FORTIS INC.

FOR IMMEDIATE RELEASE
St. John's, NL (February 9, 2012):

Fortis Earns $318 Million in 2011
Delivers Record Earnings for 12th Consecutive Year
Completes Record $1.2 Billion Annual Capital Program

Fortis Inc. ("Fortis" or the "Corporation") (TSX:FTS) achieved net earnings attributable to common equity shareholders of $318 million, or $1.75 per common share, up $33 million, or $0.10 per common share, compared to $285 million, or $1.65 per common share, for 2010.

Increased investment in energy infrastructure at the utilities in western Canada and the $11 million after-tax, or $0.06 per common share, fee paid to Fortis in July 2011, following the termination of the Merger Agreement with Central Vermont Public Service Corporation, were the primary drivers of earnings growth.

Fortis increased its quarterly common share dividend to 30 cents from 29 cents, commencing with the first quarter dividend payable on March 1, 2012, which translates into an annualized dividend of $1.20. Fortis has raised its annualized dividend to common shareholders for 39 consecutive years, the record for a public corporation in Canada. The dividend payout ratio was 66% in 2011.

"Our annual capital expenditure program totalled a record $1.2 billion in 2011," says Stan Marshall, President and Chief Executive Officer, Fortis Inc. "The significant investment in energy infrastructure being made by our utilities should help ensure we continue to meet our obligation to serve customers," he adds.

The largest capital projects recently completed were the $212 million 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island and the $110 million Customer Care Enhancement Project, including two new call centres, at FortisBC's gas utility; the $105 million Okanagan Transmission Reinforcement Project at FortisBC Electric; and the $126 million Automated Metering Project at FortisAlberta. Construction of the $900 million 335-megawatt Waneta Expansion hydroelectric generation facility in British Columbia, which is scheduled to be completed in spring 2015, is progressing on time and on budget, with approximately $244 million invested in the project since construction began in late 2010.

Canadian Regulated Gas Utilities delivered earnings of $139 million, up $9 million from $130 million for 2010. Excluding a favourable one-time $4 million item in 2010, earnings increased $13 million year over year. Results for 2011 reflected the impact of growth in energy infrastructure investment, lower-than-expected corporate income taxes, finance charges and amortization costs, and increased gas transportation volumes to the forestry and mining sectors, partially offset by lower-than-expected customer additions.

"The majority of our gas customers have benefited from the downward trend in natural gas commodity prices," says Marshall. "The improving supply and cost fundamentals of natural gas throughout North America, combined with its positive environmental attributes, make natural gas an attractive energy supply source for residential and industrial use and as a fuel for the transportation and power generation sectors," he explains.

Canadian Regulated Electric Utilities contributed earnings of $179 million, up $15 million from $164 million for 2010. The increase was driven by improved results at FortisAlberta and FortisBC Electric. The increase in earnings at FortisAlberta mainly resulted from growth in energy infrastructure investment, higher capitalized allowance for funds used during construction ("AFUDC"), customer growth and higher energy deliveries, and return earned on additional investment in automated meters, as approved by the regulator, partially offset by a lower allowed rate of return on common shareholders' equity ("ROE") for 2011. The increase in earnings at FortisBC Electric resulted from growth in energy infrastructure investment, lower purchased power costs and higher electricity sales, partially offset by lower capitalized AFUDC.

“FortisAlberta continues to invest significant capital in its electricity network, which includes more than 100,000 kilometres of distribution lines, with over $400 million of capital expenditures in 2011 and a similar amount planned for 2012”, says Marshall. “A significant portion of the utility’s franchise territory overlaps with the tight oil and shale gas developments in Alberta, especially the Bakken, Cardium and Duvernay areas, and our business is benefiting from building the electricity infrastructure necessary to meet associated customer growth,” he explains.

Significant regulatory processes recently decided or underway at the Corporation’s largest utilities are as follows:

- The Alberta Utilities Commission (“AUC”) issued a decision in December 2011 setting the 2011 allowed ROE for utilities in Alberta at 8.75%, down from 9.00% for 2010. The decision was recorded on a retroactive basis in the fourth quarter of 2011 and reduced FortisAlberta’s earnings by approximately $2 million in 2011.

- At FortisAlberta, a decision on customer rates for 2012 is expected during the first half of 2012. Interim rates have been approved for the utility.

- FortisAlberta filed its performance-based regulation (“PBR”) proposal in July 2011, following the AUC’s initiative to apply PBR to all distribution utilities in Alberta as early as 2013 for a five-year term. The AUC’s decision on PBR is expected in 2012.

- Newfoundland Power received regulatory approval in December 2011 to suspend the use of the ROE automatic adjustment formula for 2012, pending an expected review of the utility’s cost of capital in 2012. Customer rates for 2012 have been set on an interim basis using the 2011 allowed ROE of 8.38%.

- The allowed ROEs for the FortisBC gas and electric utilities are to be maintained, pending determinations made in the regulator-initiated Generic Cost of Capital Proceeding expected to occur in early 2012.

- Decisions on customer gas and electricity rates for 2012 and 2013 at FortisBC are expected during 2012. Interim rates have been approved for the utilities.

Caribbean Regulated Electric Utilities contributed $20 million to earnings compared to $23 million for 2010. There was no earnings contribution from Belize Electricity in 2011 due to the expropriation of the Corporation’s investment in the utility in June by the Government of Belize (“GOB”). Earnings contribution from Belize Electricity during 2010 was approximately $1.5 million. Fortis submitted its claim for compensation to the GOB in November. Earnings at Fortis Turks and Caicos decreased year over year, due to higher amortization costs and operating expenses, partially offset by reduced energy supply costs in 2011 reflecting the use of new, more fuel-efficient generating units. There was no growth in electricity sales year over year at Caribbean Utilities and Fortis Turks and Caicos, due to challenging economic conditions in the region and high fuel prices.

Non-Regulated Fortis Generation contributed $18 million to earnings compared to $20 million for 2010. The decline in earnings resulted from decreased hydroelectric production in Belize, due to lower rainfall associated with a longer dry season in 2011, combined with overall lower interest income.

Fortis Properties delivered earnings of $23 million compared to $26 million for 2010. However, results for 2010 were favourably impacted by lower corporate income tax rates, which reduced future income taxes. Results for 2011 reflected lower contribution from the Hospitality Division, driven by lower occupancy at the Company’s hotels in western Canada. Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for $25 million in October 2011.

