	**343**	18
Increase (decrease) in energy supply costs	**340**	(15)
Increase in operating expense	**62**	10
Decrease in amortization expense	**(28)**	(25)
Increase in finance charges	**3**	2
(Decrease) increase in corporate taxes	**(15)**	16

December 31, 2007 and 2006

5. Deferred Charges and Other Assets

(in millions)	**2007**	2006
Deferred pension costs *(Note 20)*	**$ 120**	$ 93
AESO contributions	**19**	17
Long-term receivables – TGI (due 2040)	**7**	–
Deferred recoverable and project costs	**7**	10
Energy management loans	**6**	4
Corporate income tax deposit	**6**	6
Investment held as collateral	**3**	3
Investments	**2**	2
Long-term receivable – AESO charges deferral *(Note 4 (v))*	**2**	–
Other deferred charges	**7**	7
Deferred financing costs	**–**	21
Deferred loss on interest rate swap agreement	**–**	11
	$ 179	$ 174

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of $21 million at January 1, 2007 relating to long-term debt have been reclassified from deferred charges and other assets to long-term debt (Note 10).

As of January 1, 2007, in accordance with the transitional provision of Section 3865, *Hedges*, an unamortized deferred loss balance of $11 million, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets to accumulated other comprehensive loss (Note 16).

6. Utility Capital Assets

2007 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution					
Gas	**$ 2,233**	**$ (364)**	**$ (174)**	**$ –**	**$ 1,695**
Electric	**3,536**	**(961)**	**(463)**	**(91)**	**2,021**
Transmission					
Gas	**1,277**	**(286)**	**(102)**	**–**	**889**
Electric	**870**	**(224)**	**–**	**–**	**646**
Generation	**915**	**(240)**	**–**	**–**	**675**
Assets under construction	**155**	**–**	**–**	**–**	**155**
Other	**992**	**(337)**	**(14)**	**–**	**641**
	$ 9,978	**$ (2,412)**	**$ (753)**	**$ (91)**	**$ 6,722**

2006 (in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Electric Distribution	$ 3,223	$ (864)	$ (426)	$ (96)	$ 1,837
Electric Transmission	818	(229)	–	–	589
Generation	903	(245)	–	–	658
Assets under construction	130	–	–	–	130
Other	552	(191)	–	–	361
	$ 5,626	$ (1,529)	$ (426)	$ (96)	$ 3,575

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires and conductors, substations, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include land and land rights, buildings, equipment, vehicles and information technology assets.

The cost of utility capital assets under capital lease at December 31, 2007 was $51 million (2006 – $27 million) and related accumulated amortization was $19 million (2006 – $3 million).

7. Income Producing Properties

2007

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

2006

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 421	$ (35)	$ 386
Land	51	–	51
Tenant inducements	17	(11)	6
Equipment	40	(15)	25
Construction in progress	1	–	1
	$ 530	$ (61)	$ 469

The cost of income producing property assets under capital lease at December 31, 2007 was $6 million (2006 – $11 million) and related accumulated amortization was $4 million (2006 – $7 million).

December 31, 2007 and 2006

8. Goodwill

(in millions)	**2007**	2006
Balance, beginning of year	**$ 661**	$ 512
Acquisition of Terasen *(Note 21)*	**907**	–
Reversal of restructuring accrual	**(2)**	–
Acquisition of controlling interest in Caribbean Utilities *(Note 21)*	**–**	106
Acquisition of Fortis Turks and Caicos *(Note 21)*	**–**	39
Foreign exchange translation impacts	**(22)**	4
Balance, end of year	**$ 1,544**	$ 661

Goodwill associated with the acquisition of a controlling interest in Caribbean Utilities on November 7, 2006 and the acquisition of Fortis Turks and Caicos on August 28, 2006 is denominated in US dollars as the investment in these companies is held through a wholly owned subsidiary of Fortis with a reporting currency in US dollars. Foreign currency translation impacts in 2007 and 2006 were the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

9. Credit-Facility Borrowings

The credit facilities of the Corporation and its subsidiaries, as summarized below, bear interest at rates ranging from 4.6 per cent to 6.2 per cent at December 31, 2007 (December 31, 2006 – 4.5 per cent to 6.8 per cent). As at December 31, 2007, the Corporation and its subsidiaries had consolidated authorized lines of credit of $2.2 billion, of which $1.1 billion was unused.

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2007**	Total as at December 31, 2006
Total credit facilities	$ 715	$ 1,506	$ 13	**$ 2,234**	$ 952
Credit facilities utilized					
Short-term borrowings	(6)	(468)	(1)	**(475)**	(98)
Long-term debt *(Note 10)*	(208)	(322)	–	**(530)**	(235)
Letters of credit outstanding	(55)	(103)	(1)	**(159)**	(72)
Credit facilities available	$ 446	$ 613	$ 11	**$ 1,070**	$ 547

At December 31, 2007 and December 31, 2006, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

At December 31, 2007, Terasen Inc. had a $100 million unsecured committed revolving credit facility, maturing in May 2009 that is available for general corporate purposes. Letters of credit outstanding of $55 million at Terasen Inc., related to its previously owned petroleum transportation business, are secured by a letter of credit from the former parent company.

During 2007, Fortis cancelled its $50 million unsecured revolving committed credit facility, and renegotiated and amended its $250 million unsecured committed credit facility, extending the maturity date to May 2012 and increasing the amount available to $600 million. Fortis also has a $15 million unsecured demand facility.

Regulated Utilities

At December 31, 2007, TGI had a $500 million unsecured committed revolving credit facility maturing in August 2012. At December 31, 2007, TGVI had a $350 million unsecured committed revolving credit facility, maturing in January 2011. These facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also had a $20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

In May 2007, FortisAlberta terminated one of its $10 million unsecured demand credit facilities, leaving one unsecured demand credit facility of $10 million available to the Company, and the maturity date of FortisAlberta's $200 million unsecured committed credit facility was extended to May 2012 from May 2010. The $200 million facility is utilized to finance capital expenditures and for general corporate purposes, and with the consent of the lenders, the amount of the facility can be increased to $250 million.

In May 2007, FortisBC renegotiated and amended its $150 million unsecured committed revolving credit facility, reallocating the amounts available between the 364-day portion of the facility and the three-year portion of the facility, and extending the maturity date for the three-year facility to May 2010 from May 2008. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a $10 million unsecured demand facility.

Newfoundland Power has unsecured credit facilities of $120 million, comprised of a $100 million committed revolving credit facility which matures in January 2009 and a $20 million uncommitted demand facility.

During 2007, Maritime Electric increased its unsecured revolving credit facility to $45 million from $30 million. Maritime Electric also has a $25 million unsecured credit facility maturing in May 2008.

FortisOntario has secured lines of credit totalling $16 million, of which $10 million is authorized solely for letters of credit.

On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit from US$13 million to US$19 million, including amounts available for letters of credit, and increasing each of its US$5 million operating line of credit and US$5 million catastrophe standby loan to US$7.5 million.

In November 2007, Fortis Turks and Caicos increased its operating credit facilities to US$5 million from US$2 million and obtained a US$7 million capital expenditure line of credit. Fortis Turks and Caicos also has available a US$9 million emergency standby loan.

Belize Electricity has a BZ$11 million unsecured demand overdraft credit facility.

Fortis Properties

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

December 31, 2007 and 2006

10. Long-Term Debt and Capital Lease Obligations

(in millions)	**2007**	2006
Regulated Utilities		
Terasen Gas companies		
Secured Purchase Money Mortgages:		
11.80% $75 million Series A, due 2015	**$ 75**	$ –
10.30% $200 million Series B, due 2016	**200**	–
Unsecured Debentures:		
10.75% $60 million Series E, due 2009	**60**	–
6.20% $188 million Series 9, due 2008	**188**	–
6.95% $150 million Series 11, due 2029	**150**	–
6.50% $150 million Series 18, due 2034	**150**	–
5.90% $150 million Series 19, due 2035	**150**	–
5.55% $120 million Series 21, due 2036	**120**	–
6.00% $250 million Series 22, due 2037	**250**	–
$6 million repayable Government loan, due 2008	**6**	–
Obligation under capital lease, due 2012	**9**	–
	1,358	–
FortisAlberta		
5.33% $200 million Senior Unsecured Debentures, due 2014	**200**	200
6.22% $200 million Senior Unsecured Debentures, due 2034	**200**	200
5.40% $100 million Senior Unsecured Debentures, due 2036	**100**	100
4.99% $110 million Senior Unsecured Debentures, due 2047	**110**	–
	610	500
FortisBC		
Secured Debentures:		
11.00% $15 million Series E, due 2009	**5**	5
9.65% $15 million Series F, due 2012	**15**	15
8.80% $25 million Series G, due 2023	**25**	25
Unsecured Debentures:		
6.75% $50 million Series J, due 2009	**50**	50
5.48% $140 million Series 04-1, due 2014	**140**	140
8.77% $25 million Series H, due 2016	**25**	25
7.81% $25 million Series I, due 2021	**25**	25
5.60% $100 million Series 05-1, due 2035	**100**	100
5.90% $105 million Series 07-1, due 2047	**105**	–
Obligation under capital lease, due 2032	**26**	27
	516	412

(in millions)	2007	2006
Newfoundland Power		
Secured first mortgage sinking fund bonds:		
11.875% $40 million Series AC, due 2007	**–**	32
10.550% $40 million Series AD, due 2014	**31**	32
10.900% $40 million Series AE, due 2016	**34**	34
9.000% $40 million Series AG, due 2020	**35**	35
10.125% $40 million Series AF, due 2022	**34**	34
8.900% $40 million Series AH, due 2026	**36**	36
6.800% $50 million Series AI, due 2028	**46**	46
7.520% $75 million Series AJ, due 2032	**71**	72
5.441% $60 million Series AK, due 2035	**58**	59
5.901% $70 million Series AL, due 2037	**69**	–
	414	380
Maritime Electric		
Secured first mortgage bonds:		
12.000% $15 million, due 2010	**15**	15
11.500% $12 million, due 2016	**12**	12
8.550% $15 million, due 2018	**15**	15
7.570% $15 million, due 2025	**15**	15
8.625% $15 million, due 2027	**15**	15
8.920% $20 million, due 2031	**20**	20
	92	92
FortisOntario		
7.092% $30 million Senior Unsecured Notes, due 2018	**30**	30
7.092% $22 million Senior Unsecured Notes, due 2018	**22**	22
	52	52
Belize Electricity		
Secured:		
5.75% to 8.15% US$14 million RBTT Merchant Bank loan, due 2010 to 2012 (December 31, 2007 – US$6 million)	**6**	9
Unsecured:		
12.00% BZ$27 million Series I Debentures, due 2012 (December 31, 2007 – BZ$17 million)	**8**	10
9.50% BZ$20 million Series II Debentures, due 2021 (December 31, 2007 – BZ$19 million)	**10**	11
10.00% BZ$25 million Series III Debentures, due 2022 (December 31, 2007 – BZ$25 million)	**12**	14
10.00% BZ$6 million Series IV Debentures, due 2027 (December 31, 2007 – BZ$6 million)	**3**	–
8.50% US$16 million Caribbean Development Bank loan, due 2014 (December 31, 2007 – US$7 million)	**7**	9
5.00% Euro$4 million European Investment Bank loan, due 2014 (December 31, 2007 – Euro$4 million)	**3**	3
US$11 million International Bank for Reconstruction and Development loan ("IBRD"), due 2011 (December 31, 2007 – US$3 million)	**3**	5
5.75% US$5 million Toronto Dominion Bank loan, due 2009 (December 31, 2007 – US$1 million)	**1**	3
BZ$10 million Bank of Nova Scotia loan, due 2015 (December 31, 2007 – BZ$9 million)	**4**	3
US$3 million Scotiabank & Trust (Cayman) Limited loan, due 2010 (December 31, 2007 – US$3 million)	**3**	4
	60	71

December 31, 2007 and 2006

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

(in millions)	2007	2006
Caribbean Utilities		
Unsecured:		
3.00% US$2 million European Investment Bank Loan #3, due 2009 (December 31, 2007 – US$1 million)	**1**	1
8.47% US$15 million Senior Loan Notes, due 2010 (December 31, 2007 – US$4 million)	**4**	7
6.47% US$25 million Senior Loan Notes, due 2013 (December 31, 2007 – US$15 million)	**15**	20
7.64% US$30 million Senior Loan Notes, due 2014 (December 31, 2007 – US$21 million)	**21**	28
6.67% US$30 million Senior Loan Notes, due 2016 (December 31, 2007 – US$26 million)	**26**	35
5.09% US$40 million Senior Loan Notes, due 2018 (December 31, 2007 – US$40 million)	**40**	47
5.96% US$30 million Senior Loan Notes, due 2020 (December 31, 2007 – US$30 million)	**30**	35
5.65% US$40 million Senior Loan Notes, due 2022 (December 31, 2007 – US$40 million)	**40**	–
	177	173
Fortis Turks and Caicos		
Unsecured:		
5.65% US$5 million First Caribbean International Bank loan, due 2015 (December 31, 2007 – US$3 million)	**3**	6
US$13 million Scotiabank (Turks and Caicos) Ltd. loan, due 2013 to 2016 (December 31, 2007 – US$13 million)	**13**	17
	16	23
Non-Regulated – Fortis Generation		
Secured:		
BECOL		
US$45 million Term loan, due 2011	**–**	33
Exploits Partnership		
7.55% $65 million Term loan, due 2028	**62**	63
Walden Power Partnership		
9.44% $10 million WPP Mortgage, due 2013	**5**	6
	67	102

(in millions)	2007	2006
Non-Regulated – Fortis Properties		
Secured:		
6.42% $15 million First mortgage, due 2007	**–**	4
6.85% $5 million First mortgage, due 2007	**–**	5
5.10% $30 million First mortgage, due 2010	**27**	28
5.35% $12 million First mortgage, due 2010	**11**	12
8.15% $21 million First mortgage, due 2010	**15**	15
9.47% $13 million First mortgage, due 2010	**10**	11
7.42% $29 million First mortgage, due 2012	**25**	25
7.77% $23 million First mortgage, due 2012	**20**	21
6.58% $35 million First mortgage, due 2013	**30**	31
7.30% $30 million First mortgage, due 2013	**27**	28
6.42% $16 million First mortgage, due 2014	**15**	15
7.50% $50 million First mortgage, due 2017	**40**	41
7.32% $22 million Senior notes, due 2019	**17**	18
Obligation under capital leases, due 2008 and 2012	**2**	3
Non-revolving credit facilities, due 2009 to 2010	**7**	8
	246	265
Corporate and Other		
Fortis Inc.		
7.40% $100 million Senior Unsecured Debentures, due 2010	**100**	100
6.75% US$10 million Unsecured Subordinated Convertible Debentures, due 2012 (December 31, 2007 – US$6 million)	**6**	11
5.50% US$10 million Unsecured Subordinated Convertible Debentures, due 2013 (December 31, 2007 – US$4 million)	**4**	11
5.74% US$150 million Senior Unsecured Notes, due 2014 (December 31, 2007 – US$150 million)	**149**	175
5.50% US$40 million Unsecured Subordinated Convertible Debentures, due 2016 (December 31, 2007 – US$40 million)	**35**	41
6.60% US$200 million Senior Unsecured Notes, due 2037 (December 31, 2007 – US$200 million)	**198**	–
	492	338
Terasen Inc.		
6.30% $200 million Unsecured Debentures, due 2008	**203**	–
5.56% $125 million Unsecured Debentures, due 2014	**133**	–
8.00% $125 million Capital Securities, due 2040	**126**	–
	462	–
Long-term classification of credit facilities *(Note 9)*	**530**	235
Total long-term debt and capital lease obligations	**5,092**	2,643
Deferred financing costs	**(33)**	–
Less: Current installments of long-term debt and capital lease obligations	**(436)**	(85)
	$ 4,623	$ 2,558

December 31, 2007 and 2006

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

Regulated Utilities

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

On October 2, 2007, TGI issued $250 million 6.00% medium-term note debentures. The debentures mature on October 2, 2037 and are unsecured. The proceeds were used to repay Series 13 and Series 20 medium-term note debentures of TGI, which matured in 2007.

With the exception of the $250 million 6.00% debentures, the purchase money mortgages and unsecured debentures were assumed by Fortis upon acquisition of the Terasen Gas companies.

FortisAlberta
On January 3, 2007, FortisAlberta issued a $110 million 4.99% senior unsecured debenture offering, maturing on January 3, 2047.

FortisBC
The secured Series E, F and G debentures are collaterized by a fixed and floating first charge on the assets of FortisBC. Sinking fund payments of $0.75 million per year are required for the Series E debentures.

On July 4, 2007, FortisBC issued $105 million 5.90% senior unsecured debentures, maturing on July 4, 2047.

FortisBC has a capital lease obligation with respect to the BTS (Note 4 *(xii)*). Future minimum lease payments associated with this capital lease obligation are approximately $3 million per year over the remaining term of the lease agreement to 2032. The BTS lease obligation bears interest at a composite rate of 8.62 per cent.

Newfoundland Power and Maritime Electric
The Newfoundland Power and Maritime Electric first mortgage bonds are secured by a first fixed and specific charge on the respective utility's capital assets owned or to be acquired and by a floating charge on all other assets.

On August 17, 2007, Newfoundland Power issued $70 million 5.901% first mortgage sinking fund bonds, maturing on August 17, 2037.

Belize Electricity
The RBTT Merchant Bank loan is secured by a debenture over specific assets of the Company.

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

The IBRD loan bears interest at 0.50 per cent per annum above the bank's "Cost of Qualified Borrowings" as defined in the loan agreement. The effective rate of interest as of December 31, 2007 was 6.89 per cent per annum (December 31, 2006 – 5.35 per cent). The Bank of Nova Scotia loan bears interest at the prevailing six-month London Interbank Offered Rate ("LIBOR") plus 0.50 per cent per annum. The Scotiabank & Trust (Cayman) Limited loan bears interest at the prevailing six-month LIBOR plus 5.00 per cent per annum.

Caribbean Utilities
During 2007, Caribbean Utilities issued a US$40 million private placement of 5.65% senior unsecured notes due June 1, 2022.

Fortis Turks and Caicos
The Scotiabank (Turks and Caicos) Ltd. debt consists of three loans, bearing interest at a floating rate of 1.00 per cent above LIBOR, a fixed rate of 6.04 per cent per annum and a fixed rate of 6.10 per cent per annum.

Fortis Generation

BECOL
On November 28, 2007, BECOL repaid early the remaining amount on its original US$45 million term loan. The loan bore interest at the prevailing six-month LIBOR plus 4.00 per cent and was secured by agreements covering all its property assets and undertakings.

Exploits Partnership
A first, fixed and specific charge and security interest over all the assets of the Exploits Partnership and assignment of various agreements has been provided as security on the Exploits Partnership non-recourse 25-year amortizing term loan.

Walden Power Partnership
The WPP mortgage is collateralized by a fixed and floating charge over the assets of the WPP.

Fortis Properties

Fortis Properties' first mortgages are collateralized by a fixed and floating charge on specific income producing properties. The senior secured notes are collateralized by a fixed and specific mortgage and a charge on a specific income producing property.

The non-revolving credit facilities at Fortis Properties, bearing interest at Canadian Bankers' Acceptance rates, are collateralized by specific income producing properties. Fortis Properties is party to two interest rate swap contracts maturing on July 28, 2009 and October 15, 2010, respectively, to hedge against interest exposures on the non-revolving credit facilities. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities at 5.32 per cent and 6.16 per cent, respectively.

Corporate and Other

Fortis Inc.
The 7.40% senior unsecured debentures are redeemable at the option of the Corporation at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Canada Yield, plus a premium ranging from 0.43 per cent to 0.87 per cent, together with accrued and unpaid interest thereon.

The 6.75% unsecured subordinated convertible debentures are redeemable by the Corporation at par at any time on or after March 12, 2007, and are convertible, at the option of the holder, into the Corporation's Common Shares at $9.11 per share (US$9.19 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The 5.50% unsecured subordinated convertible debentures, due 2013, are redeemable by the Corporation at par at any time on or after May 20, 2008, and are convertible, at the option of the holder, into the Corporation's Common Shares at $11.87 per share (US$11.97 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The 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 $28.86 per share (US$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $6 million at December 31, 2007 (December 31, 2006 – $7 million).

On September 6, 2007, the Corporation issued US$200 million 6.60% senior unsecured notes, maturing on September 1, 2037.

Terasen Inc.
The 8.00% capital securities were issued on April 19, 2000. Terasen Inc. may elect to defer payment on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. The Company has the right to redeem the securities at the principal amount, together with accrued and unpaid interest, on or after April 19, 2010. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash.

The unsecured debentures and capital securities were assumed by Fortis upon acquisition of Terasen Inc.