Corporate and other expenses were $61 million, $17 million lower than $78 million for 2010. Excluding the $11 million after-tax termination fee, corporate and other expenses were $6 million lower year over year, as a result of both decreased business development costs and finance charges.

Earnings for the fourth quarter were $86 million, or $0.46 per common share, compared to $85 million, or $0.49 per common share, for the same quarter in 2010. Increased earnings at the FortisBC gas utilities, largely due to the same reasons described above for the improvement in annual earnings, were partially offset by a decrease in earnings at Newfoundland Power, Other Canadian Regulated Electric Utilities, Fortis Turks and Caicos and Fortis Properties. The decrease in earnings at Newfoundland Power reflected a lower allowed ROE and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011. Lower earnings at Other Canadian Regulated Electric Utilities were due to decreased electricity sales and higher operating expenses. Lower earnings at Fortis Turks and Caicos were due to the same reasons described above for the decrease in annual earnings. Earnings at Fortis Properties during the fourth quarter of 2010 reflected lower corporate income tax rates, which reduced future income taxes in that period. An 8% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the public common equity offering in mid-2011, had the impact of decreasing earnings per common share.

Fortis and its regulated utilities raised $688 million of long-term capital in 2011. Fortis issued approximately 10.3 million common shares for $341 million, the proceeds of which were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion Limited Partnership, in support of infrastructure investment, and for general corporate purposes. Consolidated long-term debt totalling $347 million was issued in 2011 at terms ranging from 15 to 50 years and at rates ranging from 4.25% to 5.118%. In December FortisBC's largest gas utility issued 30-year $100 million 4.25% unsecured debentures, Maritime Electric issued 50-year 4.915% $30 million first mortgage bonds and FortisOntario issued 30-year $52 million 5.118% unsecured notes. Generally, proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to finance future capital spending and for general corporate purposes. In the case of FortisOntario, the debt proceeds were used to repay an inter-company loan with Fortis, originally incurred to support the acquisition of Algoma Power in 2009.

The Corporation's US$40 million convertible debentures were converted into 1.4 million common shares at US$29.11 per share in November 2011.

Newfoundland Power received $46 million of proceeds in October 2011 upon the sale to Bell Aliant Inc. of 40% of all joint-use poles owned by Newfoundland Power.

DBRS confirmed the Corporation's debt credit rating at A(low) in September 2011. Standard and Poor's ("S&P") is expected to complete its annual review of the Corporation's debt credit rating in the first quarter of 2012. S&P currently rates the Corporation's debt at A-.

Cash flow from operating activities was $904 million for 2011, up $172 million from $732 million for 2010, driven by favourable working capital changes and higher earnings.

"We are focused on completing our $1.3 billion capital expenditure program for 2012," says Marshall. "Over the next five years through 2016, our capital expenditure program is projected to total $5.5 billion, which should support continuing growth in earnings and dividends," he adds.

"We remain disciplined and patient in our pursuit of electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders," concludes Marshall.

Financial Highlights

For the three and twelve months ended December 31, 2011
Dated February 9, 2012

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FORWARD-LOOKING STATEMENT

The following fourth quarter 2011 media release should be read in conjunction with the Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") and audited consolidated financial statements for the year ended December 31, 2010 included in the Corporation's 2010 Annual Report. Financial information in this material has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in this fourth quarter 2011 media release 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 this fourth quarter 2011 media release includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and of receipt of regulatory decisions; consolidated forecast gross capital expenditures for 2012 and in total over the five-year period 2012 through 2016; the expectation that the Corporation's significant capital expenditure program should drive growth in earnings and dividends; and the expected impact of the transition to US generally accepted accounting principles. 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 expectation that the Corporation will receive compensation from the Government of Belize ("GOB") for the fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no material capital project and financing cost overrun related to the construction of the Waneta hydroelectric generation expansion project; no significant decline in capital spending; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel 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 and fuel supply; the continuation of and/or regulatory approval of power supply and capacity purchase contracts; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; maintenance of information technology infrastructure; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the consolidated 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; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; capital project budget *overrun, completion and financing risk in the Corporation's non-regulated business; economic conditions; capital resources and liquidity risk; weather and seasonality; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; competitiveness of natural gas; natural gas and fuel supply; regulatory approval of power supply and capacity purchase contracts; defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; loss of licences and permits; loss of service area; changes in tax legislation; information technology infrastructure; an ultimate resolution of the expropriation of the assets of the Exploits Partnership that differs from what is currently expected by management; an unexpected outcome of legal proceedings currently against the Corporation; relations with First Nations; labour relations; and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the year ended December 31, 2010 and for the three and nine months ended September 30, 2011, and as otherwise disclosed in this fourth quarter 2011 media release.*

All forward-looking information in this fourth quarter 2011 media release 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

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. In 2011 the Corporation's electricity distribution systems met a combined peak demand of 5,045 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's 2010 annual audited consolidated financial statements.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation.

Under COS regulation, the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). Generally, the ability of a regulated utility to recover prudently incurred costs of providing service and to earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences within an annual financial reporting period, between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Effective March 1, 2011, the Terasen Gas companies were renamed to operate under a common brand identity with FortisBC in British Columbia, Canada. As a result, Terasen Gas Inc. is now FortisBC Energy Inc. ("FEI"), Terasen Gas (Vancouver Island) Inc. is now FortisBC Energy (Vancouver Island) Inc. ("FEVI") and Terasen Gas (Whistler) Inc. is now FortisBC Energy (Whistler) Inc. ("FEWI"), and collectively are referred to as the FortisBC Energy companies.

On June 20, 2011, the Government of Belize ("GOB") enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet. As at December 31, 2011, the long-term other asset, including foreign exchange impacts, totalled $106 million.

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. The Corporation is pursuing alternative options for obtaining fair compensation from the GOB.

Fortis continues to control and consolidate the financial statements of Belize Electric Company Limited ("BECOL"), the Corporation's indirect wholly owned non-regulated hydroelectric generation subsidiary in Belize. BECOL generates hydroelectricity from three plants located on the Macal River with a combined generating capacity of 51 MW. The entire output of the plants is sold to Belize Electricity under 50-year contracts expiring in 2055 and 2060. Assuming normal hydrological conditions, Belize Electricity purchases BECOL's normalized annual energy production of 240 gigawatt hours ("GWh") at approximately US$0.10 per kilowatt hour, which generally is the lowest-cost energy supply source in the country of Belize. As at December 31, 2011, the book value of the Corporation's investment in BECOL was $154 million. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL.