December 31, 2007 and 2006

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

Deferred Financing Costs

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of $21 million as at January 1, 2007 relating to long-term debt were reclassified from deferred charges and other assets to long-term debt and, effective January 1, 2007, any deferred financing costs associated with new debt issuances are now recorded against the debt balances. The deferred financing costs are amortized into earnings using the effective interest rate method over the life of the related debt.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years are as follows:

2008	$ 436 million
2009	$ 191 million
2010	$ 215 million
2011	$ 307 million
2012	$ 321 million

11. Deferred Credits

(in millions)	**2007**	2006
OPEB obligations *(Note 20)*	**$ 112**	$ 51
Supplementary defined benefit obligations *(Note 20)*	**38**	12
Deferred gains on sale of natural gas transmission and distribution assets	**50**	–
Deferred payment	**40**	–
Customer deposits	**5**	5
Deferred gain on forward currency swap agreement	**–**	3
Trail lease costs *(Note 4 (xii))*	**2**	2
Other deferred credits	**14**	6
	$ 261	$ 79

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 25.

The deferred payment resulted from Terasen Inc.'s acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of $52 million but was discounted at May 17, 2007 to its present value. At December 31, 2007, its present value was $40 million. The payment is due on December 31, 2011 or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants which may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

As of January 1, 2007, in accordance with the transitional provision of Section 3865, *Hedges*, an unamortized deferred gain balance of $3 million, related to a previously cancelled forward currency swap agreement, was reclassified from deferred credits to accumulated other comprehensive loss (Note 16).

12. Non-Controlling Interest

(in millions)	**2007**	2006
Caribbean Utilities	**$ 67**	$ 78
Belize Electricity	**38**	42
Exploits Partnership	**3**	3
Preference shares of Newfoundland Power	**7**	7
	$ 115	$ 130

13. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2007**		2006	
	Classification	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
(i) First Preference Shares, Series C	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
(ii) First Preference Shares, Series E	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt		**12,993,500**	**$ 320**	12,993,500	$ 320
(iii) First Preference Shares, Series F	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122

(i) First Preference Shares, Series C

The 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 at such time.

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 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 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.

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

(ii) First Preference Shares, Series E

The First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends in the amount 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.

December 31, 2007 and 2006

13. *Preference Shares (cont'd)*

(ii) First Preference Shares, Series E (cont'd)

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, Series E for cash or arrange for the sale of those shares to other purchasers.

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

(iii) First Preference Shares, Series F

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of $1.2250 per share per annum.

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.

As the First Preference Shares, Series F are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the statement of earnings immediately before arriving at net earnings applicable to common shares.

14. Common Shares

Authorized: an unlimited number of Common Shares without nominal or par value.

Issued and Outstanding	**2007**		2006	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Common Shares	**155,521,313**	**$ 2,126**	104,091,542	$ 829

Common Shares issued during the year were as follows:

	2007		2006	
	Number of Shares	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Opening balance	**104,091,542**	**$ 829**	103,203,981	$ 813
Public offering	**5,170,000**	**146**	–	–
Public offering – Conversion of Subscription Receipts	**44,275,000**	**1,119**	–	–
Conversion of debentures	**882,626**	**9**	–	–
Consumer Share Purchase Plan	**79,463**	**3**	77,213	2
Dividend Reinvestment Plan	**203,763**	**5**	176,264	5
Employee Share Purchase Plan	**240,578**	**6**	135,502	3
Stock Option Plans	**578,341**	**9**	498,582	6
Ending balance	**155,521,313**	**$ 2,126**	104,091,542	$ 829

On January 18, 2007, Fortis issued 5,170,000 Common Shares for $29.00 per common share. The common share issuance resulted in gross proceeds of approximately $150 million, or approximately $146 million net of after-tax expenses.

During 2007, holders of the Corporation's 6.75% unsecured subordinated convertible debentures converted US$4 million of the US$10 million debentures into 435,490 Common Shares of the Corporation.

During 2007, holders of the Corporation's 5.50% unsecured subordinated convertible debentures converted approximately US$5 million of the US$10 million debentures into 447,136 Common Shares of the Corporation.

On March 15, 2007, to finance a significant portion of the net cash purchase price of Terasen, the Corporation sold 44,275,000 Subscription Receipts at $26.00 each, for gross proceeds of approximately $1.15 billion. Upon closing of the acquisition of Terasen on May 17, 2007, each Subscription Receipt was exchanged, without payment of additional consideration, for one Common Share of Fortis. Each Subscription Receipt holder also received a cash payment of $0.21 per Subscription Receipt, which was an amount equal to the dividend declared per Common Share of Fortis to holders of record as of May 4, 2007. The net proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $1.12 billion, net of after-tax expenses.

At December 31, 2007, 9.9 million Common Shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans.

At December 31, 2007, Common Shares reserved for issuance under the terms of the Corporation's convertible debentures and Preference Shares were 2.4 million and 26 million, respectively.

As at December 31, 2007, $3 million (December 31, 2006 – $1 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 137.6 million and 103.6 million at December 31, 2007 and December 31, 2006, respectively.

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

Earnings per common share are as follows:

	2007			2006		
	Earnings *(in millions)*	**Weighted Average Shares** *(in millions)*	**Earnings per Common Share**	Earnings *(in millions)*	Weighted Average Shares *(in millions)*	Earnings per Common Share
Net earnings applicable to common shares	**$ 193**			$ 147		
Weighted average shares outstanding		**137.6**			103.6	
Basic Earnings per Common Share			**$ 1.40**			$ 1.42
Effect of potential dilutive securities:						
Subscription receipts[1]	**–**	**7.8**		–	–	
Stock options	**–**	**1.2**		–	1.2	
Preference shares						
(Notes 13 (i) and (ii) and 17)	**16**	**11.5**		17	14.1	
Convertible debentures	**3**	**2.8**		1	2.0	
	212	**160.9**		165	120.9	
Deduct anti-dilutive impacts:						
Convertible debentures	**(2)**	**(1.4)**		–	–	
Diluted Earnings per Common Share	**$ 210**	**159.5**	**$ 1.32**	$ 165	120.9	$ 1.37

(1) Dilution relating to the period the Subscription Receipts were outstanding from March 15, 2007 to May 16, 2007, prior to their conversion into Common Shares.

15. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis Inc. and its subsidiaries options to purchase Common Shares of the Corporation. At December 31, 2007, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted by Fortis Inc. under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years, which is reduced from ten years under the 2002 Plan, and expire no later than three years after the termination, death or retirement of the optionee. Directors are not eligible to receive grants of options under the 2006 Plan. During 2006, the Corporation replaced the equity component of directors' annual compensation with DSUs.

Number of Options:	**2007**	2006
Options outstanding, beginning of year	**3,550,055**	3,421,876
Granted	**754,800**	626,761
Cancelled	**(34,743)**	–
Exercised	**(578,341)**	(498,582)
Options outstanding, end of year	**3,691,771**	3,550,055
Options vested, end of year	**1,901,811**	1,739,759

Weighted Average Exercise Prices:	**2007**	2006
Options outstanding, beginning of year	**$ 16.11**	$ 14.18
Granted	**27.75**	22.94
Cancelled	**22.43**	–
Exercised	**13.35**	11.45
Options outstanding, end of year	**18.86**	16.11

Details of stock options outstanding and vested as at December 31, 2007 are as follows:

Outstanding			**Vested**		
Number of Options	**Exercise Price**	**Expiry Date**	**Number of Options**	**Exercise Price**	**Expiry Date**
112,422	$ 9.57	2011	112,422	$ 9.57	2011
302,076	$ 12.03	2012	302,076	$ 12.03	2012
527,675	$ 12.81	2013	527,675	$ 12.81	2013
626,382	$ 15.28	2014	457,450	$ 15.28	2014
12,000	$ 15.23	2014	7,000	$ 15.23	2014
33,910	$ 14.55	2014	19,262	$ 14.55	2014
683,742	$ 18.40	2015	316,422	$ 18.40	2015
28,000	$ 18.11	2015	14,000	$ 18.11	2015
31,639	$ 20.82	2015	14,769	$ 20.82	2015
590,621	$ 22.94	2016	130,735	$ 22.94	2016
606,472	$ 28.19	2014	1,901,811		
136,832	$ 25.76	2014			
3,691,771					

The weighted average exercise price of stock options vested as at December 31, 2007 was $14.84.

On May 7, 2007, the Corporation granted 617,968 options on common shares under its 2006 Plan at the five-day volume weighted average trading price immediately preceding the date of grant of $28.19. These options vest evenly over a four-year period on each anniversary of the date of grant. The options expire seven years after the date of grant. The fair market value of each option granted was $4.40 per option.

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

	May 7, 2007
Dividend yield *(%)*	3.06
Expected volatility *(%)*	18.9
Risk-free interest rate *(%)*	4.18
Weighted average expected life *(years)*	4.5

On August 16, 2007, the Corporation granted 136,832 options on common shares under its 2006 Plan at the five-day volume weighted average trading price immediately preceding the date of grant of $25.76. These options vest evenly over a four-year period on each anniversary of the date of grant. The options expire seven years after the date of grant. The fair market value of each option granted was $4.25 per option.

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

	August 16, 2007
Dividend yield *(%)*	3.06
Expected volatility *(%)*	19.6
Risk-free interest rate *(%)*	4.43
Weighted average expected life *(years)*	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $2 million for the year ended December 31, 2007 (2006 – $2 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit of their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective during 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Number of DSUs:	**2007**	2006
DSUs outstanding, beginning of year	**46,959**	24,986
Granted	**20,859**	22,101
Granted – notional dividends reinvested	**1,904**	1,198
DSUs paid out	**–**	(1,326)
DSUs outstanding, end of year	**69,722**	46,959

For the year ended December 31, 2007, expenses of $0.8 million (2006 – $0.8 million) were recorded in relation to the DSU Plan.

December 31, 2007 and 2006

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

RSU Plan

In 2004, the Corporation introduced the RSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each RSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation.

Number of RSUs:	2007	2006
RSUs outstanding, beginning of year	**66,845**	36,855
Granted	**19,570**	28,400
Granted – notional dividends reinvested	**1,883**	1,590
RSUs paid out	**(20,683)**	–
RSUs outstanding, end of year	**67,615**	66,845

In May 2007, RSUs paid out to the President and CEO were 20,683 at $28.01 per RSU, for a total of approximately $0.6 million. The payout was made upon the three-year maturation period in respect of the RSU grant which was made on May 11, 2004, and the President and CEO satisfying the payment criteria.

For the year ended December 31, 2007, expenses of $0.6 million (2006 – $0.7 million) were recorded in relation to the RSU Plan.

16. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2007			
(in millions)	Opening balance January 1	Transition amount January 1	Net change	**Ending balance December 31**
Unrealized foreign currency translation losses, net of hedging activities	**$ (51)**	**$ –**	**$ (31)**	**$ (82)**
Losses on derivative instruments designated as cash flow hedges, net of tax	**–**	**(1)**	**–**	**(1)**
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**–**	**(5)**	**–**	**(5)**
Accumulated other comprehensive loss	**$ (51)**	**$ (6)**	**$ (31)**	**$ (88)**

	2006		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities	$ (16)	$ (35)	$ (51)
Accumulated other comprehensive loss	$ (16)	$ (35)	$ (51)

As required, prior periods have not been restated as a result of implementing Section 1530, *Comprehensive Income*, except to reclassify unrealized foreign currency translation losses on net investments in self-sustaining foreign operations, net of hedging activities, of $51 million as at January 1, 2007 from the foreign currency translation adjustment account in shareholders' equity to accumulated other comprehensive loss. As required upon initial application of Section 3855, *Financial Instruments – Recognition and Measurement*, all adjustments to the carrying amount of financial instruments were recognized as an adjustment to the opening balance of accumulated other comprehensive loss. The Corporation was not required to remeasure any assets or liabilities upon adoption of Section 3855; therefore, no adjustments were made to the opening balance of retained earnings.

During 2007, unrealized foreign currency translation losses of $70 million (2006 – gains of $9 million) were recorded in other comprehensive loss related to the Corporation's net investment in US dollar-denominated self-sustaining foreign operations. These unrealized foreign currency translation losses were partially offset by the effective portion of unrealized after-tax gains of $39 million (2006 – after-tax losses of $5 million) related to the translation of US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

On November 7, 2006, the Corporation, through a wholly owned subsidiary, acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now holds an approximate 54 per cent controlling interest in the Company. As a result of this acquisition, a foreign currency translation loss of $39 million was reflected in accumulated other comprehensive loss, representing the impact of the appreciation of the Canadian dollar relative to the US dollar between the original share purchase dates and the recording of the net investment in Caribbean Utilities as a self-sustaining foreign operation, effective November 7, 2006.

During 2007, unrealized losses of an immaterial amount were recorded in other comprehensive loss for the effective portion of the change in fair value of the interest rate swap agreements at Fortis Properties and BECOL designated as cash flow hedges, with the offset recorded to deferred credits on the balance sheet. There were no ineffective portions. The amounts recognized are reclassified to finance charges in the periods during which the variability of cash flows of the hedged items affect finance charges. The net loss reclassified to earnings during 2007 was immaterial. In November 2007, BECOL cancelled its interest rate swap agreement upon the early repayment of the related debt.

As at January 1, 2007, in accordance with the transitional provisions of Section 3865, *Hedges*, a net loss of $5 million associated with unamortized deferred gain and loss balances related to previously cancelled swap agreements were reclassified to accumulated other comprehensive loss. An unamortized loss balance of $11 million ($7 million after-tax), as at January 1, 2007, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets (Note 5) and an unamortized gain balance of $3 million ($2 million after-tax), as at January 1, 2007, related to a previously cancelled US dollar forward currency swap agreement was reclassified from deferred credits (Note 11). The deferred gain and loss balances are amortized to comprehensive income (loss) on a straight-line basis over the life of the related debt.

17. Finance Charges

(in millions)	**2007**	2006
Interest – Long-term debt and capital lease obligations	**$ 266**	$ 155
– Short-term borrowings	**27**	6
Interest charged to construction *(Note 2)*	**(8)**	(4)
Interest earned	**(4)**	(4)
Unrealized foreign exchange loss (gain) on long-term debt	**1**	(2)
Dividends on preference shares *(Notes 13 (i) and (ii) and 14)*	**17**	17
	$ 299	$ 168

Interest on long-term debt, short-term borrowings and dividends associated with preference shares have been calculated using the effective interest rate method, effective January 1, 2007, in accordance with the adoption of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*.

December 31, 2007 and 2006

18. Gain on Sale of Property

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

In June 2006, Fortis Properties sold the Days Inn Sydney resulting in a $2 million ($1.6 million after-tax) gain on sale.

19. Corporate Taxes

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted Canadian federal and provincial statutory tax rates to earnings before corporate taxes. The following is a reconciliation of the consolidated statutory tax rate to the consolidated effective tax rate:

(%)	**2007**	2006
Statutory tax rate	**35.1**	35.2
Preference share dividends	**2.4**	3.2
Difference between Canadian statutory rates and those applicable to foreign subsidiaries	**(7.1)**	(6.8)
Items capitalized for accounting but expensed for income tax purposes	**(8.3)**	(10.7)
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	**(4.8)**	(1.2)
Impact of reduction in income tax rates on future income taxes	**(2.4)**	(2.4)
Regulatory deferrals at Newfoundland Power	**(1.0)**	–
TGI tax reassessment	**0.9**	–
Maritime Electric tax reassessment	**1.0**	0.9
Pension costs	**(0.7)**	(0.4)
Other	**(0.7)**	(0.9)
Effective tax rate	**14.4**	16.9

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

(in millions)	**2007**	2006
Canadian		
Current taxes	**$ 33**	$ 20
Future income taxes	**–**	9
	33	29
Foreign		
Current taxes	**3**	2
Future income taxes	**–**	1
	3	3
Corporate tax expense	**$ 36**	$ 32

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

(in millions)	**2007**	2006
Future income tax liability (asset)		
Utility capital assets and income producing properties	**$ 35**	$ 46
ECAM	**10**	5
Other regulatory assets and liabilities	**2**	11
Intangible assets	**2**	3
Tenant inducements	**3**	2
Employee future benefits	**(14)**	(9)
Losses carried forward	**(10)**	(8)
Share issue and debt financing costs	**(16)**	(1)
Unrealized foreign currency translation gains on long-term debt	**8**	2
Other	**5**	1
Net future income tax liability	**$ 25**	$ 52
Current future income tax liability	**$ 7**	$ 1
Long-term future income tax asset	**(37)**	(7)
Long-term future income tax liability	**55**	58
Net future income tax liability	**$ 25**	$ 52

As at December 31, 2007, the Corporation had approximately $49 million (2006 – $24 million) in non-capital and capital losses carried forward, of which $0.2 million (2006 – $0.3 million) in capital losses has not been recognized in the financial statements. The non-capital loss carry forwards expire between 2008 and 2027.

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, Terasen, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension arrangements, the accrued benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31st of each year for the Corporation, Terasen and Newfoundland Power; as at September 30th of each year for FortisAlberta, FortisBC and FortisOntario; and as at April 30th of each year for Caribbean Utilities. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2006 for FortisOntario; as of December 31, 2005 for the Corporation and Newfoundland Power; as of December 31, 2004 for FortisAlberta and FortisBC; and as of April 30, 2006 for Caribbean Utilities. For Terasen, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2004 and December 31, 2006. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company and those required as at December 31, 2007 are expected to be completed during 2008.

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

Plan assets as at December 31st

(%)	**2007**	2006
Canadian equities	**50**	45
Fixed income	**38**	39
Foreign equities	**8**	15
Real estate	**4**	1
	100	100

December 31, 2007 and 2006

20. Employee Future Benefits (cont'd)

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

	2007			2006		
(in millions)	**Accrued Benefit Obligation**	**Plan Assets**	**Net Funded (Unfunded)**	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen	**$ 254**	**$ 261**	**$ 7**	$ –	$ –	$ –
FortisAlberta	**23**	**20**	**(3)**	21	18	(3)
FortisBC	**122**	**105**	**(17)**	118	95	(23)
Newfoundland Power	**236**	**260**	**24**	239	250	11
FortisOntario	**23**	**21**	**(2)**	25	21	(4)
Caribbean Utilities	**5**	**3**	**(2)**	6	3	(3)
Fortis Inc.	**4**	**4**	**–**	4	3	(1)
Total	**$ 667**	**$ 674**	**$ 7**	$ 413	$ 390	$ (23)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	**2007**	2006	**2007**	2006	**2007**	2006
Change in accrued benefit obligation						
Balance, beginning of year	**$ 413**	$ 390	**$ 17**	$ 14	**$ 109**	$ 103
Liability associated with acquisitions	**248**	6	**27**	–	**79**	–
Current service costs	**12**	7	**1**	1	**4**	3
Employee contributions	**6**	3	**–**	–	**–**	–
Interest costs	**29**	20	**2**	1	**8**	5
Benefits paid	**(25)**	(19)	**(2)**	–	**(4)**	(4)
Actuarial (gain) loss	**(16)**	2	**(1)**	–	**(8)**	2
Plan amendments	**–**	4	**–**	1	**1**	–
Balance, end of year	**$ 667**	$ 413	**$ 44**	$ 17	**$ 189**	$ 109
Change in value of plan assets						
Balance, beginning of year	**$ 390**	$ 350	**$ –**	$ –	**$ –**	$ –
Assets associated with acquisitions	**256**	3	**–**	–	**–**	–
Actual return on plan assets	**26**	35	**–**	–	**–**	–
Benefits paid	**(25)**	(19)	**(2)**	–	**(4)**	(4)
Employee contributions	**6**	3	**–**	–	**–**	–
Employer contributions	**21**	18	**2**	–	**4**	4
Balance, end of year	**$ 674**	$ 390	**$ –**	$ –	**$ –**	$ –
Funded status						
Surplus (deficit), end of year	**$ 7**	$ (23)	**$ (44)**	$ (17)	**$ (189)**	$ (109)
Unamortized net actuarial loss	**95**	85	**3**	3	**61**	39
Unamortized past service costs	**10**	9	**1**	1	**(2)**	–
Unamortized transitional obligation	**7**	21	**2**	1	**18**	19
Employer contributions after measurement date	**1**	1	**–**	–	**–**	–
Accrued benefit asset (liability), end of year *(Notes 5 and 11)*	**$ 120**	$ 93	**$ (38)**	$ (12)	**$ (112)**	$ (51)

(in millions)	Defined Benefit Pension Plans Funded 2007	2006	Supplementary Defined Benefit Plans Unfunded 2007	2006	OPEB Plans Unfunded 2007	2006
Significant assumptions						
Discount rate during year *(%)*	**5.00–5.25**	5.00–5.25	**5.00–5.25**	5.00–5.25	**5.00–5.25**	5.00–5.25
Discount rate as at December 31st *(%)*	**5.25–5.60**	5.00–5.25	**5.25–5.75**	5.25	**5.25–5.75**	5.00–5.25
Expected long-term rate of return on plan assets *(%)*	**6.50–7.50**	6.50–7.50	**–**	–	**–**	–
Rate of compensation increase *(%)*	**3.50–4.25**	3.50–4.00	**3.77–4.25**	3.50–4.00	**3.50–4.25**	3.50–4.00
Health care cost trend increase as at December 31st *(%)*	**–**	–	**–**	–	**4.50–10.00**	4.50–10.00
Expected average remaining service life of active employees *(years)*	**7–13**	7–15	**3–13**	3–15	**10–16**	11–17
Components of net benefit expense						
Current service costs	**$ 12**	$ 7	**$ 1**	$ 1	**$ 4**	$ 3
Interest costs	**29**	20	**2**	1	**8**	5
Actual return on plan assets	**(26)**	(35)	**–**	–	**–**	–
Actuarial (gain) loss	**(16)**	2	**(1)**	–	**(8)**	2
Plan amendments	**–**	–	**–**	–	**1**	–
Costs arising in the year	**(1)**	(6)	**2**	2	**5**	10
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	**(11)**	11	**–**	–	**–**	–
Actuarial gain	**20**	4	**1**	–	**11**	–
Past service costs	**3**	2	**–**	1	**–**	–
Special termination benefits	**1**	–	**–**	–	**–**	–
Transitional obligation and amendments	**1**	2	**–**	–	**2**	2
Regulatory adjustment	**(1)**	(2)	**–**	(1)	**(7)**	(5)
Net benefit expense	**$ 12**	$ 11	**$ 3**	$ 2	**$ 11**	$ 7

For 2007, the effects of changing the health-care cost trend rate by a 1 per cent increase and a 1 per cent decrease are as follows:

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 28**	**$ (23)**
Increase (decrease) in service and interest costs	**$ 2**	**$ (2)**

During 2007, the Corporation expensed $10 million (2006 – $8 million) related to defined contribution pension plans.

21. Business Acquisitions

2007

a. Terasen

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

December 31, 2007 and 2006

21. Business Acquisitions (cont'd)

2007 (cont'd)

a. Terasen (cont'd)

Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies. Terasen is the principal natural gas distributor in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province.

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, and Terasen's 30 per cent investment in non-regulated CWLP have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The determination of revenue and earnings is based on regulated rates of return that are applied to historic values which do not change with a change of ownership. Therefore, for substantially all of the individual assets and liabilities associated with the Terasen Gas companies, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation related to non-regulated Terasen and its non-regulated investments.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to finalization, with adjustments, if any, to be completed during the second quarter of 2008. The amount of the purchase price assignable to goodwill is entirely associated with the regulated Terasen Gas companies. Approximately $40 million of goodwill is deductible for tax purposes. Of the $11 million in intangible assets, $10 million was assigned as the value associated with customer contracts at CWLP. Approximately $1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

(in millions)	**Total**
Fair value assigned to net assets:	
Utility capital assets	**$ 2,768**
Current assets	**355**
Goodwill	**907**
Intangibles	**11**
Long-term regulatory assets	**69**
Other assets	**42**
Current liabilities	**(353)**
Assumed short-term indebtedness	**(275)**
Assumed long-term debt (including current portion)	**(2,077)**
Long-term regulatory liabilities	**(29)**
Other liabilities	**(165)**
	1,253
Cash	**3**
	$ 1,256

b. Delta Regina

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina Hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan for an aggregate cash purchase price of approximately $50 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing August 1, 2007.

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

(in millions)	Total
Fair value assigned to net assets:	
Income producing properties	**$ 50**

2006

a. Caribbean Utilities

On November 7, 2006, Fortis, through a wholly owned subsidiary, acquired an aggregate of 4,113,116 of the outstanding Class A Ordinary Shares of Caribbean Utilities for US$11.89 per share under a private agreement with International Power Holdings Ltd. ("IPHL") and four other vendors affiliated with IPHL. The aggregate purchase price of $56 million (US$49 million), including acquisition costs, was financed through cash consideration from the issuance of US$40 million unsecured subordinated convertible debentures, combined with drawings on the Corporation's credit facilities.

Following this acquisition, Fortis controls Caribbean Utilities by beneficially owning 13,565,511, or approximately 54 per cent, of the outstanding Class A Ordinary Shares of Caribbean Utilities.

The acquisition has been accounted for using the purchase method. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities' October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation's December 31, 2007 Consolidated Financial Statements. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, accounted for on an equity basis, on a two-month lag. Caribbean Utilities' financial results are reported in the Corporation's Regulated Electric Utilities – Caribbean segment.

The determination of revenues and earnings of Caribbean Utilities is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximates fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The Corporation has accounted for the acquisition of the controlling interest in Caribbean Utilities as a two-step acquisition for the purpose of purchase price allocation and the assigning of costs to identifiable assets, goodwill and intangible assets, if any.

The total purchase price allocation was as follows:

(in millions)	
Fair value assigned to net assets:	
Utility capital assets	$ 318
Current assets	30
Goodwill	106
Regulatory assets	13
Other assets	2
Current liabilities	(29)
Assumed long-term debt (including current portion)	(178)
Non-controlling interest	(77)
	185
Cash	3
	$ 188

December 31, 2007 and 2006

21. Business Acquisitions (cont'd)

2006 (cont'd)

b. Fortis Turks and Caicos

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all of the issued and outstanding common shares of PPC and Atlantic (collectively referred to as Fortis Turks and Caicos) for aggregate consideration of approximately $98 million (US$88 million). The purchase price, net of assumed debt and acquisition costs, of $76 million (US$68 million) was initially financed, through cash consideration, by way of drawings on the Corporation's credit facilities that were repaid, in part, with partial proceeds from the issuance of First Preference Shares, Series F of Fortis on September 28, 2006.

The acquisition has been accounted for using the purchase method, whereby the results of operations of Fortis Turks and Caicos have been included in the consolidated financial statements of Fortis in the Regulated Electric Utilities – Caribbean segment, commencing August 28, 2006. The determination of revenues and earnings of Fortis Turks and Caicos is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximates fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The purchase price allocation was as follows:

(in millions)	PPC	Atlantic	Total
Fair value assigned to net assets:			
Utility capital assets	$ 45	$ 1	$ 46
Current assets	18	1	19
Goodwill	39	–	39
Other assets	1	–	1
Current liabilities	(3)	–	(3)
Assumed long-term debt (including current portion)	(22)	–	(22)
Other liabilities	(2)	(2)	(4)
	$ 76	$ –	$ 76

c. Hotels

On November 1, 2006, Fortis Properties purchased assets comprising four hotels in Alberta and British Columbia for an aggregate cash purchase price of approximately $52 million, including assumed debt and acquisition costs. The four hotels were the Holiday Inn Express and Suites, and Best Western, in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia.

The acquisition has been accounted for using the purchase method, whereby the results of operations of the hotels have been included in the consolidated financial statements of Fortis from the date of acquisition, commencing November 1, 2006.

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

(in millions)	
Fair value assigned to net assets:	
Income producing properties	$ 52
Assumed long-term debt (including current portion)	(12)
	$ 40

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2007 *(in millions)*	**Terasen Gas Companies – Canadian**(1)	Fortis Alberta	Fortis BC	NF Power	Other Canadian(2)	**Total Electric Canadian**	**Electric Caribbean**(3)	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Operating revenues	**905**	270	229	490	263	**1,252**	**307**	**75**	**191**	**22**	**(34)**	**2,718**
Energy supply costs	**559**	–	67	327	174	**568**	**169**	**8**	**–**	**–**	**(17)**	**1,287**
Operating expenses	**150**	122	69	53	29	**273**	**49**	**14**	**123**	**13**	**(5)**	**617**
Amortization	**58**	75	31	34	17	**157**	**28**	**10**	**14**	**6**	**–**	**273**
Operating income	**138**	73	62	76	43	**254**	**61**	**43**	**54**	**3**	**(12)**	**541**
Finance charges	**80**	36	26	33	17	**112**	**15**	**10**	**24**	**70**	**(12)**	**299**
Gain on sale of property	**(8)**	–	–	–	–	**–**	**–**	**–**	**–**	**–**	**–**	**(8)**
Corporate taxes (recovery)	**16**	(11)	5	12	10	**16**	**2**	**8**	**6**	**(12)**	**–**	**36**
Non-controlling interest	**–**	–	–	1	–	**1**	**13**	**1**	**–**	**–**	**–**	**15**
Net earnings (loss)	**50**	48	31	30	16	**125**	**31**	**24**	**24**	**(55)**	**–**	**199**
Preference share dividends	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**6**	**–**	**6**
Net earnings (loss) applicable to common shares	**50**	48	31	30	16	**125**	**31**	**24**	**24**	**(61)**	**–**	**193**
Goodwill	**907**	227	221	–	63	**511**	**126**	**–**	**–**	**–**	**–**	**1,544**
Identifiable assets	**3,540**	1,294	914	986	484	**3,678**	**652**	**235**	**535**	**108**	**(19)**	**8,729**
Total assets	**4,447**	1,521	1,135	986	547	**4,189**	**778**	**235**	**535**	**108**	**(19)**	**10,273**
Gross capital expenditures	**120**	285	147	72	38	**542**	**106**	**17**	**13**	**5**	**–**	**803**
Year ended December 31, 2006												
Operating revenues	–	251	216	421	252	1,140	101	80	163	9	(31)	1,462
Equity income	–	–	–	–	–	–	10	–	–	–	–	10
Energy supply costs	–	–	68	256	171	495	57	6	–	–	(18)	540
Operating expenses	–	115	63	54	28	260	13	15	105	11	(5)	399
Amortization	–	69	28	33	15	145	7	11	12	3	–	178
Operating income	–	67	57	78	38	240	34	48	46	(5)	(8)	355
Finance charges	–	30	23	33	15	101	5	10	21	39	(8)	168
Gain on sale of property	–	–	–	–	–	–	–	–	(2)	–	–	(2)
Corporate taxes (recovery)	–	(5)	7	14	9	25	2	8	8	(11)	–	32
Non-controlling interest	–	–	–	1	–	1	4	3	–	–	–	8
Net earnings (loss)	–	42	27	30	14	113	23	27	19	(33)	–	149
Preference share dividends	–	–	–	–	–	–	–	–	–	2	–	2
Net earnings (loss) applicable to common shares	–	42	27	30	14	113	23	27	19	(35)	–	147
Goodwill	–	228	221	–	63	512	149	–	–	–	–	661
Identifiable assets	–	1,158	810	929	447	3,344	679	246	486	43	(18)	4,780
Total assets	–	1,386	1,031	929	510	3,856	828	246	486	43	(18)	5,441
Gross capital expenditures	–	243	111	60	37	451	27	3	17	2	–	500

(1) Terasen was acquired on May 17, 2007.
(2) Includes Maritime Electric and FortisOntario
(3) Includes Belize Electricity, Fortis Turks and Caicos, acquired on August 28, 2006, and Caribbean Utilities on Grand Cayman, Cayman Islands

The Corporation has changed the reporting of its operating segments whereby the financial results of Maritime Electric and FortisOntario have now been aggregated into one reportable segment and presented as "Regulated Electric Utilities – Other Canadian". Comparative segmented information has been restated to reflect this change in reporting.

December 31, 2007 and 2006

22. Segmented Information (cont'd)

During 2007, the Corporation began reporting a new segment "Regulated Gas Utilities – Canadian" which includes the financial results of the regulated gas distribution business of Terasen, the principal natural gas distributor in British Columbia, acquired by the Corporation on May 17, 2007. Additionally, net expenses of non-regulated Terasen corporate-related activities, and Terasen's 30 per cent ownership interest in CWLP, have been included in the Corporate and Other segment from May 17, 2007.

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31st were as follows:

(in millions)	**2007**	2006
Sales from Fortis Generation to Belize Electricity	**$ 15**	$ 17
Sales from Fortis Generation to FortisOntario	**1**	1
Sales from Newfoundland Power to Fortis Properties	**4**	3
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	**2**	2
Corporate to Fortis Properties	**8**	5
Fortis Generation to Belize Electricity	**–**	1

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2007**	2006
Interest paid	**$ 288**	$ 161
Income taxes paid	**$ 53**	$ 54

24. Financial Instruments

Fair Values

The Corporation has designated its financial instruments as follows:

	December 31, 2007		December 31, 2006	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents(1)	**$ 58**	**$ 58**	$ 41	$ 41
Loans and receivables				
Accounts receivable(1)(2)	**635**	**635**	286	286
Other receivables due from customers(1)(2)(3)	**7**	**7**	6	6
Other financial liabilities				
Short-term borrowings(1)(2)	**475**	**475**	98	98
Accounts payable and accrued charges(1)(2)	**793**	**793**	333	333
Dividends payable(1)(2)	**43**	**43**	22	22
Customer deposits(1)(2)(4)	**5**	**5**	5	5
Long-term debt, including current portion(5)(6)	**5,023**	**5,635**	2,614	2,940
Preference shares, classified as debt(5)(7)	**320**	**346**	320	355

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

(2) Carrying value approximates amortized cost

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

(4) Included in deferred credits on the balance sheet

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

(6) Carrying value at December 31, 2007 is net of unamortized deferred financing costs of $33 million. On January 1, 2007, deferred financing costs were reclassified from deferred charges and other assets in accordance with the transitional provisions of Section 3855.

(7) Preference shares classified as equity are excluded from the requirements of Section 3855; however, the estimated fair value of the Corporation's $122 million of preference shares classified as equity as at December 31, 2007 was $107 million (December 31, 2006 – $129 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by discounting the future cash flow of each debt instrument at the estimated yield to maturity for the same or similar issues at the balance sheet date, or by using available quoted market prices. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

Risk Management

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table indicates the valuation of derivative financial instruments as at December 31st.

	2007[(1)]				2006	
Liability	**Term to Maturity** *(years)*	**Number of Swaps**	**Carrying Value** *(in millions)*	**Estimated Fair Value** *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Interest Rate Swaps	**1 to 3**	**4**	**$ –**	**$ –**	$ –	$ (1)
Natural Gas Commodity Swaps and Options	**Up to 3**	**244**	**$ (79)**	**$ (79)**	$ –	$ –

[(1)] Includes derivative financial instruments of the Terasen Gas companies from May 17, 2007, the date of acquisition

Fortis Properties has designated its interest rate swap agreements as hedges of the cash flow risk related to floating-rate long-term debt. As at January 1, 2007, in accordance with the transitional provisions of Section 3865, the fair value of the interest rate swap agreements of $(1) million was recorded as a derivative financial instrument and grouped with deferred credits on the balance sheet with the offset reflected in accumulated other comprehensive loss (Note 16). The Terasen Gas companies have designated their interest rate swap agreements as hedges of cash flow risk related to floating-rate debt instruments. Any changes in the fair value of these interest rate swaps, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves.

The majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices and natural gas commodity swaps and options are used, therefore, to fix the effective purchase price of natural gas. As at December 31, 2007, none of the natural gas commodity swaps and options were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas commodity swaps and options, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. The fair values of the natural gas commodity swaps and options reflect the estimated amounts that the Terasen Gas companies would pay to terminate the contracts as at December 31, 2007, and were recorded in accounts payable as at December 31, 2007.

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

The Corporation has exposure to foreign currency exchange rate fluctuations associated with its US dollar-denominated operations. The Corporation may periodically enter into hedges of its foreign currency exposures on its foreign net investments by entering into offsetting forward exchange contracts and through the use of US dollar borrowings.

The Corporation's foreign net investments are exposed to changes in US dollar exchange rates. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with its foreign net investments through the use of US dollar borrowings. As at December 31, 2007, all of the Corporation's US$392 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's US dollar borrowings designated as hedges are recorded in the statement of comprehensive income (loss). As at December 31, 2007, the Corporation had approximately US$50 million in foreign net investments available to be hedged.

December 31, 2007 and 2006

24. Financial Instruments (cont'd)

Interest Rate Risk

Long-term debt is primarily issued at fixed interest rates, thereby minimizing cash flow and interest rate exposure. The Corporation is subject to risks associated with fluctuating interest rates primarily on its short-term and variable-rate credit-facility borrowings. The Corporation designates its interest rate swap contracts as hedges of the underlying debt. Interest expense on the debt is adjusted to include payments made or received under the interest rate swaps.

The Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Credit Risk

The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments and credit risk on physical off-system sales. Non-performance by the counterparties is not anticipated since these counterparties are high credit quality financial institutions. In addition, the Corporation is exposed to credit risk from customers. However, the Corporation generally has a large and diversified customer base, which minimizes the concentration of this risk. FortisAlberta, however, 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.

Rate Regulation

Certain of the Corporation's regulated utilities have rate stabilization accounts, which are approved by the regulators, to recover excess gas and energy costs over an established benchmark. These accounts minimize the impact of changing gas and energy costs on the financial results of the Corporation.

25. Commitments

(in millions)	**Total**	< 1 year	1–3 years	4–5 years	> 5 years
Gas purchase contract obligations (1)	**$ 537**	$ 515	$ 22	$ –	$ –
Power purchase obligations					
FortisBC (2)	**2,856**	40	74	76	2,666
FortisOntario (3)	**286**	21	43	45	177
Maritime Electric (4)	**7**	7	–	–	–
Belize Electricity (5)	**15**	2	2	2	9
Capital cost (6)	**402**	14	34	39	315
Joint-use asset and shared service agreements (7)	**66**	4	8	6	48
Office lease – FortisBC (8)	**20**	1	2	2	15
Operating lease obligations (9)	**176**	20	33	30	93
Other	**25**	6	10	9	–
Total	**$ 4,390**	$ 630	$ 228	$ 209	$ 3,323

(1) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2007.

(2) Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

(3) Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires on December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing, which expires on June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at $0.14 million per month.

(4) Maritime Electric has one take-or-pay contract with New Brunswick Power ("NB Power") for the purchase of either capacity or energy. This contract totals approximately $7 million through March 31, 2008.

(5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited, which commenced in February 2007, for the supply of 3 MW of capacity and a two-year power purchase agreement between Belize Electricity and Comisión Federal de Electricidad of Mexico, expiring in August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen"), which is scheduled to commence in mid-2009, that provides for the supply of approximately 14 MW of capacity. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(7) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2012 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

(8) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term (Note 4 *(xii)*).

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

The regulated subsidiaries of the Corporation are obligated to provide service to customers within their respective service territories. These regulated subsidiaries' capital expenditures are largely driven by customer requests or include large capital projects specifically approved by their respective regulators. The consolidated capital program of the Corporation, including non-regulated segments, is forecast to include approximately $901 million in capital expenditures for 2008. This commitment has not been included in the commitments table above.

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in 2007 and TGVI is expected to make an approximate $6 million repayment on the loans in 2008. As at December 31, 2007, the outstanding balance of the repayable government loans was $67 million with approximately $6 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the commitments table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVI's RDDA and the ability of TGVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

26. Contingent Liabilities

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

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

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister has 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. On June 22, 2007, TGI filed an appeal of the assessment with the B.C. Supreme Court (Note 4 *(x)*).

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

FortisAlberta

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately $3 million in firefighting and suppression costs and approximately $2 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date leads management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, FortisAlberta has not made any definitive assessment of potential liability, and the outcome with regard to the Company's liability for the claims made by the Crown is indeterminable. No amount, therefore, has been accrued in the Consolidated Financial Statements.

FortisBC

The B.C. 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 two filed writs and statements of claim by private landowners in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately $6 million on January 2, 2001 associated with a settlement with NB Power regarding its $450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and filed a Notice of Objection with the Chief of Appeals at CRA. 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, 2007, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the "Village"), New York. The Village 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 $7 million (US$7 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A Memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. An appeal of the summary judgment dismissal of the claim filed by the Village in January 2007 was heard by the Appellate Division, Fourth Judicial Department of the Supreme Court of the State of New York in December 2007. The Appellate Division delivered its Memorandum and Order on February 1, 2008 modifying the initial decision by dismissing the Village's appeal regarding its main claim, but reinstating a secondary cause of action dismissed by the summary judgment order. Further appeals to the New York State Court of Appeal may be forthcoming. Management believes that potential further legal actions by the Village will not be successful and, therefore, no provision has been made in the Consolidated Financial Statements.

27. Subsequent Event

On February 15, 2008, TGVI closed a $250 million 6.05% unsecured debenture offering, maturing on February 15, 2038. The net proceeds of the debenture offering were used to repay existing credit-facility borrowings.