As at January 31, 2012, Belize Electricity owed BECOL US$7.4 million for overdue energy purchases, representing almost one-third of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

SUMMARY FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's business is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Key financial highlights for the fourth quarters and years ended December 31, 2011 and December 31, 2010 are provided in the following table.

Consolidated Financial Highlights (Unaudited)						
Periods Ended December 31		**Quarter**			**Annual**	
($ millions, except for common share data)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**1,037**	1,034	3	**3,747**	3,657	90
Energy Supply Costs	**490**	507	(17)	**1,697**	1,686	11
Operating Expenses	**237**	228	9	**865**	822	43
Amortization	**108**	103	5	**419**	410	9
Other Income (Expenses), Net	**6**	6	-	**40**	13	27
Finance Charges	**90**	89	1	**370**	362	8
Corporate Taxes	**23**	19	4	**80**	67	13
Net Earnings	**95**	94	1	**356**	323	33
Net Earnings Attributable to:						
Non-Controlling Interests	**2**	2	-	**9**	10	(1)
Preference Equity Shareholders	**7**	7	-	**29**	28	1
Common Equity Shareholders	**86**	85	1	**318**	285	33
Net Earnings	**95**	94	1	**356**	323	33
Basic Earnings per Common Share *($)*	**0.46**	0.49	(0.03)	**1.75**	1.65	0.10
Diluted Earnings per Common Share *($)*	**0.45**	0.47	(0.02)	**1.74**	1.62	0.12
Weighted Average Number of Common Shares Outstanding *(# millions)*	**188.1**	173.9	14.2	**181.6**	172.9	8.7
Cash Flow from Operating Activities	**227**	198	29	**904**	732	172

Factors Contributing to Quarterly Revenue Variance

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the Corporation's Canadian regulated utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure, forecasted higher regulator-approved expenses recoverable from customers, and a higher allowed ROE at Algoma Power
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities
- Growth in the number of customers, mainly at FortisAlberta
- Higher gas sales

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower base component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant Inc. ("Bell Aliant") in 2011

Factors Contributing to Annual Revenue Variance

Favourable

- Same factors as discussed above for the quarter
- Higher electricity sales at the Canadian Regulated Electric Utilities
- The recognition of $3.5 million of accrued revenue at FortisAlberta in 2011, related primarily to the cumulative 2010 and 2011 allowed return and recovery of amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base

Unfavourable

- Same factors as discussed above for the quarter
- Approximately $15 million unfavourable foreign exchange associated with the translation of foreign currency denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year
- Increased performance-based regulation ("PBR")-incentive adjustments to be refunded to customers by FortisBC Electric

Factors Contributing to Quarterly Energy Supply Costs Variance

Favourable

- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower purchased power costs at Maritime Electric and FortisBC Electric

Unfavourable

- Increased fuel prices at Caribbean Utilities
- Higher gas sales

Factors Contributing to Annual Energy Supply Costs Variance

Unfavourable

- Same factors as discussed above for the quarter
- Higher electricity sales at the Canadian Regulated Electric Utilities

Favourable

- Same factors as discussed above for the quarter
- Approximately $8 million associated with favourable foreign currency translation

Factors Contributing to Quarterly and Annual Operating Expenses Variances

Unfavourable

- Higher operating expenses at the FortisBC Energy companies, mainly due to increased wages and benefit costs, and higher asset removal costs, partially offset by lower contractor and consulting expenses and labour savings associated with changes in staffing levels
- The regulator-approved reversal in the third quarter of 2010 at the FortisBC Energy companies of $5 million ($4 million after tax) of project overrun costs previously expensed in 2009 related to the conversion of Whistler customer appliances from propane to natural gas
- Higher operating expenses at Newfoundland Power, mainly due to the regulator-approved change in the accounting treatment for other post-employment benefit ("OPEB") costs, wage and general inflationary cost increases, higher conservation costs related to customer rebate programs and, in addition, increased employee-related expenses for the year.
- Higher operating expenses at FortisBC Electric, largely due to increased vegetation management costs, wage and general inflationary cost increases and higher property taxes

Favourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Operating costs of approximately $2 million incurred during the third quarter of 2010 at Newfoundland Power as a result of Hurricane Igor
- Higher capitalized general overhead expenses, mainly at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power
- Approximately $2 million for the year associated with favourable foreign currency translation

Factors Contributing to Quarterly and Annual Amortization Costs Variances

Unfavourable

- Continued investment in energy infrastructure and income producing properties

Favourable

- Reduced amortization costs in 2011 at the FortisBC Energy companies, mainly due to the retirement late in 2010 of certain general plant assets and the amortization in 2011 of a regulatory deferral account
- Regulator-approved increased amortization costs at Newfoundland Power in 2010, due to approximately $4 million of adjustments related to an amortization study
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $1.5 million for the year associated with favourable foreign currency translation

Factors Contributing to Annual Other Income (Expenses) Variance

Favourable

- The $17 million (US$17.5 million) fee paid to Fortis in July 2011, following the termination of the Merger Agreement with Central Vermont Public Service Corporation ("CVPS")
- Lower corporate business development costs, due to $6 million incurred in the first half of 2010
- A net foreign exchange gain of $1 million associated with the previously hedged investment in Belize Electricity

Factors Contributing to Quarterly and Annual Finance Charges Variances

Unfavourable

- Higher long-term debt levels in support of the utilities' capital expenditure programs

Favourable

- The refinancing of maturing corporate debt at lower rates
- Higher capitalized allowance for funds used during construction ("AFUDC") for the year, mainly at FortisAlberta, partially offset by lower capitalized AFUDC at FortisBC Electric
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011

Factors Contributing to Quarterly and Annual Corporate Taxes Variances

Unfavourable

- Higher earnings before tax in taxable jurisdictions
- Lower deductions for corporate income tax purposes compared to accounting purposes

Favourable

- Lower statutory income tax rates

Factors Contributing to Quarterly Earnings Variance

Favourable

- Higher earnings at the FortisBC Energy companies, driven by rate base growth, lower-than-expected corporate income taxes and finance charges in 2011, and higher gas transportation volumes to the forestry and mining sectors, partially offset by both lower customer additions and capitalized AFUDC