28. Comparative Figures

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

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2007**	2006[1]	2005[1]	2004
Revenue, including equity income	**2,718**	1,472	1,441	1,146
Energy supply costs and operating expenses	**1,904**	939	926	766
Amortization	**273**	178	158	114
Finance charges	**299**	168	154	122
Corporate taxes	**36**	32	70	47
Results of discontinued operations, gains on sales and other unusual items	**8**	2	10	–
Non-controlling interest	**15**	8	6	6
Preference share dividends	**6**	2	–	–
Net earnings applicable to common shares	**193**	147	137	91
Balance Sheets *(in $ millions)*				
Current assets	**1,064**	405	299	293
Goodwill	**1,544**	661	512	514
Other long-term assets	**424**	331	471	418
Utility capital assets and income producing properties	**7,241**	4,044	3,315	2,713
Total assets	**10,273**	5,441	4,597	3,938
Current liabilities	**1,804**	558	412	538
Deposits due beyond one year	**–**	–	–	–
Deferred credits, regulatory liabilities and future income taxes	**688**	477	477	138
Long-term debt and capital lease obligations (excluding current portion)	**4,623**	2,558	2,136	1,905
Non-controlling interest	**115**	130	39	37
Preference shares (classified as debt)	**320**	320	320	320
Shareholders' equity	**2,723**	1,398	1,213	1,000
Cash Flows *(in $ millions)*				
Operating activities	**373**	263	304	272
Financing activities	**1,826**	456	224	777
Investing activities	**2,033**	634	467	1,026
Dividends, excluding dividends on preference shares classified as debt	**146**	77	64	51
Financial Statistics				
Return on average common shareholders' equity *(%)*	**9.99**	11.87	12.40	11.28
Capitalization Ratios *(%)* (year end)				
Total debt and capital lease obligations (net of cash)	**64.3**	61.1	58.7	61.4
Preference shares (classified as debt and equity)	**5.2**	10.0	8.6	9.4
Common shareholders' equity	**30.5**	28.9	32.7	29.2
Interest Coverage *(x)*				
Debt	**1.9**	2.2	2.5	2.3
All fixed charges	**1.7**	2.0	2.1	2.0
Total capital expenditures *(in $ millions)*	**803**	500	446	279
Common share data				
Book value per share (year end) *($)*	**16.69**	12.19	11.74	10.45
Average common shares outstanding *(in millions)*	**137.6**	103.6	101.8	84.7
Basic earnings per common share *($)*	**1.40**	1.42	1.35	1.07
Dividends declared per common share *($)*	**0.880**	0.700	0.605	0.548
Dividends paid per common share *($)*	**0.820**	0.670	0.588	0.540
Dividend payout ratio *(%)*	**58.6**	47.2	43.7	50.3
Price earnings ratio *(x)*	**20.7**	21.0	18.0	16.2
Share trading summary				
High price *($)* (TSX)	**30.00**	30.00	25.64	17.75
Low price *($)* (TSX)	**24.50**	20.36	17.00	14.23
Close price *($)* (TSX)	**28.99**	29.77	24.27	17.38
Volume *(in thousands)*	**100,920**	60,094	37,706	29,254

[1] As at December 31, 2006, the regulatory provision for future site removal and restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets.

	2003	2002	2001	2000	1999	1998	1997
	843	715	628	580	505	473	487
	579	477	418	418	356	340	341
	62	65	62	52	45	42	41
	86	74	65	56	46	44	45
	38	32	29	17	28	23	29
	–	–	4	3	–	4	–
	4	4	4	3	1	1	1
	–	–	–	–	–	–	–
	74	63	54	37	29	27	30
	191	180	135	166	93	94	79
	65	60	33	36	39	42	45
	345	241	172	163	122	121	115
	1,563	1,459	1,246	1,056	930	750	747
	2,164	1,940	1,586	1,421	1,184	1,007	986
	296	334	272	225	230	148	172
	–	–	–	–	16	16	20
	62	39	32	24	27	22	23
	1,031	941	746	678	488	424	386
	37	40	36	32	29	8	8
	123	–	50	50	50	50	50
	615	586	450	412	344	339	327
	157	134	94	97	85	69	63
	232	261	171	178	67	16	17
	308	349	240	241	122	66	54
	38	35	30	28	24	24	23
	12.30	12.23	12.44	9.73	8.55	8.24	9.43
	60.0	65.2	63.9	60.4	59.6	53.4	53.6
	6.7	–	3.6	4.3	5.1	6.0	6.2
	33.3	34.8	32.5	35.3	35.3	40.6	40.2
	2.2	2.3	2.3	2.1	2.3	2.2	2.6
	2.1	2.2	2.2	1.9	2.1	2.0	2.0
	208	229	149	158	86	65	50
	8.82	8.50	7.50	6.97	6.55	6.52	6.40
	69.3	65.1	59.5	54.1	52.2	51.5	50.4
	1.06	0.97	0.90	0.68	0.56	0.53	0.60
	0.525	0.498	0.470	0.460	0.455	0.450	0.443
	0.520	0.485	0.468	0.460	0.453	0.450	0.440
	48.9	49.9	51.9	67.6	80.8	84.9	73.9
	13.9	13.5	13.0	13.2	14.0	18.0	17.6
	15.24	13.28	11.89	9.19	9.93	12.03	10.63
	11.63	10.76	8.56	6.88	7.29	8.75	7.83
	14.73	13.13	11.74	9.00	7.85	9.56	10.50
	31,180	21,676	21,460	26,760	9,024	12,356	13,520

Board of Directors

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

Bruce Chafe ∗ ⋆ ✷ *Chair, Fortis Inc., St. John's, NL*
Mr. Chafe, 71, joined the Fortis Inc. Board in May 1997 and was appointed Chair of the Board in May 2006. He is past Chair of the Audit Committee of the Board. Mr. Chafe retired as a senior partner of Deloitte & Touche LLP after a 36-year career providing audit and corporate advisory services. He has been a Director of Fortis Properties Corporation since 1997. Mr. Chafe has served as Chair of Newfoundland Power Inc. and also as a Director of FortisBC Inc. He is a Director of several private investment firms. Mr. Chafe will be retiring from the Board at the Annual Meeting on May 6, 2008.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 53, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, BS*
Mr. Crothers, 63, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited. Mr. Crothers also serves as a Director of Abaco Markets, Templeton Investments, Nunisco Resources Limited, Talon Corporation, Fidelity Merchant Bank & Trust Limited, C.A. Bancorp Inc. and Victory Nickel Inc.

Geoffrey F. Hyland ✷ *Corporate Director, Caledon, ON*
Mr. Hyland, 63, joined the Fortis Inc. Board in May 2001. He retired as President and CEO of Shawcor Ltd. in June 2005. 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 ⋆ *Medical Practitioner, St. John's, NL*
Dr. Inkpen, 60, joined the Fortis Inc. Board in April 1994. She has been a medical practitioner since 1975 and is Chair of the Medical Advisory Committee for the St. John's Hospitals for Eastern Health. Dr. Inkpen is a past President of the College of the North Atlantic. She also served on the Royal Commission on Employment and Unemployment. Dr. Inkpen was appointed Chair of the Board of Fortis Properties Corporation in 2000 and is a past Chair of Newfoundland Power Inc.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 57, has served on the Fortis Inc. Board since October 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ∗ ⋆ *Professor of Finance, University of Manitoba, Winnipeg, MB*
Mr. McCallum, 64, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters ⋆ *President, Sumac Ridge Estate Wine Group, Summerland, BC*
Mr. McWatters, 62, joined the Fortis Inc. Board in May 2007. He is the founder of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Black Sage Vineyards Ltd., Hawthorne Mountain Vineyards Limited and Okanagan Estate Wine Cellars Ltd. and is responsible for government and industry relations in western Canada for Vincor Canada. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

David G. Norris ∗ ✷ *Corporate Director, St. John's, NL*
Mr. Norris, 60, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ✷ *Corporate Director, Moncton, NB*
Mr. Pavey, 60, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ⋆ ✷ *Corporate Director, Halifax, NS*
Mr. Rideout, 60, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of the Halifax International Airport Authority and NAV CANADA.

∗ Audit Committee
⋆ Governance and Nominating Committee
✷ Human Resources Committee

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

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F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan(1) and a Consumer Share Purchase Plan(2) to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional cash payments (minimum of $100, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares are sold quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent, Computershare Trust Company of Canada.

(1) All registered holders of Common Shares who are residents of Canada are eligible to participate in the Dividend Reinvestment Plan. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.

(2) The Consumer Share Purchase Plan is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; and First Preference Shares, Series F of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E and FTS.PR.F, respectively.

Valuation Day

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

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

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

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 9, 2008	August 8, 2008
November 7, 2008	February 6, 2009

Dividend Payment Dates

June 1, 2008	September 1, 2008
December 1, 2008	March 1, 2009

Earnings Release Dates

May 1, 2008	August 8, 2008
October 31, 2008	February 5, 2009

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

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 6, 2008
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Design and Production:
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www.colour-nl.ca

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The Lowe-Martin Group,
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For contact information on the Fortis Group of Companies, visit the "Contact Us" page of the Fortis Inc. website at www.fortisinc.com.

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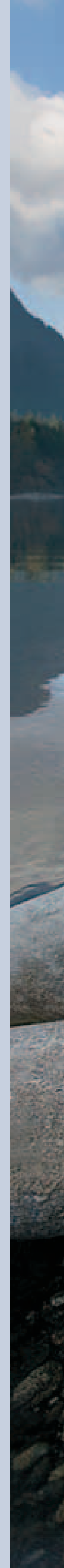
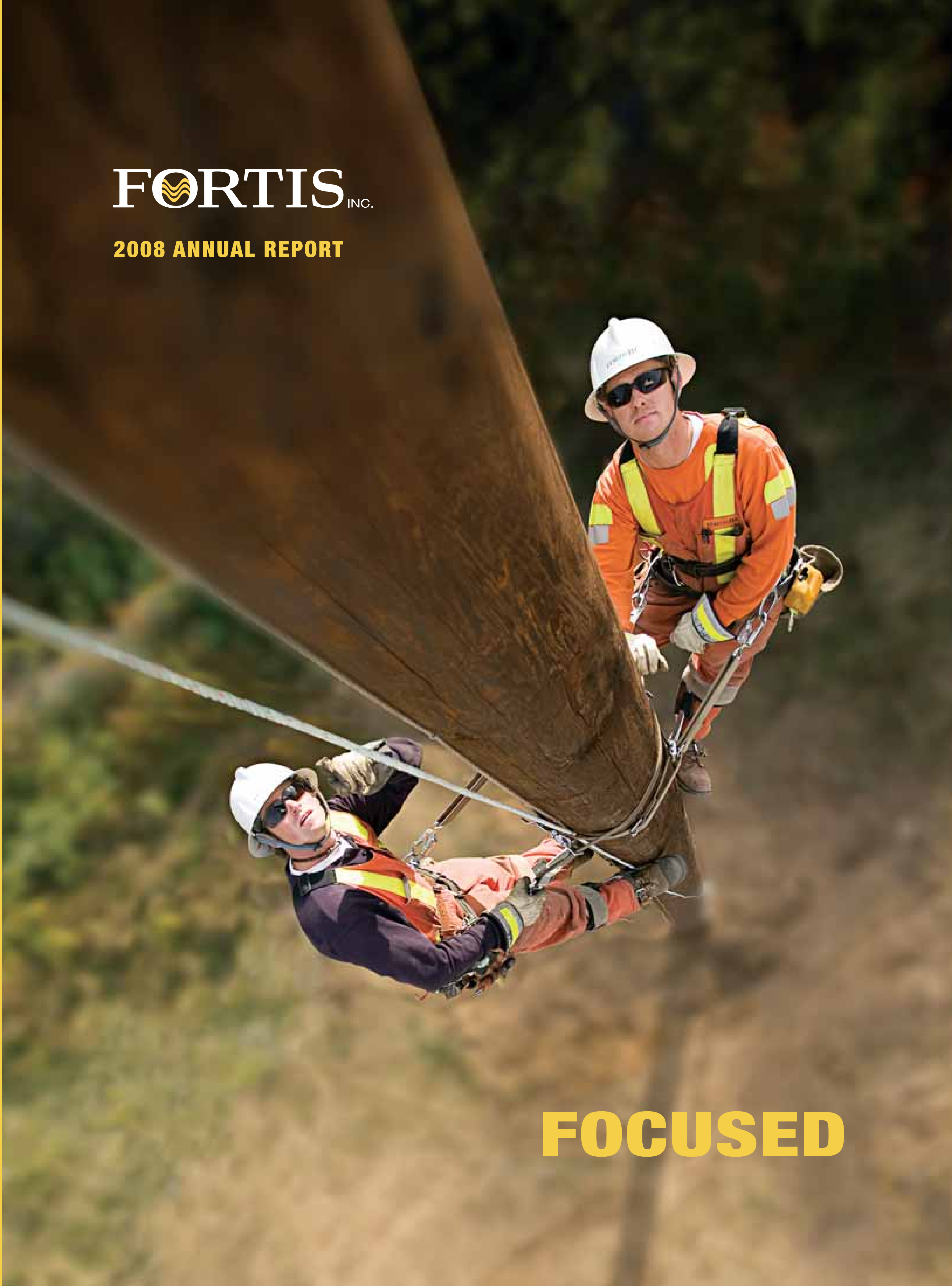


Fortis Inc.
2008 Annual Report



FORTIS INC.

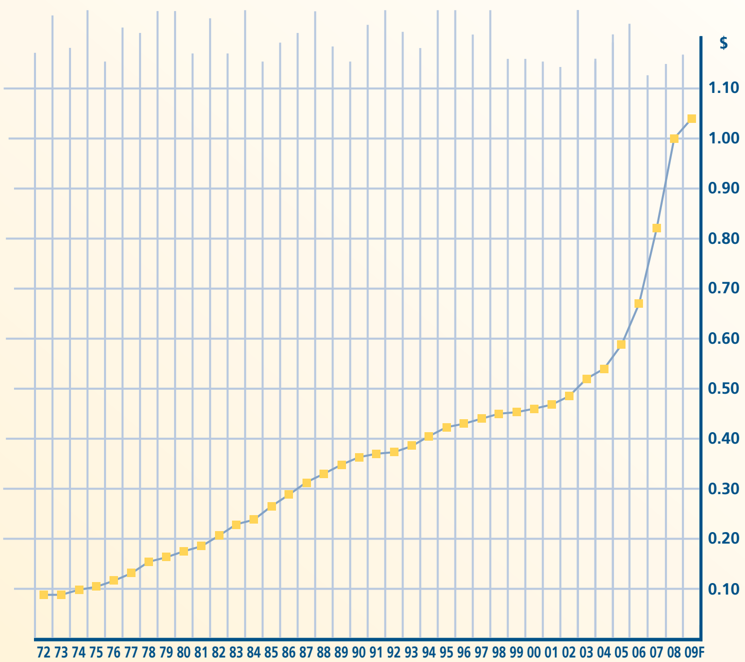
2008 ANNUAL REPORT

FOCUSED

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

Contents

Dividends paid per common share

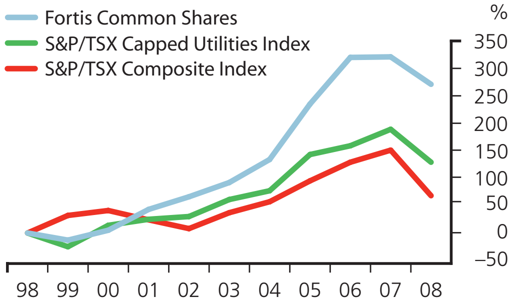


Fortis has increased its annual dividend to common shareholders for 36 consecutive years, the longest record of any public corporation in Canada.

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

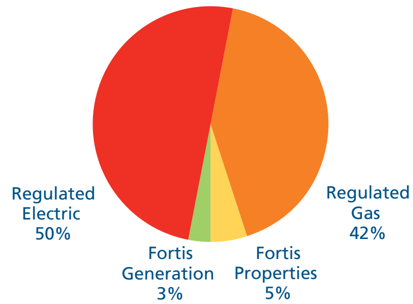
Back Cover Photo: Newfoundland Power Rattling Brook penstock
Photo taken by Gary Murray, Newfoundland Power employee

10-Year Cumulative Total Return



Total Assets Exceed $11 Billion

(as at December 31, 2008)



Regulated Utility Operations

Gas Operations

Terasen *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation

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

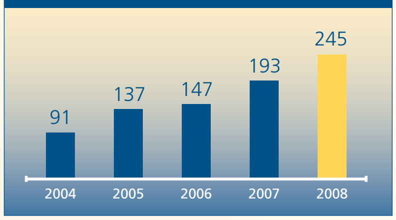
Fortis Properties

Real Estate
Atlantic Canada, Saskatchewan
Hotels
Eastern Canada, Manitoba, Saskatchewan, Alberta, British Columbia

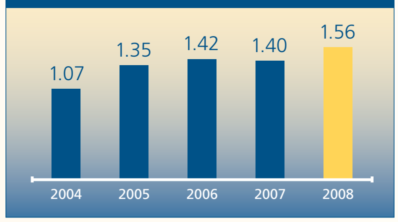
Investor Highlights

Five-Year Performance

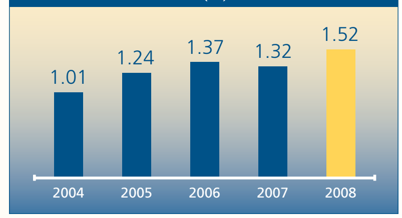
Earnings ($M)



Basic Earnings per Common Share ($)

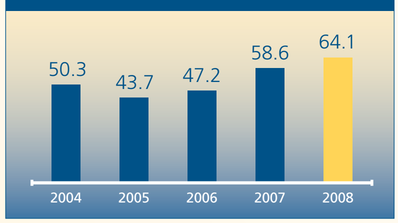


Diluted Earnings per Common Share ($)

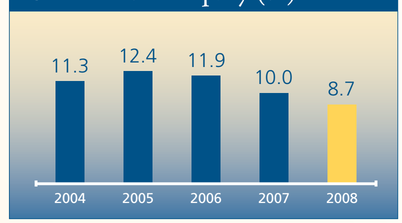


Dividends Paid per Common Share ($)

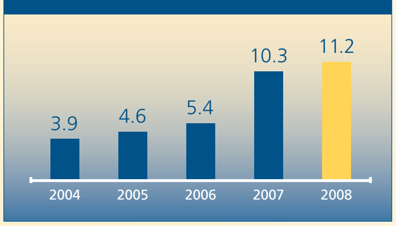
Dividend Payout Ratio (%)



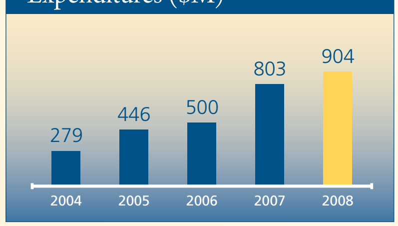
Return on Average Common Shareholders' Equity (%)



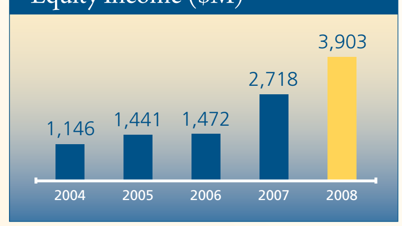
Assets ($B)



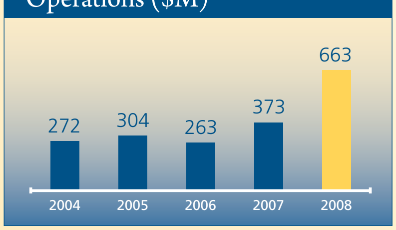
Capital Expenditures ($M)



Revenue and Equity Income ($M)

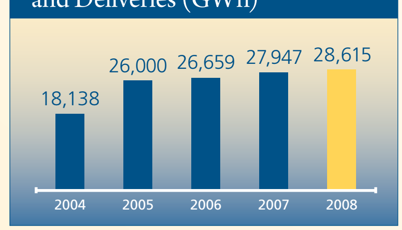


Cash Flow from Operations ($M)



Debt to Total Capitalization (%)

Electricity Sales and Deliveries (GWh)



All financial information is presented in Canadian dollars.

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

Regulated

Gas

Terasen(1)	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B)(2)	Earnings ($M)	Allowed ROE (%)(3) 2008	Allowed ROE (%)(3) 2009
Total	**931,000**	**1,260**	**1,402**	**221**	**220**	**4.6**	**3.1**	**118**	**8.62**	**8.47**

Electric

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

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

(2) Forecast mid-year 2009

(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.

(4) Interim ROE pending outcome of regulatory proceeding

(5) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to the consolidated earnings of Fortis, based on the Corporation's 70.1% ownership interest.

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

(7) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application

(8) Fortis holds a 57% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations as at and for the 14 months ended December 31, 2008 due to a change in the utility's fiscal year end. Earnings represent Caribbean Utilities' contribution to the Corporation's consolidated earnings for the 14 months ended December 31, 2008.

(9) Significant investment is currently occurring at the utility. 2008 achieved ROA was lower than the ROA allowed under the licence.

Non-Regulated

Fortis Generation(1)

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

Fortis Properties(2)

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

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

(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 20 hotels across Canada

(3) Includes $126 million in "Other" non-regulated assets

(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2008

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

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

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

Report to Shareholders

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

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

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

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

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

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

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

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

Left – Fortis, through its regulated and non-regulated businesses, owns and/or operates more than 1,800 MW of generation, mainly hydroelectric.