Unfavourable

- Lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011 and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011 and higher electricity sales
- Lower earnings at the Other Canadian Regulated Electric Utilities, mainly associated with decreased electricity sales and higher operating expenses
- Lower earnings at the Caribbean Regulated Electric Utilities, reflecting lower earnings at Fortis Turks and Caicos associated with higher amortization costs and operating expenses, partially offset by reduced energy supply costs in 2011
- Lower earnings at Fortis Properties, mostly due to higher corporate income taxes

Factors Contributing to Annual Earnings Variance

Favourable

- Higher earnings at the FortisBC Energy companies largely for the same reasons as discussed above for the quarter, combined with lower-than-expected amortization costs. Excluding the reversal in 2010 of certain costs previously expensed in 2009, as discussed above in the operating expenses variance, earnings at the FortisBC Energy companies were an additional $4 million higher year over year.
- Higher earnings at FortisAlberta, mainly due to rate base growth, higher capitalized AFUDC, growth in the number of customers and higher energy deliveries, return earned on additional investment in automated meters, as approved by the regulator, and an approximate $1 million gain on the sale of property, partially offset by the impact of a lower allowed ROE for 2011
- Higher earnings at FortisBC Electric, due to rate base growth and lower-than-expected purchased power costs combined with higher electricity sales, partially offset by lower capitalized AFUDC
- Higher earnings at the Other Canadian Regulated Electric Utilities, driven by a higher allowed ROE at Algoma Power
- Lower net corporate expenses due to the $11 million after-tax termination fee paid to Fortis in July 2011, combined with both lower business development costs and finance charges

Unfavourable

- Lower earnings at the Caribbean Regulated Electric Utilities for the same reasons as discussed above for the quarter, combined with the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower earnings at Fortis Properties for the same reason as discussed above for the quarter, combined with lower contribution from the Hospitality Division, partially offset by slightly increased contribution from the Real Estate Division
- Lower earnings at Non-Regulated Generation operations reflecting decreased hydroelectric production in Belize, due to lower rainfall, and overall lower interest income
- Lower earnings at Newfoundland Power for the same reasons as discussed above for the quarter
- Approximately $1 million associated with unfavourable foreign currency translation

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended December 31	Quarter			Annual		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities - Canadian						
FortisBC Energy Companies	**51**	45	6	**139**	130	9
Regulated Electric Utilities - Canadian						
FortisAlberta	***17***	*17*	*-*	***75***	*68*	*7*
FortisBC Electric	***11***	*10*	*1*	***48***	*42*	*6*
Newfoundland Power	***8***	*9*	*(1)*	***34***	*35*	*(1)*
Other Canadian Electric Utilities	***4***	*5*	*(1)*	***22***	*19*	*3*
	40	41	(1)	**179**	164	15
Regulated Electric Utilities - Caribbean	**3**	4	(1)	**20**	23	(3)
Non-Regulated - Fortis Generation	**5**	6	(1)	**18**	20	(2)
Non-Regulated - Fortis Properties	**5**	7	(2)	**23**	26	(3)
Corporate and Other	**(18)**	(18)	-	**(61)**	(78)	17
Net Earnings Attributable to Common Equity Shareholders	**86**	85	1	**318**	285	33

For a discussion of the material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this media release. A discussion of the financial results of the Corporation's reporting segments is as follows.

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Gas Volumes by Major Customer Category (Unaudited)						
Periods Ended December 31	Quarter			Annual		
(TJ)	**2011**	2010	Variance	**2011**	2010	Variance
Core - Residential and Commercial	**42,202**	37,035	5,167	**128,161**	113,635	14,526
Industrial	**1,607**	1,551	56	**5,544**	5,259	285
Total Sales Volumes	**43,809**	38,586	5,223	**133,705**	118,894	14,811
Transportation Volumes	**18,741**	18,405	336	**67,813**	60,363	7,450
Throughput under Fixed Revenue Contracts	**203**	3,407	(3,204)	**1,237**	13,765	(12,528)
Total Gas Volumes	**62,753**	60,398	2,355	**202,755**	193,022	9,733

(1) The FortisBC Energy companies are comprised of FEI, FEVI and FEWI.

Factors Contributing to Quarterly and Annual Gas Volumes Variances

Favourable
- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes reflecting improving economic conditions favourably affecting the forestry and mining sectors

Unfavourable
- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011

Net customer additions were 7,450 for 2011 compared to 9,393 for 2010. Net customer additions decreased year over year due to lower building activity.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the commodity cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

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

Financial Highlights (Unaudited)						
Periods Ended December 31		**Quarter**			**Annual**	
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**477**	479	(2)	**1,568**	1,546	22
Earnings	**51**	45	6	**139**	130	9

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower-than-expected customer additions

Favourable

- An increase in the delivery component of customer rates, mainly due to ongoing investment in energy infrastructure and forecasted higher regulator-approved operating expenses recoverable from customers
- Higher average gas consumption by residential and commercial customers
- Higher gas transportation volumes to the forestry and mining sectors

Factors Contributing to Annual Revenue Variance

Favourable/Unfavourable

- Same factors as discussed above for the quarter

Factors Contributing to Quarterly and Annual Earnings Variances

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Lower-than-expected corporate income taxes and finance charges for the quarter and the year, as well as lower-than-expected amortization costs for the year
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

- The regulator-approved reversal in third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Lower-than-expected customer additions in 2011
- Lower capitalized AFUDC for the quarter, due to a lower asset base under construction during 2011

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	Quarter			Annual		
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Energy Deliveries *(GWh)*	**4,232**	4,255	(23)	**16,367**	15,866	501
Revenue *($ millions)*	**102**	99	3	**409**	385	24
Earnings *($ millions)*	**17**	17	-	**75**	68	7

Factors Contributing to Quarterly Energy Deliveries Variance

Unfavourable

- Lower average consumption by the gas sector, due to decreased activity as a result of low gas market prices
- Lower average consumption by the oilfield sector, and lower average consumption by residential customers due to warmer-than-normal temperatures in the fourth quarter of 2011

Favourable

- Growth in the number of customers, with the total number of customers increasing by approximately 8,000 period over period, driven by favourable economic conditions
- Higher average consumption by farm and irrigation customers, due to differences in rainfall period over period

Factors Contributing to Annual Energy Deliveries Variance

Favourable

- Same factors as discussed above for the quarter
- Higher average consumption by residential customers, mainly due to cooler-than-normal temperatures during the first quarter of 2011

Unfavourable

- Lower average consumption by the gas sector, for the same reason as discussed above for the quarter

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Quarterly and Annual Revenue Variances

Favourable

- The 4.7% increase in base customer electricity distribution rates, effective January 1, 2011. The increase in base rates over 2010 rates was primarily due to ongoing investment in energy infrastructure.
- Growth in the number of customers
- The recognition in 2011 of accrued revenue of $0.5 million for the quarter and $3.5 million for the year, related primarily to the cumulative allowed return and recovery of amortization on the additional $22 million in capital expenditures approved by the regulator to be included in rate base associated with the Automated Metering Project. Approximately $1.5 million of the annual accrual related to 2010. For further information, refer to the "Material Regulatory Decisions and Applications – FortisAlberta" section of this media release.

Unfavourable

- An approximate $2 million rate revenue reduction accrued during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE to 8.75% for 2011 from 9.00% for 2010
- Differences in the amortization of regulatory deferrals to revenue period over period, as approved by the regulator

Factors Contributing to Quarterly Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Higher capitalized AFUDC, due to a higher asset base under construction during 2011

Unfavourable

- The decrease in the allowed ROE for 2011, as discussed above

Factors Contributing to Annual Earnings Variance

Favourable

- Same factors as discussed above for the quarter
- Growth in the number of customers and energy deliveries
- The allowed return and recovery of amortization of approximately $1.5 million recognized in 2011, relating to 2010, on the additional capital expenditures associated with the Automated Metering Project, as discussed above
- An approximate $1 million gain on the sale of property

Unfavourable

- Same factor as discussed above for the quarter
- Lower return earned on the Alberta Electric System Operator ("AESO") charges deferral, due to a decrease in the deferral balance

FORTISBC ELECTRIC (1)

Financial Highlights (Unaudited)	**Quarter**			**Annual**		
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**843**	847	(4)	**3,143**	3,046	97
Revenue *($ millions)*	**81**	73	8	**296**	266	30
Earnings *($ millions)*	**11**	10	1	**48**	42	6

(1) Formerly referred to as FortisBC, and includes the regulated operations of FortisBC Inc. and operating, maintenance and management services related to the Waneta, Brilliant and Arrow Lakes hydroelectric generating plants and the distribution system owned by the City of Kelowna. Excludes the non-regulated generation operations of FortisBC Inc.'s wholly owned partnership, Walden Power Partnership.

Factors Contributing to Quarterly Electricity Sales Variance

Unfavourable

- Lower average consumption, due to warmer-than-normal temperatures experienced during the fourth quarter of 2011 as compared to the same quarter in 2010

Favourable

- Growth in the number of customers

Factors Contributing to Annual Electricity Sales Variance

Favourable

- Same factor as discussed above for the quarter
- Lower average consumption during the first quarter of 2010, due to warmer-than-normal temperatures experienced during that period, resulting in higher electricity sales year over year

Factors Contributing to Quarterly and Annual Revenue Variances

Favourable

- A 6.6% increase in customer electricity rates, effective January 1, 2011, mainly reflecting ongoing investment in energy infrastructure
- A 1.4% and 2.9% increase in customer electricity rates, effective June 1, 2011 and September 1, 2010, respectively, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro

- The 3.2% increase in electricity sales for the year, tempered by the 0.5% decrease in electricity sales for the quarter
- Higher revenue contribution from non-regulated operating, maintenance and management services
- Higher wheeling revenue
- Lower PBR-incentive adjustments to be refunded to customers for the quarter

Unfavourable
- Higher PBR-incentive adjustments to be refunded to customers for the year
- Lower surplus electricity sales for the year

Factors Contributing to Quarterly and Annual
Earnings Variances

Favourable
- Rate base growth, due to continued investment in energy infrastructure
- Lower-than-expected energy supply costs in 2011, primarily due to lower average market-priced purchased power costs
- Higher electricity sales for the year, as discussed above
- Higher earnings contribution from non-regulated operating, maintenance and management services for the year

Unfavourable
- Lower capitalized AFUDC, due to a lower asset base under construction during 2011
- Higher effective corporate income taxes for the year, mainly due to lower deductions for income tax purposes compared to accounting purposes
- Higher-than-expected operating expenses for the fourth quarter of 2011
- Lower electricity sales for the quarter, as discussed above

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)		**Quarter**			**Annual**	
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**1,527**	1,488	39	**5,553**	5,419	134
Revenue *($ millions)*	**156**	152	4	**573**	555	18
Earnings *($ millions)*	**8**	9	(1)	**34**	35	(1)

Factors Contributing to Quarterly and Annual
Electricity Sales Variances

Favourable
- Growth in the number of customers
- Higher average consumption reflecting the higher concentration of electric heating versus oil heating in new home construction combined with strong economic growth

Factors Contributing to Quarterly and Annual
Revenue Variances

Favourable
- The 2.6% and 2.5% increase in electricity sales for the quarter and year, respectively
- An overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly reflecting higher OPEB costs, partially offset by a decrease in the allowed ROE to 8.38% for 2011 from 9.00% for 2010

Unfavourable
- Decreased amortization of regulatory liabilities and deferrals to revenue, as approved by the regulator
- Lower joint-use pole-related revenue, due to new support structure arrangements with Bell Aliant, effective January 1, 2011. For further information, refer to the "Material Regulatory Decisions and Applications – Newfoundland Power" section of this media release.

Factors Contributing to Quarterly and Annual Earnings Variances

Unfavourable

- The decrease in the allowed ROE, as reflected in customer rates
- Lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011
- Higher effective corporate income taxes, primarily due to lower deductions taken for income tax purposes compared to accounting purposes, partially offset by a lower statutory income tax rate
- Higher operating expenses related to wage and general inflationary cost increases and higher conservation costs related to rebate programs offered to customers. Higher operating expenses for the year were also due to increased employee-related expenses, partially offset by lower storm-related costs.