Right – The regulated utilities of Fortis serve more than 2,000,000 customers in five Canadian provinces and three Caribbean countries.

Report to Shareholders

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

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

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

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

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

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

Report to Shareholders

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

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

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

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

Fortis and its subsidiaries raised almost $1.2 billion in the capital markets in 2008. In December, the Corporation completed a $300 million common share issue, the net proceeds of which were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. In the second quarter of 2008, Fortis issued preference shares for gross proceeds of $230 million, the net proceeds of which were mainly used to repay $170 million borrowed under the Corporation's committed credit facility and to fund subsidiary equity requirements. Canadian Regulated Utilities issued $660 million of 30-year long-term debt at rates ranging from 5.80 per cent to 6.05 per cent. The proceeds provide long-term funding for capital programs to enhance reliability of gas and electricity service and meet customer growth.

At December 31, 2008, Fortis had consolidated credit facilities of $2.2 billion, of which $1.5 billion was unused. Approximately $2 billion of the total credit facilities are committed facilities, the majority of which have maturities ranging from 2011 to 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities. The Corporation's long-term debt maturities and repayments are expected to average approximately $180 million annually over the next five years. With its substantial credit facilities and conservative capital structure, we believe Fortis has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009.

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

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

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

Report to Shareholders

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

On behalf of the Board of Directors,

Geoffrey F. Hyland
Chair of the Board
Fortis Inc.

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

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

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

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

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

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

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

Terasen

Regulated Gas Operations

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving 931,400 customers in more than 125 communities or 96 per cent of gas users in the province. The Company delivers more than 20 per cent of the total energy consumed in British Columbia, comparable to the amount of electricity used in the province, making it a significant contributor to the province's energy mix.

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

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 834,000 customers. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. The Company serves approximately 95,000 customers. TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

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

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

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

Construction started on the approximate $200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008. The facility will allow for more efficient use of existing pipeline systems and improve reliability and security of supply during periods of system interruptions or increased energy demand. It is expected to come into service by late 2011.

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

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

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

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

FortisAlberta

Regulated Electric Operations

FortisAlberta is an electric utility that distributes electricity, generated by other market participants, to end-use customers in southern and central Alberta. Its electricity system includes approximately 108,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 461,000 customers in 175 communities and met a peak demand of 3,150 MW in 2008.

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

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

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

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

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

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

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

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

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

FortisBC

Regulated Electric Operations

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution lines and four regulated hydroelectric generating plants on the Kootenay River with a combined capacity of 223 MW. The annual gross energy entitlement from the plants is about 1,591 gigawatt hours ("GWh"). FortisBC also manages 904 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements, with the balance met through power purchase agreements. The Company met a record peak demand of 746 MW in 2008, exceeding the previous record of 718 MW reached in 2006.

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

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

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

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

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

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

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

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

Newfoundland Power

Regulated Electric Operations

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 236,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 30 small generating stations with an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,181 MW in 2008. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

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

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

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

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

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

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

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

Maritime Electric

Regulated Electric Operations

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI" or the "Island"), serves approximately 73,000 customers or 90 per cent of electricity consumers in the province. The Company owns and operates a fully integrated system comprised of approximately 5,300 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity throughout the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait. The utility met a peak demand of 223 MW in 2008.

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

In April 2008, a refurbishment began on the Point Lepreau Generating Station that will extend its life by 25 years and provide additional stability with respect to long-term energy supply. The balance of the Company's energy requirements is obtained from on-Island wind-powered generation facilities and from the utility's own generating plants. Approximately 13 per cent of total energy supply was derived from wind-powered generation in 2008.

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

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

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


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

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

FortisOntario

Regulated Electric Operations

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

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

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

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

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

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

The Government of Ontario has mandated all regulated electric utilities in the province to install smart meters, which track time-of-use consumption data, at customer sites by the end of 2010. During 2008, FortisOntario selected a supplier of smart meters and installation of this new technology is scheduled to begin by mid-2009. Approximately 27,000 of the utility's metered customers will move to time-of-use rates by the end of 2010.

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

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

Belize Electricity

Regulated Electric Operations

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 74,000 customers, the utility met a peak demand of 74 MW in 2008 from multiple sources of energy, including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE") (the Mexican state-owned power company), Hydro Maya Limited and its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 34 MW and owns approximately 2,840 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

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

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

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

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

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

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

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

Caribbean Utilities

Regulated Electric Operations

Caribbean Utilities generates, transmits and distributes electricity to more than 24,000 customers on Grand Cayman, Cayman Islands. The utility owns and operates approximately 555 kilometres of transmission and distribution lines and 24 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis has an approximate 57 per cent controlling ownership interest in the utility.

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

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

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

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

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

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

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

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

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

Fortis Turks and Caicos

Regulated Electric Operations

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

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

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

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

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

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

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

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

Fortis Generation

Non-Regulated Operations

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State with a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

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

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

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

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

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

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

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

Fortis Properties

Non-Regulated Operations

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

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

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

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

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

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

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

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

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

Our Community

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

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

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

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

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

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

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

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

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

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

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

Management Discussion and Analysis

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

Dated March 11, 2009

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2008 Consolidated Financial Statements and Notes to the 2008 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2008 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of regulatory decisions; the electricity sales growth rate expected at the Corporation's regulated utilities in the Caribbean in 2009; consolidated forecasted gross capital expenditures for 2009 and in total over the next five years, as well as the expected significant capital projects in 2009 and their expected costs and time to complete; the expected impacts on Fortis of the downturn in the global economy; the expected increase in activities at Terasen Energy Services; no significant decrease in subsidiary operating cash flows is expected in 2009; the subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs; the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009; expected long-term debt maturities and repayments in 2009 and on average annually over the next five years; no material increase in interest expense and/or fees associated with renewed and extended credit facilities is expected in 2009; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2009; the estimated impact a decease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of no material increase in defined benefit pension expense in 2009. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2009; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; an ultimate resolution of the Exploits River Hydro Partnership that differs from what is currently expected by management; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk;

competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; an unexpected outcome of legal proceedings currently against the Corporation; licences and permits; loss of service area; market energy sales prices; transition to International Financial Reporting Standards; changes in tax legislation; First Nations' lands; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2008.

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

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility in Canada serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State and hotels and commercial real estate in Canada. In 2008, the Corporation's electricity distribution systems met a combined peak electricity demand of more than 5,700 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,402 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, Fortis pursues profitable growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably to customers at reasonable rates, and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The operating segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates which factor into customer rate-setting mechanisms.

Fortis holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 195 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility and enhance shareholder return.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 834,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 95,000 residential, commercial and industrial customers.

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

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 461,000 customers.

b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 236,000 customers. Newfoundland Power has an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 73,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

a. *Belize Electricity:* Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 74,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

b. *Caribbean Utilities:* Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 24,000 customers. The Company has an installed generating capacity of approximately 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

c. *Fortis Turks and Caicos:* Includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

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

a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

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

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

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

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

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

Financial Highlights

For the Years Ended December 31	2008	2007	Variance *(%)*
Net Earnings Applicable to Common Shares *($ millions)*	**245**	193	26.9
Basic Earnings per Common Share *($)*	**1.56**	1.40	11.4
Diluted Earnings per Common Share *($)*	**1.52**	1.32	15.2
Weighted Average Number of Common Shares Outstanding *(millions)*	**157.4**	137.6	14.4
Revenue *($ millions)*	**3,903**	2,718	43.6
Dividends Paid per Common Share *($)*	**1.00**	0.82	22.0
Return on Average Common Shareholders' Equity *(%)*	**8.7**	10.0	(13.0)
Total Assets *($ millions)*	**11,178**	10,273	8.8
Cash Flow From Operating Activities *($ millions)*	**663**	373	77.7

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

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

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

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

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

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

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

Regulator-Allowed ROE

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

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

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

Economic growth in the province of Alberta has been robust in the past few years translating into strong customer, energy sales and rate base growth at FortisAlberta. The rate of growth may decrease in 2009 due to the current global economic environment and depressed world oil prices. FortisAlberta's service territory includes the environs of Calgary and Edmonton as well as the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC and the Terasen Gas companies over the past few years. Sales growth in 2008 at FortisBC was tempered due to decreased activity in the forestry sector. Organic earnings growth from the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta, FortisBC and the Terasen Gas companies. The Corporation's other Canadian regulated electric utilities, Newfoundland Power, Maritime Electric and FortisOntario, are expected to generate slower earnings' growth.

Regulated assets in the Caribbean region, as a percentage of the Corporation's total regulated assets, were 10 per cent at December 31, 2008 (December 31, 2007 – 8 per cent). The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher than that achieved in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. However, the allowed ROAs at Caribbean Utilities and Belize Electricity were lowered in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Economic growth has been strong in the Corporation's service territories in the Caribbean, positively impacting customer and sales growth. The rate of growth is expected to be lower in 2009 due to the impact of the global economic downturn. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

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

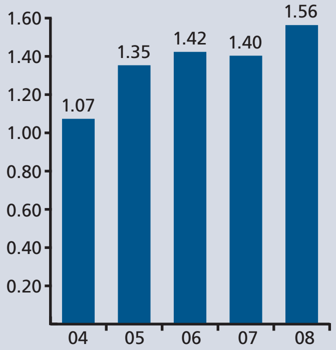
In Canada, regulator-approved negotiated settlement agreements were reached at FortisAlberta and FortisBC for 2008 and 2009 electricity rates and at Newfoundland Power for 2008 electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of full-scale public hearing processes. Customer rates at Newfoundland Power and the Terasen Gas companies have also been set for 2009.

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

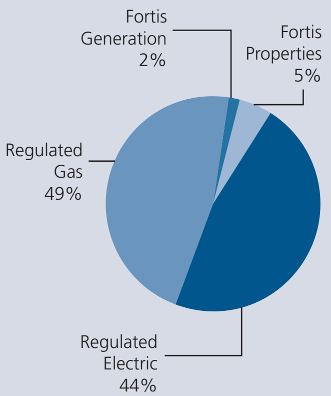
Common share dividend payments increased to $1.00 per common share in 2008. Effective for the first quarter of 2009, a 4 per cent increase in the quarterly common share dividend to 26 cents from 25 cents extends the Corporation's record of annual common share dividend increases to 36 consecutive years,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

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

Basic Earnings per Common Share *($)*

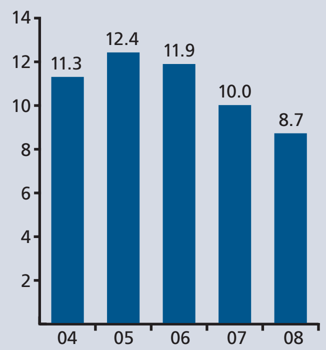


Revenue[1]
(year ended December 31, 2008)



[1] Excludes Corporate and Other

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



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of $245 million in 2008, a 26.9 per cent increase over earnings of $193 million in the previous year. The increase in earnings was primarily due to earnings' contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian regulated utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time $13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate tax recoveries at FortisAlberta. Results for 2008 also reflected a $7.5 million tax reduction ($5.5 million at the Terasen Gas companies and $2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen. Results for 2007 reflected a $7 million after-tax gain on the sale of surplus land at TGI.

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

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

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

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

2008 Capital Expenditures: During 2008, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $904 million, including capital expenditures of approximately $220 million at the Terasen Gas companies. Total capital investment at FortisAlberta and FortisBC during 2008 was approximately $419 million, representing approximately 46 per cent of total gross capital expenditures. Much of the capital investment was driven by customer growth and the need to enhance the reliability of electricity systems.

Management Discussion and Analysis

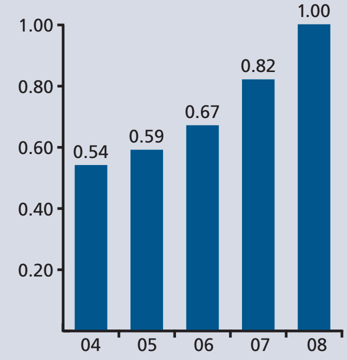
Dividends: Dividends paid per common share increased to $1.00 in 2008, up 22.0 per cent from 82 cents in 2007. Commencing with the first quarter dividend paid on March 1, 2009, Fortis increased its quarterly common share dividend 4 per cent to 26 cents from 25 cents. The Corporation's dividend payout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

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

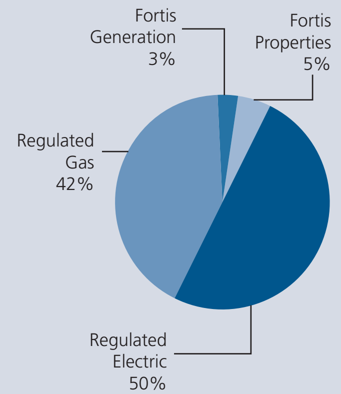
Asset Growth: Total assets increased 8.8 per cent to approximately $11.2 billion at the end of 2008 compared to approximately $10.3 billion at the end of 2007. The increase was primarily due to the Corporation's continued investment in energy systems at FortisAlberta, FortisBC and the Terasen Gas companies,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

Financings: During 2008, Fortis and its utilities raised almost $1.2 billion of capital from a combination of preference share, common share and long-term debt issues. In the second quarter of 2008, the Corporation publicly issued 9.2 million 5.25% Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million under the Corporation's committed credit facility, fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. At the subsidiary level, TGVI issued $250 million of 30-year 6.05% unsecured debentures in February; FortisAlberta issued $100 million of 30-year 5.85% unsecured debentures in April; Maritime Electric issued $60 million of 30-year 6.05% secured first mortgage bonds in April; and TGI issued $250 million of 30-year 5.80% unsecured debentures in May. Proceeds from the long-term debt issues at the utilities were primarily used to repay indebtedness under credit facilities incurred in support of capital spending. Additionally, partial proceeds from the issuance of the $250 million unsecured debentures by TGI were used to refinance $188 million of debt that matured in May 2008.

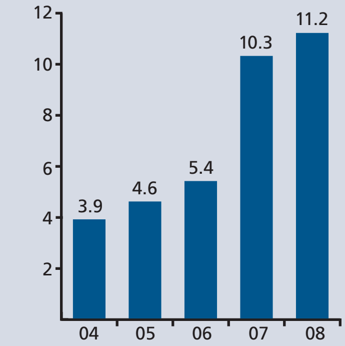
Dividends Paid per Common Share *($)*



Total Assets
(as at December 31, 2008)



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



Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

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

(1) Financial results are reported from May 17, 2007, the date of acquisition.

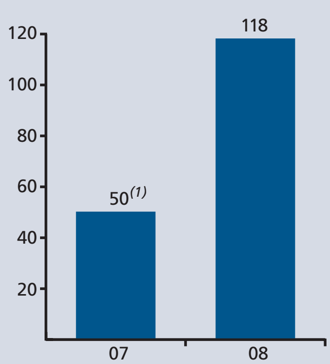
(2) Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which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

(3) Includes the results of the Fairmont Newfoundland hotel from November 2008, the date of acquisition

REGULATED UTILITIES

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

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



(1) Earnings are from May 17, 2007

Regulated Gas Utilities – Canadian

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

Terasen Gas Companies

Financial Highlights

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

(1) Results are reported from May 17, 2007, the date of acquisition.

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

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

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

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

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

Earnings: Earnings were $118 million for 2008 compared to $50 million for the partial year in 2007. Earnings for 2007 were favourably impacted by a $7 million after-tax gain on the sale of surplus land. Earnings for 2008 included an approximate $5.5 million tax reduction associated with the settlement of historical corporate tax matters. During the third quarter of 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency ("CRA") related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures.

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

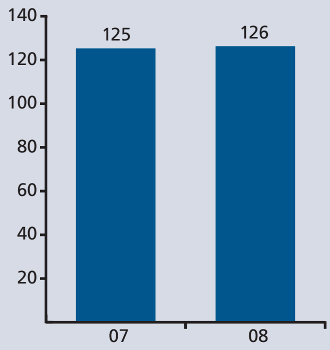
Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is used for space heating. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

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

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

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

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



Regulated Electric Utilities – Canadian

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

FortisAlberta

Financial Highlights

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

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

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

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

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

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

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

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

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

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

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

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

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

FortisBC

Financial Highlights

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

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

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

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

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

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

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

Newfoundland Power

Financial Highlights

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

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

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

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

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

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

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

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

Other Canadian Electric Utilities[1]

Financial Highlights

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

(1) Includes Maritime Electric and FortisOntario

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

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

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

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

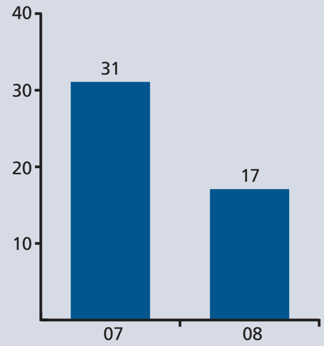
In October 2008, FortisOntario entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc. for a cash payment of approximately $1 million plus the provision of services to integrate Grimsby Power Inc.’s customer information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

Outlook: In March 2009, Maritime Electric received regulatory approval of its 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The regulator also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.

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

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

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



Regulated Electric Utilities – Caribbean

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

Regulated Electric Utilities – Caribbean(1)

Financial Highlights

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NON-REGULATED

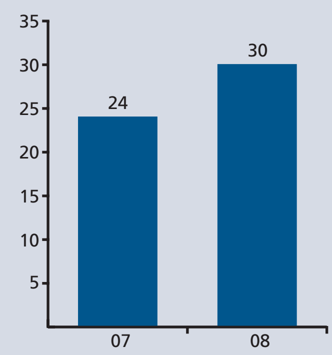
Non-Regulated – Fortis Generation[(1)]

Financial Highlights

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

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

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



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

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

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

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

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

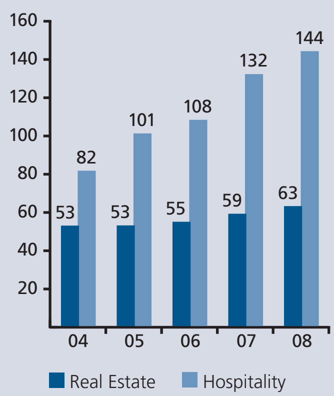
Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31

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

Fortis Properties Revenue *($ millions)*



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

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

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

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

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

The Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure.

Corporate and Other(1)

Financial Highlights

Years Ended December 31

($ millions)	**2008**	2007(1)	Variance
Revenue	**26**	22	4
Operating Expenses	**16**	13	3
Amortization	**8**	6	2
Finance Charges(2)	**80**	70	10
Corporate Tax Recovery	**(23)**	(12)	(11)
Preference Share Dividends	**14**	6	8
Net Corporate and Other Expenses	**(69)**	(61)	(8)

(1) Includes Fortis net corporate expenses and, from May 17, 2007, the net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

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

Revenue: Revenue was $4 million higher than the previous year. Higher interest revenue from increased inter-company lending was combined with increased revenue contributions from CWLP. CWLP contributed revenue for a full year in 2008 compared to a partial year in 2007; however, this increase was partially offset by the impact of a decrease in the number of customer contracts at CWLP.

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

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

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

Regulatory Highlights

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity *(%)*	Allowed Returns *(%)* 2007	2008	2009	Supportive Features Future or Historical Test Year Used to Set Rates
				ROE		Cost of Service ("COS")/ROE PBR mechanism through 2009:
TGI	BCUC	35	8.37	8.62	8.47	TGI: 50/50 sharing of earnings above or below the allowed ROE
TGVI	BCUC	40	9.07	9.32	9.17	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
FortisBC	BCUC	40	8.77	9.02	8.87	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
FortisAlberta	AUC	37	8.51	8.75	8.51[(1)]	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.60 +/– 50 bps	8.95 +/– 50 bps	8.95 +/– 50 bps	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	10.25	10.00	9.75	COS/ROE Future Test Year
FortisOntario	OEB (Canadian Niagara Power) 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		Four-year COS/ROA agreements
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00	10.00[(3)]	Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	15.00	9.00 – 11.00	9.00 – 11.00	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new licences, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50[(4)]	17.50[(4)]	17.50[(4)]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

(1) Interim ROE pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding

(2) Allowed deemed equity component of the capital structure for 2009. For 2008, the allowed deemed equity component of the capital structure was 46.7 per cent.

(3) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application

(4) Amount provided under licence. Actual ROAs achieved in 2007 and 2008 were lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI/TGVI	• In December 2007, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflected the impact of an increase in the allowed ROE for 2008 to 8.62 per cent and 9.32 per cent for TGI and TGVI, respectively. • On April 1, 2008, final regulatory approval for the construction of the 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was received for a total estimated cost of approximately $200 million. • Every three months, TGI and TGVI review natural gas and propane commodity prices with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane. Effective April 1, 2008 and July 1, 2008, the BCUC approved increases in the commodity rates charged to TGI customers for natural gas and propane. Effective October 1, 2008, the BCUC approved decreases in the commodity rates charged to TGI customers for natural gas. The commodity cost of natural gas and propane are flowed through to customers without markup. During 2008, no commodity rate changes were made at TGVI. • In December 2008, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2009. The approved rates also reflected the impact of a decrease in the allowed ROE for 2009 to 8.47 per cent and 9.17 per cent for TGI and TGVI, respectively, resulting from the application of automatic ROE adjustment mechanisms. The commodity rate for natural gas will remain unchanged and the commodity rate for propane will decrease effective January 1, 2009. • TGI filed an application with the BCUC in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive regulatory approval for this $27 million project in early 2009 with completion of the project anticipated in 2010. • TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC in the second quarter of 2009. The BCUC approval of rates for 2010 and future years will be required as the current PBR agreements expire at the end of 2009. As part of the rate filings, TGI and TGVI plan to seek a review of the current generic ROE adjustment mechanisms and the deemed equity component of the utilities' capital structures.
FortisBC	• In December 2007, regulatory approval was received for the NSA associated with 2008 revenue requirements resulting in a customer rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's capital expenditure program. Rates for 2008 reflected an allowed ROE of 9.02 per cent. • In April 2008, the BCUC approved an interim increase of 0.8 per cent to FortisBC's customer rates, effective May 1, 2008, as a result of BC Hydro's interim rate increase, which increased FortisBC's cost to purchase power from BC Hydro by 5.06 per cent. • In June 2008, FortisBC filed its 2009 and 2010 Capital Expenditure Plan for gross capital expenditures of approximately $193 million for 2009 and $196 million for 2010. In November 2008, the BCUC denied the costs relating to the Copper Conductor Replacement Project and Advanced Metering Infrastructure Project included in the 2009 and 2010 Capital Expenditure Plan. These projects would have totalled approximately $21 million in 2009 and $27 million in 2010. In February 2009, the BCUC issued its decision on the Company's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of $165 million were approved for 2009 and $156 million were approved for 2010. An additional $16 million of capital expenditures is subject to further regulatory processes. • In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The rate increase is primarily the result of the Company's capital expenditure program and higher power purchases driven by customer growth and increased electricity demand. Rates for 2009 reflect an allowed ROE of 8.87 per cent as a result of the application of the automatic ROE adjustment mechanism. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the consumer price index ("CPI") for British Columbia minus a productivity improvement factor ("PIF") of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess is to be added to the PIF, which effectively caps the CPI at 3 per cent.
FortisAlberta	• Effective January 1, 2008, FortisAlberta became regulated by the AUC due to the separation of the Alberta Energy and Utilities Board into two separate regulatory bodies. • In February 2008, regulatory approval was received of the NSA associated with 2008/2009 revenue requirements, resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately $264 million for 2008 and $296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 allowed ROE of 8.51 per cent. The impact of the increase in the allowed ROE to 8.75 per cent for 2008 was subject to deferral-account treatment and, as such, was recognized as earned in 2008 and will be collected in customer rates in 2009.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2008, the AUC ruled that a review of ROE levels, adjustment mechanisms and utility capital structures in a generic proceeding would be appropriate. In July 2008, the AUC issued its notice of application, preliminary scoping document and minimum filing requirements for the 2009 Generic Cost of Capital Proceeding. The proceeding applies to all gas, electric and pipeline utilities in Alberta that are regulated by the AUC. • In November 2008, FortisAlberta submitted its evidence with respect to the 2009 Generic Cost of Capital Proceeding as requested by the AUC. A hearing is scheduled for the second quarter of 2009. • In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result is a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase is slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflect the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. As directed by the AUC, the Company is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, pending the outcome of the 2009 Generic Cost of Capital Proceeding. • FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.
Newfoundland Power	• In December 2007, the PUB approved the Company's NSA associated with the 2008 general rate application, resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase was largely driven by higher amortization costs. The rate increase also reflected the impact of an increase in the allowed ROE to 8.95 per cent for 2008. • The PUB-approved NSA also results in, among other things: (i) the amortization of $7.2 million in 2008 and $4.6 million in each of 2009 and 2010 of the remaining $16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately $3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three years to five years of certain deferred regulatory balances; and (iv) for 2008 through 2010, the deferral of variations in purchase power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account. • Effective July 1, 2008, the PUB approved an average 5.9 per cent increase in customer electricity rates, reflecting the flow through to customers, by operation of the rate stabilization account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The increase in customer rates had no impact on Newfoundland Power's earnings in 2008. • In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately $62 million, with approximately half of the proposed capital expenditures relating to replacing aged and deteriorated components of the electricity system. • The Company's allowed ROE of 8.95 per cent remains unchanged for 2009 and, consequently, there has been no change in basic customer rates for 2009.
Maritime Electric	• In January 2008, IRAC approved, as filed, an increase in basic electricity rates of 1.8 per cent, effective April 1, 2008, and approved a maximum allowed ROE of 10.0 per cent for 2008. • In April 2008, IRAC ordered the energy cost adjustment mechanism ("ECAM") amortization period of 12 months to be set at 8 months, effective May 1, 2008. The result is an increase in the flow through in customer rates of the recovery of ECAM over the shorter amortization period. • In September 2008, IRAC approved, as filed, the Company's amendment of approximately $14 million to its 2008 Capital Budget to reflect the construction of a new transmission line to facilitate the expansion of merchant wind development. The project is being financed entirely by customer contributions. • In November 2008, IRAC approved, as filed, the Company's 2009 Capital Budget Application for approximately $20 million, before customer contributions. • In March 2009, IRAC approved Maritime Electric's 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kWh to 7.7 cents per kWh will result in a decrease in the amount of energy costs to be collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau Nuclear Generating Station replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.
FortisOntario	• In March 2008, the OEB issued its decision relating to the 2008 Incentive Regulation Mechanism ("IRM") application filed by Canadian Niagara Power. The result was an average 1.1 per cent increase in electricity distribution rates for operations in Fort Erie, Port Colborne and Gananoque, effective May 1, 2008. The increase was comprised of a 2.1 per cent increase for inflation, partially offset by a 1.0 per cent decrease for a productivity adjustment. Under the 2008 IRM, Canadian Niagara Power's capital structure for 2008 was deemed at 53.3 per cent debt and 46.7 per cent equity, as part of the OEB's plan to move to a 60 per cent debt and 40 per cent equity capital structure over a three-year period.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• Effective July 1, 2008, retail rates at Cornwall Electric decreased by approximately 6.2 per cent, attributable to a new 11.5-year wholesale electricity supply contract negotiated with Hydro-Québec Energy Marketing by Cornwall Electric on behalf of its customers. The new long-term agreement replaces an existing short-term contract and ensures reliability of supply and rate stability. • In August 2008, Canadian Niagara Power filed a 2009 Cost of Service Application requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The application proposes distribution rate increases of 4.9 per cent, 9.4 per cent and 7.1 per cent for Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009. The proposed increases are primarily driven by the impact of distribution system upgrades. The hearing process associated with the application commenced during the fourth quarter of 2008 and the Company expects a decision on the application to be received in April 2009.
Belize Electricity	• In March 2008, the newly elected Government of Belize repealed December 2007 amendments to the *Electricity (Tariffs, Charges and Quality of Services Standards) Bylaws*. The amendments had simplified Belize Electricity's rate-setting methodology, allowed for improved rate stabilization and settled outstanding matters related to the PUC's Final Decision on electricity rates for the period July 1, 2007 through June 30, 2008. • In March 2008, Belize Electricity filed an application requesting an increase in the cost of power component of the average electricity rate by 15 per cent, or BZ6.5 cents per kilowatt hour ("kWh"), as a result of the rapid increase in the cost of power due to increasing world oil prices. The application was disallowed by the PUC which cited that, in the interim, a decrease in the Company's operating expenses and capital expenditure levels would help offset the impact on cash flow of the increasing cost of power. Additionally, the PUC indicated it would defer its detailed analysis of the high deferrals of cost of power into Belize Electricity's cost of power rate stabilization account ("CPRSA") until the Annual Tariff Review Proceeding for the annual tariff period for July 1, 2008 to June 30, 2009. • In April 2008, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2008 to June 30, 2009 ("2008/2009 Rate Application") requesting a 13.4 per cent increase in the average electricity rate, as a result of an increase in the cost of power component of the rate and an increase in the recovery of the CPRSA. • In May 2008, the PUC issued its Initial Decision on Belize Electricity's 2008/2009 Rate Application. The Initial Decision denied any average rate increase and approved, among other things, a retroactive adjustment to Belize Electricity's CPRSA. Belize Electricity objected to the Initial Decision, which resulted in a review of the Initial Decision by a PUC-appointed Independent Expert. The report of the Independent Expert reiterated many of Belize Electricity's concerns pertaining to the Initial Decision. • In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application which rejected most of the recommendations of the Independent Expert and failed to increase the overall average electricity rate. The PUC also ordered a BZ$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. The Final Decision would have the impact of reducing the Corporation's share of Belize Electricity's earnings by approximately $5 million over a 12-month period. The Final Decision does not impact the Corporation's non-regulated generation operations in Belize. • As a direct result of the Final Decision, Belize Electricity recorded an $18 million (BZ$36 million) charge ($13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. • The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactive effective September 1, 2008, allows for the collection from, or rebate to, customers of actual costs of power which vary from a reference cost of power by more than a threshold of 10 per cent. • In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. • Changes made in electricity legislation by the Government of Belize and the PUC and the June 2008 Final Decision and Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely outcome of the proceedings is indeterminable at this time.

Material Regulatory Decisions and Applications (cont'd)

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

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2008 and December 31, 2007.

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

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

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

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

Liquidity and Capital Resources

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

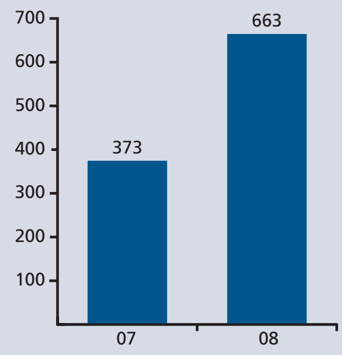
Summary of Cash Flows

Years Ended December 31

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

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

Cash Flow from Operating Activities
($ millions)



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

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

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

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

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations, and net borrowings (repayments) under committed credit facilities for 2008 compared to 2007 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

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

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

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

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

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

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

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

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

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

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

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

Repayment of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

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

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

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

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

Borrowings by the utilities under credit facilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt and/or cash from operations. From time to time, proceeds from preference share, common share and long-term debt issues are used to repay borrowings under the Corporation's committed credit facility.

Net proceeds associated with the issuance of common shares under the Corporation's share purchase and stock option plans in 2008 were $21 million compared to $23 million in 2007. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately $300 million ($287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire $200 million of debt at Terasen that matured on December 1, 2008, and for general corporate purposes. In May 2007, the Corporation publicly issued 44.3 million common shares for gross proceeds of approximately $1.15 billion ($1.1 billion net of costs) to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million common shares were publicly issued for gross proceeds of approximately $150 million ($143 million net of costs). Partial net proceeds from the common share issue in January 2007 were used to repay indebtedness incurred under the Corporation's committed credit facility. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

During the second quarter of 2008, the Corporation issued 9.2 million First Preference Shares, Series G for gross proceeds of approximately $230 million ($223 million net of costs). The net proceeds were used to repay $170 million under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes.

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

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

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

Contractual Obligations

As at December 31

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

(1) In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in

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

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

(3) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.

(4) Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

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

(6) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. These contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.

(7) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's contractual obligations.

(8) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(9) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also

entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

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

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

Other Contractual Obligations: Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

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

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

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

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

Capital Structure: The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

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

Capital Structure

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

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

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

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

The Corporation's credit ratings are as follows:

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

During the fourth quarter of 2008, S&P and DBRS confirmed the Corporation's unsecured corporate debt credit ratings. The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2008, approximately $94 million in maintenance and repairs was expensed compared to approximately $87 million during 2007. The increase year over year largely reflected inclusion of the financial results of the Terasen Gas companies for a full year in 2008.

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

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

Gross Capital Expenditures

Year Ended December 31, 2008

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

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

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

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

(4) Includes expenditures associated with assets under construction

Gross consolidated capital expenditures for 2009 are expected to be approximately $1 billion. Planned capital expenditures are based on detailed forecasts of customer demand, weather, and cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

A summary of forecast gross capital expenditures for 2009 by segment and by asset category is provided in the following table.

Forecast Gross Capital Expenditures

Year Ending December 31, 2009

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

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

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

Gross Capital Expenditures

Year Ended December 31

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

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

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

Significant Capital Projects

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cash Flow Requirements: At the operating subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt issues.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under its committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The Corporation does not expect any significant decrease in subsidiary operating cash flows in 2009 as a result of the anticipated continued downturn in the global economy. The subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately $240 million in 2009 and to average approximately $180 million annually over the next five years. The combination of available credit facilities, as discussed in more detail below, and low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to the capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

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

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

Credit Facilities: As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which approximately $1.5 billion was unused, including $568 million unused under the Corporation's $600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

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

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

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

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

Credit Facilities

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

At December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

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

Corporate and Other

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

Regulated Utilities

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

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

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

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

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

Off-Balance Sheet Arrangements

As at December 31, 2008, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

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

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with regulators and local governments to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2008 (2007 – 90 per cent), while approximately 83 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2008 (2007 – 81 per cent). The regulated utilities, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. The uncertainties include approvals by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. Generally, the ability of the utilities to recover the actual costs of providing services and earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

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

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

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

TGI, TGVI and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGVI expire in 2009. In December 2008, the PBR mechanism at FortisBC was extended for the periods from 2009 to 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a different formula. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be.

Further information on the new PBR mechanism at FortisBC and the nature of regulation and various regulatory matters pertaining to the Corporation's utilities is provided in the "Regulatory Highlights" section of this MD&A.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas which could result in significant operational and/or environmental liability. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace their assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain as to whether any additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the growth of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, gas distribution volumes may not grow as quickly as in the past. In the Caribbean, the level of and fluctuations in tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activity in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available for compensating for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending which would, in turn, impact rate base and earnings' growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial real estate and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 11 per cent per annum over the next five years. Approximately 57 per cent of Fortis Properties' operating income was derived from hotel investments in 2008 (2007 – 58 per cent). Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the finance charges of the Corporation and its utilities. Also, a significant downgrade in TGI or Terasen Inc.'s credit ratings could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. As discussed in the "Liquidity and Capital Resources – Capital Structure" section of this MD&A, the Corporation's corporate investment-grade credit ratings were confirmed and maintained during the fourth quarter of 2008. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The volatility in the global financial and capital markets may increase the cost of, and affect the timing of, issuance of long-term capital by the Corporation and its utilities in 2009. While the cost of borrowing is expected to increase, as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. Due to the regulated nature of the Corporation's utilities, increased borrowing costs are eligible to be recovered in future customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes. The cost of renewed and extended credit facilities may also increase going forward; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its utilities in 2009 as the majority of the total committed credit facilities have maturities beyond 2009.

Further information about the Corporation's credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 26 to the 2008 Consolidated Financial Statements.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air-conditioning demand while warm winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air-conditioning demand is less pronounced due to less variable climatic conditions that exist in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

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

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Under its new T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, including a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

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

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated through the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or through the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

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

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00. The Corporation has also designated all of its US$403 million corporately held US dollar-denominated long-term debt as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged.

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

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

The Corporation and its subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest rate expense resulting from fluctuations in interest rates associated with variable rate debt for recovery from, or refund to, customers in future rates. As described in the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt facilities and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt at December 31, 2008.

Total Debt

As at December 31, 2008	*($ millions)*	*(%)*
Short-term borrowings	**410**	**7.4**
Utilized variable-rate credit facilities classified as long-term	**224**	**4.0**
Variable-rate long-term debt and capital lease obligations (including current portion)	**22**	**0.4**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**4,878**	**88.2**
Total	**5,534**	**100.0**

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps. The impact of a material change in interest rates on the fair value measurement of the interest rate swaps outstanding as at December 31, 2008 is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swaps and their near-term maturities.

The nature and fair value of the interest rate swaps outstanding as at December 31, 2008 is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates as that change would have affected 2008 financial results is disclosed in Note 26 to the 2008 Consolidated Financial Statements.

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

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to recent events in the capital markets, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. To date, the Terasen Gas companies have not experienced any counterparty defaults and they do not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: In recent years, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and increase sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to switch to an alternative fuel. See also the "Business Risk Management – Government of British Columbia's Energy Plan" and "Business Risk Management – Risks Related to TGVI" sections of this MD&A.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the US Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and incurring costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 61 per cent of the above utilities' total employees are members of such plans. The recent volatility in the global financial and capital markets is expected to affect the Corporation's consolidated future defined benefit pension funding requirements, as discussed in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A. Future pension benefit obligations and related pension expense may also be affected. The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with defined benefit pension plans is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 2 to the 2008 Consolidated Financial Statements. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense.

Market-driven changes impacting the discount rate, which is used to value the accrued pension benefit obligation as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or pension expense at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. At the Terasen Gas companies and FortisBC, however, actual pension expense above or below the forecast pension expense approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As at December 31, 2008, the balance outstanding under these loans was $61 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a progression from the previous plan with a focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. FortisBC and the Terasen Gas companies continue to assess the impacts and opportunities provided by the Energy Plan and will consider which policy actions they may support. Many of the principles of the Energy Plan were adopted when *Bill 15-2008, the Utilities Commission Amendment Act, 2008*, received Royal Assent by the Legislative Assembly of British Columbia on May 1, 2008. In addition, the *Carbon Tax Act*, which received Royal Assent by the Legislative Assembly of British Columbia on May 29, 2008, introduced a consumption tax on carbon-based fuels which impacts the competitiveness of natural gas versus non-carbon-based energy sources. The legislation did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the recent legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines, or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2008, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2008, there were no material environmental liabilities recorded in the Corporation's 2008 Consolidated Financial Statements and there were no material unrecorded environmental liabilities known to management. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators will agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

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

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation's utilities address environmental matters in their operations through the use of Environmental Management Systems ("EMS"). As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authorities to recover the loss or liability through increased customer rates. However, there can be no assurance that regulatory authorities would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' business, results of operations and financial condition. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' business, results of operations and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the financial condition and results of operations of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices at its electricity operations has related to its non-regulated energy sales in Ontario, where energy is sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will expire on April 30, 2009 and, as a result, the Corporation's exposure to market price fluctuations in Ontario will be substantially reduced and earnings related to the Niagara Exchange Agreement will cease after that date. During 2008, earnings' contribution associated with the Niagara Exchange Agreement was approximately $16 million. The Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to International Financial Reporting Standards: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). IFRS will require increased financial statement disclosure compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Fortis. The Corporation is currently assessing the impact a conversion to IFRS would have on its future financial reporting. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Corporation's consolidated earnings and balance sheet from that reported under Canadian GAAP. Information on the Corporation's IFRS conversion project is provided in the "Future Accounting Changes" section of this MD&A.

Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada before 2015. If the jurisdictions are unable to establish these treaties or agreements, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were in Canada. Conversely, if treaties or agreements can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax free. In the event that the offshore earnings become taxable, earnings' contribution from the Corporation's Caribbean Regulated Electric utilities and BECOL will decrease.

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

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

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

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by FortisAlberta's predecessor, TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual Band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 60 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and earnings of the utilities.

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

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

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

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

Changes in Accounting Standards

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

Future Accounting Changes

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

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

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

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

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

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

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to Fortis, based on existing IFRS, are rate-regulated accounting; property, plant and equipment; investment property; provisions and contingent liabilities; employee benefits; impairment of assets; income taxes; business combinations; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

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

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

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

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

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Corporation's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes and Audit Committee approval of IFRS-compliant financial statements.

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

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

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

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Corporation must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4 to the 2008 Consolidated Financial Statements, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets: Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

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

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the Corporation's consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

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

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

Financial Instruments[(1)]

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

(1) Carrying value as at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 million).

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $347 million of preference shares classified as equity was $268 million at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

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

Derivative Financial Instruments

As at December 31	2008				2007	
Asset (Liability)	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Interest Rate Swaps	**1 to 2**	**2**	**–**	**–**	–	–
Foreign Exchange Forward Contract	**<3**	**1**	**7**	**7**	–	–
Natural Gas Derivatives:						
Swaps and Options	**Up to 3**	**228**	**(84)**	**(84)**	(79)	(79)
Gas Purchase Contract Premiums	**Up to 3**	**74**	**(8)**	**(8)**	5	5

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

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

The natural gas derivatives are used to fix the effective purchase price of natural gas as the majority of the natural gas supply contracts have floating, rather than fixed, prices. At the Terasen Gas companies, changes in the fair value of interest rate swaps, the foreign exchange forward contract and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – accounts payable and accounts receivable).