Favourable

- Electricity sales growth
- A reduction in energy supply costs in the fourth quarter of 2011 associated with the Company's hydroelectric generating facilities

OTHER CANADIAN ELECTRIC UTILITIES [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Annual**		
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Electricity Sales *(GWh)*	**568**	578	(10)	**2,366**	2,328	38
Revenue *($ millions)*	**84**	87	(3)	**339**	331	8
Earnings *($ millions)*	**4**	5	(1)	**22**	19	3

(1) Includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and Algoma Power.

Factors Contributing to Quarterly Electricity Sales Variance

Unfavourable

- Lower average consumption by residential customers in Ontario, reflecting more moderate temperatures, which decreased home-heating load
- Lower average consumption by industrial customers on Prince Edward Island ("PEI") due to a reduction in farm-crop storage and warehousing activities

Favourable

- Growth in the number of residential customers
- Higher average consumption by residential customers on PEI, reflecting cooler temperatures which increased home-heating load

Factors Contributing to Annual Electricity Sales Variance

Favourable

- Growth in the number of residential customers
- Higher average consumption by residential customers in Ontario and on PEI, reflecting cooler temperatures, which increased home-heating load

Unfavourable

- Lower average consumption by industrial customers on PEI, for the same reason as discussed above for the quarter

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- The 1.7% decrease in electricity sales
- Lower basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- A rate of return adjustment at Maritime Electric reducing revenue by approximately $2 million in the fourth quarter of 2011, driven by higher-than-expected electricity sales during 2011
- Lower load demand revenue from commercial customers on PEI

Favourable

- An average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010, reflecting an increase in the allowed ROE to 9.85% for 2011 from 8.57% for 2010, and the use of a forward test year for rate setting
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario

Factors Contributing to Annual Revenue Variance

Favourable

- Same factors as discussed above for the quarter
- The 1.6% increase in electricity sales

Unfavourable

- The rate of return adjustment at Maritime Electric during the fourth quarter of 2011, as discussed above
- Lower basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- Lower electricity sales at FortisOntario
- The rate of return adjustment at Maritime Electric during the fourth quarter of 2011, as discussed above
- Higher operating expenses associated with vegetation management activities, retirement and other employee-related costs

Favourable

- A higher allowed ROE at Algoma Power and the use of a forward test year for rate setting, as reflected in customer rates for 2011
- Rate base growth, due to continued investment in energy infrastructure
- Lower effective corporate income taxes, primarily due to higher deductions taken for income tax purposes compared to accounting purposes

Factors Contributing to Annual Earnings Variance

Favourable

- Same factors as discussed above for the quarter
- Electricity sales growth

Unfavourable

- The rate of return adjustment at Maritime Electric during the fourth quarter of 2011, as discussed above

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Annual**		
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Average US:CDN Exchange Rate [(2)]	**1.02**	1.01	0.01	**0.99**	1.03	(0.04)
Electricity Sales *(GWh)*	**174**	270	(96)	**918**	1,150	(232)
Revenue *($ millions)*	**70**	84	(14)	**305**	333	(28)
Earnings *($ millions)*	**3**	4	(1)	**20**	23	(3)

(1) Includes Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 60% controlling interest; wholly owned Fortis Turks and Caicos; and the financial results of the Corporation's approximate 70% controlling interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the GOB expropriated the Corporation's investment in Belize Electricity. As a result, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information, refer to the "Corporate Overview" section of this media release.

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

Factors Contributing to Quarterly and Annual Electricity Sales Variances

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. For further information, refer to the "Corporate Overview" section of this media release.
- Reduced energy consumption due to challenging economic conditions in the region, the high cost of fuel, and the early and extended closure of certain hotel and other commercial customers in the Turks and Caicos Islands resulting from a hurricane in August 2011
- The number of work permit holders in the region has declined significantly, causing some rental properties with active electricity connections to be vacant.

Favourable

- Growth in the number of customers in Grand Cayman and the Turks and Caicos Islands
- Excluding Belize Electricity, electricity sales growth was 3.7% for the quarter. There was no growth in electricity sales year over year
- Electricity sales for the fourth quarter of 2011 were impacted by warmer weather conditions in the region that favourably impacted customer air conditioning load

Factors Contributing to Quarterly and Annual Revenue Variances

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $13 million of unfavourable foreign exchange for the year associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the price of fuel
- Higher electricity sales for the quarter, excluding Belize Electricity
- Approximately $1 million of favourable foreign exchange for the quarter associated with the translation of foreign currency-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar quarter over quarter

Factors Contributing to Quarterly and Annual Earnings Variances

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. There was no earnings contribution from Belize Electricity during 2011, while the Company contributed $1.5 million in earnings in 2010, with a loss of $0.5 million incurred in the fourth quarter of 2010.
- Higher amortization, excluding the impact of foreign exchange, largely at Fortis Turks and Caicos, due to investment in utility capital assets, including the commencement of amortization in 2011 of a new operations centre and generating unit
- Higher operating expenses, excluding the impact of foreign exchange, at Fortis Turks and Caicos, largely due to consulting fees associated with ongoing regulatory matters and inflationary cost increases

Favourable

- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility
- Higher electricity sales for the quarter, excluding Belize Electricity

NON-REGULATED - FORTIS GENERATION [1]

Financial Highlights (Unaudited)	**Quarter**			**Annual**		
Periods Ended December 31	**2011**	2010	Variance	**2011**	2010	Variance
Energy Sales *(GWh)*	**112**	137	(25)	**389**	427	(38)
Revenue *($ millions)*	**9**	9	-	**34**	36	(2)
Earnings *($ millions)*	**5**	6	(1)	**18**	20	(2)

[1] Includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State, with a combined generating capacity of 139 MW, mainly hydroelectric. Results reflect contribution from the Vaca hydroelectric generating facility in Belize from late March 2010 when the facility was commissioned.

Factors Contributing to Quarterly and Annual Energy Sales Variances

Unfavourable

- Decreased production in Belize for the year, due to lower rainfall in the first three quarters of 2011 associated with a longer dry season
- Decreased production in Upper New York State, due to a generating plant being out of service since May 2011

Favourable

- Increased production in Belize for the quarter, due to higher rainfall

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- Lower average energy sales rate per megawatt hour ("MWh") in Upper New York State. The average rate per MWh for the fourth quarter of 2011 was US$35.79 compared to US$43.64 for the same quarter in 2010.

Favourable

- Increased production in Belize

Factors Contributing to Annual Revenue Variance

Unfavourable

- Decreased production in Belize

Favourable

- Higher annual average energy sales rate per MWh in Ontario. The annual average rate per MWh was $72.96 in 2011 compared to $53.17 in 2010. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract with price indexing. Previously, energy was sold at market rates.

Factors Contributing to Quarterly Earnings Variances

Unfavourable

- Lower average energy sales rate per MWh in Upper New York State
- Lower interest income at Ontario operations associated with lower inter-company lending to regulated operations in Ontario
- Higher business development costs at Ontario operations

Favourable

- Increased production in Belize

Factors Contributing to Annual Earnings Variances

Unfavourable

- Decreased production in Belize
- Lower interest income at Ontario operations, for the same reason as discussed above for the quarter

Favourable

- Higher annual average energy sales rate per MWh in Ontario
- Lower finance charges and higher interest income associated with operations in Belize

In May 2011 the generator at Moose River's hydroelectric generating facility in Upper New York State sustained damage. Equipment and business interruption insurance claims are ongoing. Revenue for 2011 reflects the accrual of the 2011 earnings impact of the shut down of the facility that is recoverable from the insurance claim. The generator is under repair and the facility is expected to be operational in late March 2012.

NON-REGULATED - FORTIS PROPERTIES *(1)*

Financial Highlights (Unaudited) Periods Ended December 31 *($ millions)*	**Quarter** **2011**	 2010	 Variance	**Annual** **2011**	 2010	 Variance
Hospitality Revenue	**41**	40	1	**164**	160	4
Real Estate Revenue	**17**	17	-	**67**	66	1
Total Revenue	**58**	57	1	**231**	226	5
Earnings	**5**	7	(2)	**23**	26	(3)

(1) Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms in eight Canadian provinces, and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Factors Contributing to Quarterly Revenue Variance

Favourable

- Revenue contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011
- A 2.3% increase in revenue per available room ("RevPar"), excluding the impact of the Hilton Suites Winnipeg Airport hotel, at the Hospitality Division to $72.39 for the fourth quarter of 2011 from $70.76 for the same quarter of 2010. RevPar increased due to an overall 2.6% increase in the average daily room rate, partially offset by an overall 0.3% decrease in hotel occupancy. The average daily room rate increased in all regions. Occupancy increases were achieved in Atlantic Canada and central Canada but were more than offset by occupancy decreases experienced in western Canada. Including the Hilton Suites Winnipeg Airport hotel, RevPar was $73.66 for the fourth quarter of 2011.
- Rental rate increases at the Real Estate Division

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division to 93.2% as at December 31, 2011 from 94.5% as at December 31, 2010

Factors Contributing to Annual Revenue Variance

Favourable

- Revenue contribution from the Hilton Suites Winnipeg Airport hotel, as discussed above for the quarter
- A 2.1% increase in RevPar, excluding the impact of the Hilton Suites Winnipeg Airport hotel, at the Hospitality Division to $78.48 for 2011 from $76.83 for 2010. RevPar increased due to an overall 2.7% increase in the average daily room rate, partially offset by an overall 0.6% decrease in hotel occupancy. The average daily room rate increased in all regions. Occupancy increases were achieved in Atlantic Canada and central Canada but were more than offset by occupancy decreases experienced in western Canada. Including the Hilton Suites Winnipeg Airport hotel, RevPar was $78.76 for 2011.
- Rental rate increases at the Real Estate Division

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division, as discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- Higher corporate income taxes. Lower statutory income tax rates and their effect of reducing future income tax liability balances in the fourth quarter of 2010 favourably impacted corporate income taxes in 2010.

Favourable

- Higher contribution from the Hospitality Division, driven by the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011

Factors Contributing to Annual Earnings Variance

Unfavourable

- Same factor as discussed above for the quarter
- Lower contribution from the Hospitality Division, reflecting lower performance at operations in western Canada, due to decreased occupancy rates, and at operations in central Canada, partially offset by improved performance at operations in Newfoundland, Atlantic Canada, reflecting strong local economic conditions
- Higher corporate administrative expenses

Favourable

- Higher contribution from the Real Estate Division, mainly due to the $0.5 million gain on the sale of the Viking Mall in 2011

CORPORATE AND OTHER [1]

Financial Highlights (Unaudited)						
Periods Ended December 31		**Quarter**			**Annual**	
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Revenue	**7**	7	-	**29**	29	-
Operating Expenses	**3**	4	(1)	**10**	10	-
Amortization	**2**	2	-	**7**	7	-
Other Income (Expenses), Net	**1**	-	1	**21**	(5)	26
Finance Charges [2]	**17**	16	1	**71**	73	(2)
Corporate Tax Recovery	**(3)**	(4)	1	**(6)**	(16)	10
	(11)	(11)	-	**(32)**	(50)	18
Preference Share Dividends	**7**	7	-	**29**	28	1
Net Corporate and Other Expenses	**(18)**	(18)	-	**(61)**	(78)	17

[1] Includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") (formerly Terasen Inc.) corporate-related activities and the financial results of FHI's 30% ownership interest in CustomerWorks Limited Partnership and of FHI's non-regulated wholly owned subsidiary FortisBC Alternative Energy Services Inc. (formerly Terasen Energy Services Inc.)

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

Factors Contributing to Annual Net Corporate and Other Expenses Variance

Favourable

- Higher other income, net of expenses, due to: (i) a $17 million (US$17.5 million) ($11 million after tax) fee paid to Fortis in July 2011, following the termination of a Merger Agreement between Fortis and CVPS; and (ii) a $4.5 million foreign exchange gain associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity. The foreign exchange gain was partially offset by a $3.5 million ($3 million after-tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated debt. The favourable net impact to 2011 earnings of the above foreign exchange impacts was approximately $1.5 million. Business development costs of approximately $6 million ($4 million after tax) incurred in the first half of 2010 also had a favourable impact on other income, net of expenses, year over year.

- Lower finance charges due to the refinancing of maturing corporate debt at lower rates, the repayment of credit facility borrowings during the third quarter of 2011 with a portion of the proceeds from the common share offering in June and July 2011, and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense.