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

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

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2008, Fortis recorded $360 million in current and long-term regulatory assets (December 31, 2007 – $312 million) and $446 million in current and long-term regulatory liabilities (December 31, 2007 – $392 million). The increase in regulatory assets year over year was primarily due to amounts deferred in FortisAlberta's AESO charges deferral account in 2008 and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase in regulatory liabilities year over year was largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2008 Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2008, the Corporation's consolidated utility capital assets and income producing properties were approximately $7.9 billion, or approximately 71 per cent of total consolidated assets, compared to consolidated utility capital assets and income producing properties of $7.3 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2007. The increase in capital assets was primarily associated with capital expenditures, which totalled $904 million in 2008. Amortization expense for 2008 was $348 million compared to $273 million for 2007. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2008 was $337 million (December 31, 2007 – $319 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2008 was $35 million (2007 – $33 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates as approved by the regulator. Changes in regulator-approved amortization rates at FortisAlberta and Newfoundland Power during 2008 did not have a material impact on consolidated amortization expense.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing in May 2008, Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2008, GEC totalled $57 million (2007 – $42 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recorded as operating expenses versus utility capital assets.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill and updates its review as at year end. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on $1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2008. For a discussion of the nature of the change in goodwill during 2008, refer to the "Consolidated Financial Position" section of this MD&A.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and other post-employment benefit ("OPEB") plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued pension benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rates of return on the defined benefit pension plan assets, for the purpose of estimating pension expense for 2009, range from 6.75 per cent to 7.25 per cent for the larger defined benefit pension plans. These rates compare to assumed long-term rates of return used in 2008 that ranged from 6.50 per cent to 7.50 per cent. The defined benefit pension plan assets experienced total negative returns during 2008 of approximately $92 million compared to expected positive returns of $49 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2008 and to determine pension expense for 2009 ranged from 6.00 per cent to 7.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2007 and determine pension expense for 2008 that ranged from 5.25 per cent to 5.60 per cent. The discount rates increased as a result of the impact of increased credit risk spreads on investment-grade corporate bonds due to volatility in the capital markets. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

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

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

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

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2008

Increase (decrease)	Net benefit expense		Accrued benefit asset		Accrued benefit liability		Benefit obligation	
($ millions)	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
Impact of increasing the rate of return assumption by 100 basis points	(3)	(4)	3	4	–	–	–	–
Impact of decreasing the rate of return assumption by 100 basis points	3	4	(3)	(4)	–	–	–	–
Impact of increasing the discount rate assumption by 100 basis points	–	(3)	(1)	3	(1)	–	(19)	(38)
Impact of decreasing the discount rate assumption by 100 basis points	4	6	(3)	(5)	1	–	21	46

Other assumptions applied in measuring defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the expense and related obligation. The assumptions described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan expense and obligations.

As approved by the respective regulators, FortisAlberta and Newfoundland Power record the cost of defined benefit pension and/or OPEB plan benefits on a cash basis, whereby differences between the cash payments made during the year and the expense incurred during the year are deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions cause changes in regulatory assets and liabilities for these companies and do not affect earnings. As disclosed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the Terasen Gas companies and FortisBC have regulator-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or regulatory liability.

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

Asset-Retirement Obligations: The measurement of fair value of asset-retirement obligations ("AROs") requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the systems and the remediation of certain land, there were no amounts recorded as at December 31, 2008 and 2007. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and distribution and transmission assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned, or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $365 million (December 31, 2007 – $309 million) on annual consolidated revenue of approximately $3.9 billion (2007 – $2.7 billion).

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

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

Terasen

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

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

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the 2008 Consolidated Financial Statements.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2008 Consolidated Financial Statements.

Maritime Electric

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

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

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

Exploits Partnership

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

Discussions are ongoing with Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been reclassified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2008, 2007 and 2006. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	2008	2007[(1)]	2006
Revenue and equity income	**3,903**	2,718	1,472
Net earnings	**259**	199	149
Net earnings applicable to common shares	**245**	193	147
Total assets	**11,178**	10,273	5,441
Long-term debt and capital lease obligations (net of current portion)	**4,884**	4,623	2,558
Preference shares[(2)(3)]	**667**	442	442
Common shareholders' equity	**3,046**	2,601	1,276
Basic earnings per common share	**1.56**	1.40	1.42
Diluted earnings per common share	**1.52**	1.32	1.37
Dividends declared per common share	**1.01**	0.88	0.70
Dividends declared per First Preference Share, Series C	**1.3625**	1.3625	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F[(4)]	**1.2250**	1.2250	0.5211
Dividends declared per First Preference Share, Series G[(3)]	**1.0184**	–	–

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

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

(3) A total of 9.2 million First Preference Shares, Series G were issued on May 23, 2008 and June 4, 2008 at $25.00 per share for net after-tax proceeds of $225 million and are entitled to receive cumulative dividends in the amount of $1.3125 per share per annum.

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

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

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

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2008 and 2007. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. A discussion of the financial results for the fourth quarter of 2008 is also contained in the Corporation's fourth quarter 2008 media release, dated and filed on SEDAR at www.sedar.com on February 5, 2009, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31 *(Unaudited)*	**Gas Volumes** *(TJ)* **Energy and Electricity Sales** *(GWh)*			**Revenue** *($ millions)*		
	2008	2007	Variance	**2008**	2007	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
Terasen Gas Companies	**66,816**	69,108	(2,292)	**606**	548	58
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,068**	4,002	66	**78**	68	10
FortisBC	**842**	839	3	**66**	61	5
Newfoundland Power	**1,412**	1,384	28	**139**	132	7
Other Canadian	**543**	554	(11)	**65**	66	(1)
	6,865	6,779	86	**348**	327	21
Regulated Electric Utilities – Caribbean *(GWh)*	**361**	272	89	**159**	76	83
Non-Regulated – Fortis Generation *(GWh)*	**312**	303	9	**20**	19	1
Non-Regulated – Fortis Properties				**52**	50	2
Corporate and Other				**7**	6	1
Inter-Segment Eliminations				**(10)**	(8)	(2)
Total				**1,182**	1,018	164

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

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

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

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

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 *(Unaudited)*

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

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

Summary of Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

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

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

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

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

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2007 through December 31, 2008. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Applicable to Common Shares *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2008	1,182	76	0.48	0.46
September 30, 2008	727	49	0.31	0.31
June 30, 2008	848	29	0.19	0.18
March 31, 2008	1,146	91	0.58	0.55
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35

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

Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results for the second quarter of 2008 reflected the $13 million unfavourable impact to Fortis of a charge recorded at Belize Electricity as a result of the June 2008 regulatory rate decision. Due to a shift in the quarterly distribution of annual purchased power expense at Newfoundland Power, the Company's earnings in 2008 were lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense. Financial results from August 1, 2007 were impacted by the acquisition of the Delta Regina in Saskatchewan.

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

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

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

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

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2008 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2008 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2008, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Subsequent Events

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

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

Outlook

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

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

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

Outstanding Share Data

As at March 10, 2009, the Corporation had issued and outstanding 169.8 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; and 9.2 million First Preference Shares, Series G. Only the common shares of the Corporation have voting rights.

The number of common shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E as at March 10, 2009 is as follows:

Conversion of Securities into Common Shares

As at March 10, 2009 *(Unaudited)* **Security**	**Number of Common Shares** *(millions)*
Stock Options	**4.1**
Convertible Debt	**1.8**
First Preference Shares, Series C	**6.0**
First Preference Shares, Series E	**9.7**
Total	**21.6**

Additional information, including the Fortis 2008 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2008 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2008 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for the training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review the shareholders' auditors' independence and auditors' fees. The 2008 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2008 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon the recommendation of the Audit Committee, have performed an audit of the 2008 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

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

St. John's, Canada

Auditors' Report

To the Shareholders of Fortis Inc.

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

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada,
January 30, 2009

Financials

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

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

Commitments *(Note 27)*

Contingent Liabilities *(Note 28)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Geoffrey F. Hyland,
Director

David G. Norris,
Director

Financials

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2008**	2007
Revenue	**$ 3,903**	$ 2,718
Expenses		
Energy supply costs	**2,112**	1,287
Operating	**743**	617
Amortization	**348**	273
	3,203	2,177
Operating Income	**700**	541
Finance charges *(Note 17)*	**363**	299
Gain on sale of property *(Note 18)*	**–**	(8)
	363	291
Earnings Before Corporate Taxes and Non-Controlling Interest	**337**	250
Corporate taxes *(Note 19)*	**65**	36
Net Earnings Before Non-Controlling Interest	**272**	214
Non-controlling interest	**13**	15
Net Earnings	**259**	199
Preference share dividends	**14**	6
Net Earnings Applicable to Common Shares	**$ 245**	$ 193
Earnings Per Common Share *(Note 14)*		
Basic	**$ 1.56**	$ 1.40
Diluted	**$ 1.52**	$ 1.32

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2008**	2007
Balance at Beginning of Year	**$ 551**	$ 486
Net Earnings Applicable to Common Shares	**245**	193
	796	679
Dividends on Common Shares	**(162)**	(128)
Balance at End of Year	**$ 634**	$ 551

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

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

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

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

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

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

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

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

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to mainly residential and commercial customers.

Regulated Electric Utilities – Canadian

a. *FortisAlberta*: FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta.

b. *FortisBC*: Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power*: Newfoundland Power is the principal distributor of electricity in Newfoundland. Newfoundland Power has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian*: Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

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

b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed generating capacity of 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. The impact on 2008 earnings was not material. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

c. *Fortis Turks and Caicos*: Includes P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.

b. *Ontario*: Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.

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

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

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

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

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

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

2. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP by entities not subject to rate regulation. The differences are described in Note 2 under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGVI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGVI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGVI have been extended until 2009. During 2008, the BCUC extended the PBR agreement for FortisBC for the years 2009 through 2011. Under the PBR agreement, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.62 per cent for 2008 (2007 – 8.37 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.32 per cent for 2008 (2007 – 9.07 per cent) on a deemed capital structure of 40 per cent common equity. FortisBC's allowed ROE was 9.02 per cent for 2008 (2007 – 8.77 per cent) on a deemed capital structure of 40 per cent common equity. The allowed ROE at each of TGI, TGVI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. TGI, TGVI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and/or through the operation of the PBR mechanisms.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *AUC Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under cost-of-service regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75 per cent for 2008 (2007 – 8.51 per cent) on a deemed capital structure of 37 per cent common equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost-of-service regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establish the revenue requirement upon which Newfoundland Power's customer rates are determined. Between test years, Newfoundland Power's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. Newfoundland Power's allowed ROE for 2008 was 8.95 per cent (2007 – 8.60 per cent) on a deemed capital structure of 45 per cent common equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Maritime Electric

Maritime Electric operates under a traditional cost-of-service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 10.00 per cent for 2008 (2007 – 10.25 per cent) on a deemed capital structure of 40 per cent common equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost-of-service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In 2008, the utility's electricity distribution rates were based upon costs derived from a 2004 test year using a deemed capital structure of 46.7 per cent common equity. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure over a three-year period. FortisOntario's allowed ROE was 9 per cent for 2008 (2007 – 9 per cent).

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, expiring in 2033. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. The basic electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and an allowed rate of return on rate base assets ("ROA"). Belize Electricity's allowed ROA was set at 10.00 per cent effective July 1, 2008 (2007 – 10.00 to 15.00 per cent).

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government") since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive transmission and distribution ("T&D") licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The new generation licence is for a period of 21.5 years, expiring September 2029. The new licences establish a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates are set using an initial targeted allowed ROA of 10 per cent, down from an allowed ROA of 15 per cent that was permitted under the previous licence. The new licences detail the role of the Electric Regulatory Authority, which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

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

Regulation (cont'd)

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfalls. The submissions for 2008 calculated the Allowable Operating Profit for 2008 to be $22 million (US$18 million) and the cumulative shortfall at December 31, 2008 to be $22 million (US$18 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

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

Inventories

Inventories are valued at the lower of weighted-average cost and net realizable value.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US$2.00, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2008, the long-term regulatory liability for future asset removal and site restoration costs was $337 million (December 31, 2007 – $319 million) (Note 4 *(xii)*). The Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future asset removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2008. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings when incurred, and these costs did not have a material impact on the Corporation's 2008 and 2007 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, as required by their respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2008 was approximately $31 million (2007 – $26 million).

Utility capital assets include inventories held for the development, construction and maintenance of other utility capital assets. When put into service, the inventories are amortized using the straight-line method based on estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing May 2008, Caribbean Utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2008, GEC totalled $57 million (2007 – $42 million).

As required by their respective regulators, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges and AFUDC capitalized during 2008 was $13 million (2007 – $8 million) (Note 17), including an equity component of $6 million (2007 – $3 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2008, amortization expense was reduced by $4 million (2007 – $5 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 39.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2008 was 3.5 per cent (2007 – 3.6 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

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

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of 2 years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Leases

Leases which transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

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

Intangibles

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

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

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

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2008 and 2007.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the carrying value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's carrying value, including a fair return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset-specific but are pooled for the entire regulated enterprise.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit, to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2008 and 2007.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued pension benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of the Terasen Gas companies and Newfoundland Power, pension plan assets are valued at fair value. At the Terasen Gas companies and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at the Terasen Gas companies and Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 *(viii)* and *(xvii)*).

Supplementary and Other Post-Employment Benefit ("OPEB") Plans
The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, Terasen Gas companies, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with the supplementary and OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation, at the beginning of the fiscal year, and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

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

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

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 15). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices, and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

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

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

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining and denominated in US dollars or in a currency pegged to the US dollar, are translated at the exchange rate in effect at the balance sheet dates. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00. The exchange rate in effect at December 31, 2008 was US$1.00 = CDN$1.22 (December 31, 2007 – US$1.00 = CDN$0.99). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income. Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in earnings.

Financial Instruments

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

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4 *(xvi)*). Currently, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

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

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

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

Hedging Relationships

At December 31, 2008, the Corporation's hedging relationships consisted of interest rate swap contracts, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

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

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US$55 million required to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The foreign exchange forward contract is valued at the present value of future cash flows based on published forward future foreign exchange market rate curves. Any change in the fair value of the foreign exchange forward contract is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, that the Corporation would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date. As at December 31, 2008, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The Corporation's earnings from and net investments in self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately held US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. The unrealized foreign exchange gains and losses on the US dollar-denominated long-term debt and the partially offsetting unrealized foreign exchange losses and gains on the foreign net investments are recognized in other comprehensive income.

Income Taxes

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the cash taxes payable method of accounting for income taxes, as prescribed by their respective regulators. Under this methodology, except for certain deferred accounts specifically prescribed by the respective regulators, current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable.

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

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

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

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of gas by the Terasen Gas companies and electricity by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 *(xiii)*).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. At the Corporation's other regulated utilities, transmission revenue and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected, or refunded, in future customer rates (Note 4 *(iii)*).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these costs and revenue associated with the recovery of these costs are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generation stations is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue. The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs, including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified with respect to the Corporation's hydroelectric generation and transmission and distribution assets. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Capital Disclosures

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

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

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

3. Future Accounting Changes (cont'd)

Rate-Regulated Operations

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

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

Effective January 1, 2009, with the removal of the temporary exemption from Section 1100, the Corporation must now apply Section 1100 for the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. All assets and liabilities arising from rate regulation described in Note 4 do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption from Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of $234 million, a reduction in utility capital assets of $232 million and a reduction in deferred charges and other assets of $2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

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

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

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

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

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

Regulatory Assets

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

Regulatory Liabilities

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

Description of the Nature of Regulatory Assets and Liabilities

(i) *Rate Stabilization Accounts – Terasen Gas Companies*
The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility.

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

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

At TGI, a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of TGI's natural gas commodity swaps.

At TGVI, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in the fair value of TGVI's natural gas commodity swaps. TGVI also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed the allowed ROE as set by the BCUC. During 2008 and 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be refunded through rates over a three-year period, with a total balance outstanding as at December 31, 2008 of $8 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered, or refunded, within the next fiscal year. In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recorded in earnings as incurred. The recovery or refund of amounts in the rate stabilization accounts is dependent on actual natural gas consumption volumes and on annually approved customer rates.

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

(ii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered, or refunded, through customer rates as approved by the respective regulatory authorities. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, whose recovery period is not determinable, ranges from one year to five years and is subject to periodic review by the respective regulators.

As at December 31, 2008, the balance in Belize Electricity's rate stabilization account was in a payable position, as compared to a receivable position as at December 31, 2007. During the second quarter of 2008, a downward $18 million adjustment was made to Belize Electricity's cost of power rate stabilization account reflecting, in substance, the disallowance of previously incurred fuel and purchased power costs as a result of the Final Decision by the PUC on Belize Electricity's 2008/2009 rate application.

The balance in Newfoundland Power's weather normalization account should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately $7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recorded in earnings in the period in which they occurred. The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

As at December 31, 2008, $12 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of six years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling eight-month period.

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

(iii) *AESO Charges Deferral*

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

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

(iv) *Regulatory OPEB Plan Asset*

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by the respective regulators. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of OPEB plans. The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta's and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(v) *Income Taxes Recoverable on OPEB Plans*

At TGI, the regulator allows OPEB plan costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. Since TGI accounts for income taxes using the cash taxes payable method, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(vi) *Deferred Capital Asset Amortization*

Newfoundland Power deferred the recovery of a $6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The approximate $12 million balance at December 31, 2007 is being amortized as an increase in amortization costs and included in customer rates equally over 2008 through 2010. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(vii) *Residential Unbundling*

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

(viii) *Deferred Pension Costs*

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

(ix) *Southern Crossing Pipeline Tax Reassessment*

The Southern Crossing Pipeline tax-reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. In 2006, the Company made a payment of $10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to $7 million and the overpayment was refunded to TGI. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable pending resolution of the appeal. Any final assessed tax, upon resolution of the appeal, would be expensed in the period in which it becomes known (Note 28).

(x) *Energy Management Costs*

FortisBC provides energy management services to promote energy efficiency programs to its customers. As required by a BCUC order, the Company has capitalized related expenditures and is amortizing these expenditures on a straight-line basis over eight years. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(xi) *Other Regulatory Assets*

Other regulatory assets primarily relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Maritime Electric and Caribbean Utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2008, $32 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2008, $7 million (December 31, 2007 – $9 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

4. Regulatory Assets and Liabilities (cont'd)

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

(xii) Future Asset Removal and Site Restoration Provision

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to asset removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for these future asset removal and site restoration costs, net of salvage proceeds. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

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

During 2008, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was $35 million (2007 – $33 million). During 2008, actual asset removal and site restoration costs, net of salvage proceeds, were $21 million (2007 – $19 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xiii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 2). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the PUB. As a result, the $24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized $7 million of this regulatory liability in 2008 (2007 – $3 million). The remaining balance as at December 31, 2008 will be amortized by approximately $5 million in each of 2009 and 2010. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted. Belize Electricity's unbilled revenue liability of $6 million as at December 31, 2008 (December 31, 2007 – $5 million) is not subject to a regulatory return.

(xiv) PBR Incentive Liabilities

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders (Note 2). TGI's regulatory PBR incentive liability of $11 million is expected to be refunded to customers through reduced rates in 2009. Based on the current PBR framework, FortisBC's 2008 regulatory PBR incentive liability of $2 million has been approved by the BCUC for settlement in 2009 through a reduction in 2009 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xv) Southern Crossing Pipeline Deferral

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing Pipeline and what has been approved in revenue requirements. The balance is amortized over five years. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xvi) Fair Value of the Foreign Exchange Forward Contract

This regulatory liability captures the change in the fair value of the foreign exchange forward contract, which hedges the US dollar payments required under the LNG construction contract. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings. This regulatory deferral is not subject to a regulatory return.

(xvii) Pension Deferral

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

(xviii) Other Regulatory Liabilities

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2008, $17 million of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2008, $2 million (December 31, 2007 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

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

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

5. Inventories

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

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

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

6. Deferred Charges and Other Assets

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

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

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

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

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

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

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

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

7. Utility Capital Assets

2008 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Regulatory Tax Basis Adjustment (Net)**	**Net Book Value**
Distribution					
Gas	**$ 2,426**	**$ (495)**	**$ (180)**	**$ –**	**$ 1,751**
Electricity	**3,948**	**(1,042)**	**(490)**	**(87)**	**2,329**
Transmission					
Gas	**1,304**	**(316)**	**(100)**	**–**	**888**
Electricity	**970**	**(252)**	**(2)**	**–**	**716**
Generation	**971**	**(280)**	**(1)**	**–**	**690**
Assets under construction	**317**	**–**	**(11)**	**–**	**306**
Other	**1,090**	**(390)**	**(13)**	**–**	**687**
	$ 11,026	**$ (2,775)**	**$ (797)**	**$ (87)**	**$ 7,367**

2007 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	$ 2,233	$ (364)	$ (174)	$ –	$ 1,695
Electricity	3,542	(961)	(463)	(91)	2,027
Transmission					
Gas	1,277	(286)	(102)	–	889
Electricity	873	(224)	–	–	649
Generation	914	(240)	–	–	674
Assets under construction	195	–	–	–	195
Other	970	(337)	(14)	–	619
	$ 10,004	$ (2,412)	$ (753)	$ (91)	$ 6,748

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires and conductors, substations, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

The cost of utility capital assets under capital lease as at December 31, 2008 was $56 million (December 31, 2007 – $51 million) and related accumulated amortization was $24 million (December 31, 2007 – $19 million).

8. Income Producing Properties

2008

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

2007

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

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

9. Goodwill

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

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

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

10. Long-Term Debt and Capital Lease Obligations

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

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

Certain of the long-term debt instruments held by the Corporation and its subsidiaries are secured as identified in the table above. When security is provided, it is typically a fixed or floating charge on the specific assets of the company to which the long-term debt is associated.

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

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

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

Regulated Utilities

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

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

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

Corporate – Fortis and Terasen

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

The unsecured subordinated convertible debentures, due 2016, are redeemable by Fortis at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's common shares at $35.46 per share (US$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the consolidated balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was $6 million as at December 31, 2008 (December 31, 2007 – $6 million).

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

11. Deferred Credits

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

The deferred gains on the sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 27.

The deferred payment resulted from Terasen's acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of $52 million but was discounted at May 17, 2007 to its present value. At December 31, 2008, its present value was $43 million (December 31, 2007 – $40 million). The payment is due on December 31, 2011 or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants that may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

Other deferred credits primarily include customer deposits, DSU and PSU liabilities and unfunded defined contribution pension liabilities.

12. Non-Controlling Interest

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

13. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value

(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		2008		2007	
	Classification	Number of Shares	Amount *(in millions)*	Number of Shares	Amount *(in millions)*
First Preference Shares, Series C	Debt	5,000,000	$ 123	5,000,000	$ 123
First Preference Shares, Series E	Debt	7,993,500	197	7,993,500	197
Total classified as debt		12,993,500	$ 320	12,993,500	$ 320
First Preference Shares, Series F	Equity	5,000,000	$ 122	5,000,000	$ 122
First Preference Shares, Series G	Equity	9,200,000	225	–	–
Total classified as equity		14,200,000	$ 347	5,000,000	$ 122

First Preference Shares Classified as Debt

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

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

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

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradable common shares of the Corporation. The number of common shares into which each preference share may be so converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 and 95 per cent of the then-current market price of the common shares at such time.

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradable common shares of the Corporation determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 and 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series C and Series E elects to convert any of such shares into common shares, the Corporation can redeem such first preference shares for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares Classified as Equity

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

As the First Preference Shares, Series F and Series G are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings immediately before arriving at net earnings applicable to common shares.

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

13. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

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

14. Common Shares

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

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

Common shares issued during the year were as follows:

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

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

During 2008, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US$11 million of the debentures into approximately 1.0 million common shares of the Corporation.

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

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

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

As at December 31, 2008, 9.8 million (December 31, 2007 – 6.2 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. During 2008, an additional 5 million common shares were reserved under the dividend reinvestment plan in accordance with an enhancement made to the plan. The Corporation amended and restated its dividend reinvestment plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2008, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26 million, respectively (December 31, 2007 – 2.4 million and 26 million, respectively).

As at December 31, 2008, $3 million (December 31, 2007 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 157.4 million for 2008 and 137.6 million for 2007.

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

Earnings per common share are as follows:

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

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

15. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2008, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

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

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

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

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

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

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

In February 2008, the Corporation granted 827,504 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $28.27 immediately preceding the date of grant. The fair value of each option granted was $4.76 per option.

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

Dividend yield *(%)*	2.90
Expected volatility *(%)*	20.7
Risk-free interest rate *(%)*	3.92
Weighted average expected life *(years)*	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $3 million for the year ended December 31, 2008 (2007 – $2 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit for their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Number of DSUs:	2008	2007
DSUs outstanding, beginning of year	**69,722**	46,959
Granted	**27,224**	20,859
Granted – notional dividends reinvested	**3,671**	1,904
DSUs outstanding, end of year	**100,617**	69,722

For the year ended December 31, 2008, expense of $0.2 million (2007 – $0.8 million) was recorded in relation to the DSU Plan.

PSU Plan

In 2004, the Corporation introduced the PSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

Number of PSUs:	2008	2007
PSUs outstanding, beginning of year	**67,615**	66,845
Granted	**32,940**	19,570
Granted – notional dividends reinvested	**3,011**	1,883
PSUs paid out	**(18,019)**	(20,683)
PSUs outstanding, end of year	**85,547**	67,615

In March 2008, 18,019 PSUs were paid out to the President and CEO of the Corporation at $28.36 per PSU for a total of approximately $0.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2005, and the President and CEO satisfying the payment requirements as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2008, expense of $0.6 million (2007 – $0.6 million) was recorded in relation to the PSU Plan.

16. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2008		
(in millions)	Opening balance January 1	Net change	**Ending balance December 31**
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**$ (82)**	**$ 36**	**$ (46)**
Losses on derivative instruments designated as cash flow hedges, net of tax	**(1)**	**–**	**(1)**
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	**(5)**	**–**	**(5)**
Accumulated other comprehensive loss	**$ (88)**	**$ 36**	**$ (52)**

	2007			
(in millions)	Opening balance January 1	Transition amount January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	$ (51)	$ –	$ (31)	$ (82)
Losses on derivative instruments designated as cash flow hedges, net of tax	–	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	–	(5)	–	(5)
Accumulated other comprehensive loss	$ (51)	$ (6)	$ (31)	$ (88)

16. Accumulated Other Comprehensive Loss (cont'd)

During 2008, unrealized foreign currency translation gains of $115 million (2007 – losses of $70 million) were recorded in accumulated other comprehensive loss related to the Corporation's net investment in foreign currency-denominated self-sustaining foreign operations. These unrealized foreign currency translation gains were partially offset by the effective portion of unrealized after-tax losses of $79 million (2007 – after-tax gains of $39 million) related to the translation of corporately held US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

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

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

17. Finance Charges

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

18. Gain on Sale of Property

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

19. Corporate Taxes

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory tax rate to earnings before corporate taxes and non-controlling interest. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

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

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

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

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

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

19. Corporate Taxes (cont'd)

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

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

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

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension arrangements, the accrued pension benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, Terasen Gas companies, Newfoundland Power and Caribbean Utilities commencing December 2008 (2007 – measured as at April 30), and as at September 30 of each year for FortisAlberta, FortisBC and FortisOntario. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2007 for FortisAlberta and FortisBC; as of December 31, 2006 for FortisOntario; as of December 31, 2005 for the Corporation and Newfoundland Power; and as of December 31, 2008 for Caribbean Utilities. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2005 and December 31, 2007. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company.

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

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

Plan assets as at December 31

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

Notes to Consolidated Financial Statements

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

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

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

20. Employee Future Benefits (cont'd)

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

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

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	**$ 22**	**$ (16)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

Increase (Decrease) (in millions)	Net Benefit Expense	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation
Impact of increasing the rate of return assumption by 100 basis points	$ (7)	$ 7	$ –	$ –
Impact of decreasing the rate of return assumption by 100 basis points	7	(7)	–	–
Impact of increasing the discount rate assumption by 100 basis points	(3)	2	(1)	(57)
Impact of decreasing the discount rate assumption by 100 basis points	10	(8)	1	67

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

21. Business Acquisitions

2008

Fairmont Newfoundland Hotel

In November 2008, Fortis Properties purchased the Fairmont Newfoundland hotel for an aggregate cash purchase price of approximately $22 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing November 2008.

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

(in millions)	**Total**
Fair value assigned to net assets:	
Income producing properties	**$ 22**

2007

a. Terasen

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

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

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, Terasen's 30 per cent investment in non-regulated CWLP and Terasen's 100 per cent investment in non-regulated TES have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The determination of revenue and earnings is based on regulated rates of return that are applied to historic values which do not change with a change of ownership. Therefore, for substantially all of the individual assets and liabilities associated with the Terasen Gas companies, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation are related to non-regulated Terasen and its non-regulated investments.

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

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

21. Business Acquisitions (cont'd)

a. Terasen (cont'd)

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

b. Delta Regina

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

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

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

(in millions)	Total
Fair value assigned to net assets:	
Income producing properties	$ 50

22. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2008 *($ millions)*	**Terasen Gas Companies – Canadian**[(1)]	Fortis Alberta	Fortis BC	NF Power	Other Canadian[(2)]	**Total Electric Canadian**	**Electric Caribbean**[(3)]	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	1,902	300	237	517	262	1,316	408	82	207	26	(38)	3,903
Energy supply costs	1,268	–	68	337	177	582	273	7	–	–	(18)	2,112
Operating expenses	253	130	67	50	28	275	55	14	135	16	(5)	743
Amortization	97	85	34	45	18	182	36	10	15	8	–	348
Operating income	284	85	68	85	39	277	44	51	57	2	(15)	700
Finance charges	129	42	28	33	18	121	16	8	24	80	(15)	363
Corporate taxes (recoveries)	37	(3)	6	19	7	29	2	10	10	(23)	–	65
Non-controlling interest	–	–	–	1	–	1	9	3	–	–	–	13
Net earnings (loss)	118	46	34	32	14	126	17	30	23	(55)	–	259
Preference share dividends	–	–	–	–	–	–	–	–	–	14	–	14
Net earnings (loss) applicable to common shares	118	46	34	32	14	126	17	30	23	(69)	–	245
Goodwill	903	227	221	–	63	511	161	–	–	–	–	1,575
Identifiable assets	3,721	1,574	990	1,001	520	4,085	867	285	559	126	(40)	9,603
Total assets	4,624	1,801	1,211	1,001	583	4,596	1,028	285	559	126	(40)	11,178
Gross capital expenditures	220	302	117	67	46	532	110	19	14	9	–	904
Year ended December 31, 2007 *($ millions)*												
Revenue	905	270	229	491	263	1,253	307	75	191	22	(35)	2,718
Energy supply costs	559	–	67	327	174	568	169	8	–	–	(17)	1,287
Operating expenses	150	122	69	53	29	273	49	14	123	13	(5)	617
Amortization	58	75	31	34	17	157	28	10	14	6	–	273
Operating income	138	73	62	77	43	255	61	43	54	3	(13)	541
Finance charges	80	36	26	34	17	113	15	10	24	70	(13)	299
Gain on sale of property	(8)	–	–	–	–	–	–	–	–	–	–	(8)
Corporate taxes (recoveries)	16	(11)	5	12	10	16	2	8	6	(12)	–	36
Non-controlling interest	–	–	–	1	–	1	13	1	–	–	–	15
Net earnings (loss)	50	48	31	30	16	125	31	24	24	(55)	–	199
Preference share dividends	–	–	–	–	–	–	–	–	–	6	–	6
Net earnings (loss) applicable to common shares	50	48	31	30	16	125	31	24	24	(61)	–	193
Goodwill	907	227	221	–	63	511	126	–	–	–	–	1,544
Identifiable assets	3,540	1,294	914	986	484	3,678	652	235	535	108	(19)	8,729
Total assets	4,447	1,521	1,135	986	547	4,189	778	235	535	108	(19)	10,273
Gross capital expenditures	120	285	147	72	38	542	106	17	13	5	–	803

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

22. Segmented Information (cont'd)

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31 were as follows:

(in millions)	**2008**	2007
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	**$ 17**	$ 15
Sales from Fortis Generation to Other Canadian Electric Utilities	**1**	1
Sales from Newfoundland Power to Fortis Properties	**4**	4
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	**2**	2
Corporate to Regulated Electric Utilities – Caribbean	**5**	1
Corporate to Fortis Properties	**8**	8

23. Supplementary Information to Consolidated Statements of Cash Flows

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

24. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital in order to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings.

Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates. Fortis generally finances a significant portion of acquisitions with proceeds from common and preference share issuances.

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

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

[(1)] Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash

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

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at December 31, 2008, the Corporation and its subsidiaries, except for Belize Electricity and the Exploits Partnership as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 rate application, Belize Electricity does not meet certain debt covenant financial ratios related to loans totalling $11 million (BZ$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

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

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

25. Financial Instruments

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

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

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
(2) Included in accounts receivable on the balance sheet
(3) Carrying value approximates amortized cost
(4) Included in deferred charges and other assets on the balance sheet
(5) Included in accounts payable and accrued charges on the balance sheet
(6) Included in deferred credits on the balance sheet
(7) Carrying value is measured at amortized cost using the effective interest rate method.
(8) Carrying value at December 31, 2008 is net of unamortized deferred financing costs of $34 million (December 31, 2007 – $33 million).
(9) Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's $347 million preference shares classified as equity was $268 million as at December 31, 2008 (December 31, 2007 – carrying value $122 million; fair value $107 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices, when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

	2008				2007	
Asset (Liability)	Term to Maturity *(years)*	Number of Contracts	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Interest rate swaps[(1)]	1 to 2	2	$ –	$ –	$ –	$ –
Foreign exchange forward contract	< 3	1	7	7	–	–
Natural gas derivatives:[(2)]						
Swaps and options	Up to 3	228	(84)	(84)	(79)	(79)
Gas purchase contract premiums	Up to 3	74	(8)	(8)	5	5

(1) Interest rate swap contracts mature in July 2009 and October 2010. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 6.16 per cent and 5.32 per cent, respectively.
(2) The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – in accounts payable and accounts receivable).

25. Financial Instruments (cont'd)

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

26. Financial Risk Management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk — Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk — Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk — Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to the following market risks:

- Foreign exchange risk
- Interest rate risk
- Commodity price risk

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits and credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution-service billings being to a relatively small group of retailers and, as at December 31, 2008, its gross credit risk exposure was approximately $87 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The aging analysis of the Corporation's consolidated trade and other accounts receivable is as follows:

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

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

Liquidity Risk

The Corporation's financial position could be adversely affected if it, or its operating subsidiaries, fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

Committed credit facilities at Fortis are available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average consolidated annual long-term debt maturities and repayments are expected to be approximately $180 million. The combination of available credit facilities and low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing and access to capital markets.

As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of $2.2 billion, of which $1.5 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks with no one bank holding more than 25 per cent of these facilities.

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

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2008**	Total as at December 31, 2007
Total credit facilities	$ 715	$ 1,500	$ 13	**$ 2,228**	$ 2,234
Credit facilities utilized:					
Short-term borrowings	–	(410)	–	**(410)**	(475)
Long-term debt *(Note 10)*[(1)]	(32)	(192)	–	**(224)**	(530)
Letters of credit outstanding	(1)	(102)	(1)	**(104)**	(159)
Credit facilities available	$ 682	$ 796	$ 12	**$ 1,490**	$ 1,070

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

As at December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and its subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

Terasen Inc. has a $100 million unsecured committed revolving credit facility, maturing May 2009, that is available for general corporate purposes. Letters of credit of $50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

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

Regulated Utilities

TGI has a $500 million unsecured committed revolving credit facility, maturing August 2013. TGVI has a $350 million unsecured committed revolving credit facility, maturing January 2011. The facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also has a $20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a $200 million unsecured committed revolving credit facility, maturing May 2012, utilized to finance capital expenditures and for general corporate purposes and, with the consent of the lenders, the amount of the facility can be increased to $250 million. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC has a $150 million unsecured committed revolving credit facility of which $50 million matures May 2011 and the remaining $100 million matures May 2009. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a $10 million unsecured demand facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2011, and a $20 million uncommitted demand facility.

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

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

26. Financial Risk Management (cont'd)

Regulated Utilities (cont'd)

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

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

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

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

Fortis Properties

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

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

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

The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

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

Financial Liabilities

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

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

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. The Belizean dollar is pegged to the US dollar at BZ$2.00 = US$1.00.

As at December 31, 2008, all of the Corporation's corporately held US$403 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2008, the Corporation had approximately US$119 million in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

A 5 per cent appreciation of the US dollar relative to the Canadian dollar would have increased earnings by $0.6 million for the year ended December 31, 2008 and would have decreased other comprehensive income by $25 million for the year ended December 31, 2008. This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense and earnings' streams from the Corporation's foreign subsidiaries and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5 per cent appreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased other comprehensive income by $32 million for the year ended December 31, 2008.

TGVI's US dollar payments under a contract for the construction of an LNG storage facility exposes TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI has entered into a foreign exchange forward contract to hedge this exposure. At December 31, 2008, a 5 per cent appeciation of the US dollar relative to the Canadian dollar, as it affects the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased earnings by $3 million for the year ended December 31, 2008. Furthermore, TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than other comprehensive income.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk and, during 2008, the Terasen Gas companies and Fortis Properties were parties to interest rate swap agreements that effectively fixed the interest rates on their variable-rate borrowings. During the fourth quarter of 2008, the Terasen Gas companies' interest rate swaps matured. A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $5 million for the year ended December 31, 2008. Furthermore, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund to, customers in future rates.

As at December 31, 2008, a 100 basis point increase in interest rates as it affects the measurement of fair value of the interest rate swap agreements would have increased other comprehensive income by $0.1 million during the year ended December 31, 2008.

In addition, certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by $0.9 million for the year ended December 31, 2008.

Commodity Price Risk

The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have increased and, in the absence of rate regulation, other comprehensive income would have increased by $54 million for the year ended December 31, 2008. However, the Terasen Gas companies defer any changes in fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $54 million.

27. Commitments

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

(1) Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.

(2) Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

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

(4) Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. The contracts total approximately $72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.

(5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's commitments table above.

(6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

(7) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

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

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

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by customer requests and by large capital projects specifically approved by their respective regulatory authorities. The consolidated capital program of the Corporation, including non-regulated segments, is forecasted to be approximately $1 billion for 2009. This commitment has not been included in the commitments table above.

In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and are subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates.

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

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

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

28. Contingent Liabilities

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

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

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately $37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to $7 million, including interest, which has been paid in full to avoid accruing further interest and it is recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia (Note 4 *(ix)*).

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

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

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

Maritime Electric

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

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately $13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately $6 million.

FortisUS Energy

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

Exploits Partnership

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

Discussions are ongoing with the Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of $2 million and utility capital assets of $61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the $61 million term loan has been classified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

29. Subsequent Events

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

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

30. Comparative Figures

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

Historical Financial Summary

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

(1) As at December 31, 2006, the regulatory provision for future asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a $306.5 million (December 31, 2005 – $280.9 million) increase in long-term regulatory liabilities and a $306.5 million (December 31, 2005 – $280.9 million) increase in net utility capital assets.

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

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

Board of Directors

Geoffrey F. Hyland ∗⋆✷ *Chair, Fortis Inc., Caledon, ON*
Mr. Hyland, 64, joined the Fortis Inc. Board in May 2001 and was appointed Chair of the Board in May 2008. He retired as President and CEO of Shawcor Ltd. in June 2005 after 37 years of service. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of Enerflex Systems Income Fund, SCITI Total Return Trust and Exco Technologies Limited.

Peter E. Case ∗ *Corporate Director, Freelton, ON*
Mr. Case, 54, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, Bahamas*
Mr. Crothers, 64, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited and serves on the Board of Belize Electricity. Mr. Crothers also serves as a Director of Franklin Templeton Resources, Talon Metals Corp, Fidelity Merchant Bank & Trust (Cayman) Limited and Victory Nickel Inc.

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

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*
Mr. Marshall, 58, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ∗⋆ *Professor of Finance, University of Manitoba, Winnipeg, MB*
Mr. McCallum, 65, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters ⋆ *Wine Consultant, Summerland, BC*
Mr. McWatters, 63, joined the Fortis Inc. Board in May 2007. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Harry McWatters Inc., Vintage Consulting Group Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

David G. Norris ∗✷ *Corporate Director, St. John's, NL*
Mr. Norris, 61, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey ∗ *Corporate Director, Moncton, NB*
Mr. Pavey, 61, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ⋆✷ *Corporate Director, Halifax, NS*
Mr. Rideout, 61, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of the Halifax International Airport Authority and NAV CANADA.

∗ Audit Committee
⋆ Governance and Nominating Committee
✷ Human Resources Committee

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

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

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F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Expected Dividend* and Earnings Dates

Dividend Record Dates
May 8, 2009 | August 7, 2009
November 6, 2009 | February 5, 2010

Dividend Payment Dates
June 1, 2009 | September 1, 2009
December 1, 2009 | March 1, 2010

Earnings Release Dates
April 30, 2009 | August 5, 2009
November 5, 2009 | February 4, 2010

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

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.PR.G, respectively.

Valuation Day

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

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

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 5, 2009
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

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Colour, St. John's, NL
www.colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group,
Ottawa, ON

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Delivering long-term value for customers and shareholders.