Unfavourable

- Finance charges were reduced in the fourth quarter of 2010, related to the finalization of capitalized interest on a construction project.
- Higher preference share dividends, due to the issuance of First Preference Shares, Series H in January 2010

On July 11, 2011, the Board of Directors of CVPS determined that the acquisition proposal from Gaz Métro Limited Partnership was a “Superior Proposal”, as that term was defined in the Merger Agreement between Fortis and CVPS announced on May 30, 2011, and CVPS elected to terminate the Merger Agreement in accordance with its terms. Prior to such termination taking effect, the Merger Agreement provided Fortis the right to require CVPS to negotiate with Fortis for at least five business days with respect to any changes to the terms of the Merger Agreement proposed by Fortis. Fortis agreed to waive such right in exchange for the prompt payment by CVPS to Fortis of the US$17.5 million termination fee plus US$2.0 million for the reimbursement of expenses as set forth in the Merger Agreement, thereby resulting in the termination of the Merger Agreement. Fortis received the $18.8 million (US$19.5 million) payment on July 12, 2011.

REGULATORY HIGHLIGHTS

The nature of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities for 2011 are summarized as follows:

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review with the British Columbia Utilities Commission ("BCUC") natural gas and propane commodity prices every three months and midstream costs annually, in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane and contracting for midstream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and propane and midstream costs are flowed through to customers without markup. The bundled rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balance in the Commodity Cost Reconciliation Account is recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and midstream costs. Effective January 1, 2011, FEWI's interim residential customer rates decreased by approximately 5% and FEVI's rates remained unchanged. • Natural gas commodity rates remained unchanged for April 1, 2011 and July 1, 2011, following the BCUC's quarterly reviews of commodity costs. • Effective October 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 5% to reflect changes in commodity costs, following the BCUC's quarterly review of such costs. FEWI and FEVI's rates remained unchanged. • Effective January 1, 2012, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas increased by approximately 3% and rates for FEWI's residential customers increased by approximately 6%, reflecting changes in delivery and midstream costs with the rates being set on an interim basis, pending a final decision on the gas utilities' 2012-2013 Revenue Requirements Applications. Interim approval has also been received from the BCUC to hold FEVI customer rates at 2011 levels, effective January 1, 2012. Natural gas commodity rates remained unchanged, effective January 1, 2012. • In December 2010 FEI filed an application with the BCUC to provide fueling services through FEI-owned and operated compressed natural gas and liquefied natural gas ("LNG") fuelling stations. In July 2011 FEI received a decision from the BCUC that approved the fuelling station infrastructure along with a long-term contract with one counterparty for the supply of compressed natural gas. The BCUC denied the Company's application for a general tariff for the provision of compressed natural gas and LNG for vehicles, unless certain contractual conditions are met. FEI refiled an amended application for a general tariff and is awaiting a final decision from the BCUC. • In May 2011, in response to a complaint, the BCUC initiated a public process to develop guidelines under which FEI should be able to provide "alternative energy services" as regulated utility services. The "alternative energy services" offered by FEI include providing refueling services for natural gas vehicles ("NGVs"), owning and operating district energy systems and various forms of geo-exchange systems, and owning facilities that upgrade raw biogas into biomethane for the purpose of selling it to customers. • In July 2011 the BCUC approved the application jointly filed by the FortisBC Energy companies and FortisBC Electric requesting the utilities be permitted to adopt US generally accepted accounting principles ("US GAAP") effective January 1, 2012 for regulatory reporting purposes. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to 15% in the equity component of the capital structure of the new LNG storage facility on Vancouver Island. In late 2011 each band exercised its option and each invested approximately $6 million in equity in the LNG facility on January 1, 2012. • In August 2011 FEI and FEVI received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for NGVs. The utilities had made these funds available to assist large customers in purchasing NGVs in lieu of vehicles fueled by diesel. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC has requested that the companies provide further submissions to determine the prudency of the EEC incentives at a future time.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI / FEVI / FEWI (cont'd)	• In January 2011 FEI and FEVI filed a report of a review of their Price Risk Management Plan ("PRMP") objectives with the BCUC related to their gas commodity hedging plan and FEI also submitted a revised 2011-2014 PRMP. In July 2011 the BCUC issued its decision on the report and determined that commodity hedging in the current environment was not a cost-effective means of meeting the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011-2014 PRMP with the exception of certain elements to address regional price discrepancies. As a result, FEVI and FEI have suspended commodity-hedging activities with the exception of limited swaps as permitted by the BCUC. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged. • In September 2011 the FortisBC Energy companies filed an update to their 2012-2013 Revenue Requirements Applications. FEI has requested an increase in rates of 3.0%, effective January 1, 2012, and 3.1%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEI's application assumes forecast average rate base of approximately $2,760 million for 2012 and $2,820 million for 2013. FEVI has requested that rates remain unchanged for the two-year period commencing January 1, 2012. FEVI's application assumes forecast average rate base of $788 million for 2012 and $816 million for 2013. FEWI has requested an increase in rates of approximately 6.5%, effective January 1, 2012, and approximately 4.3%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEWI's application assumes forecast average rate base of $42 million for 2012 and $41 million for 2013. The requested rates reflect allowed ROEs and capital structure unchanged from 2011. The requested rate increases are driven by ongoing investment in energy infrastructure focused on system integrity and reliability, and forecast increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas system, and increasing compliance with codes and regulations. A decision on the rate applications is expected in the first half of 2012. • In October 2011 FEI filed an application for approval of expenditures of approximately $5 million on facilities required to provide thermal energy services to 19 buildings in the Delta School District located in the Greater Vancouver area. When complete, FEI will own, operate and maintain the new thermal plants and charge the Delta School District a single rate for thermal energy consumed. In November 2011 FEI refiled the application with amended third-party contracts related to the thermal energy services to allow more time for a public review process. A decision on the application is expected by the end of the first quarter of 2012. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity, and for the implementation of common rates and services for the utilities' customers across British Columbia, effective January 1, 2013. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia. In late 2011 the utilities temporarily suspended their application while they are providing additional information to the BCUC, as requested. • In November 2011 the BCUC gave preliminary notification to public utilities subject to its regulation, including the FortisBC Energy companies and FortisBC Electric, of its intention to initiate a Generic Cost of Capital proceeding early in 2012. During the proceeding, the BCUC intends to review the following items: (i) setting the appropriate cost of capital for a benchmark low-risk utility; (ii) establishing an ROE automatic adjustment mechanism; and (iii) establishing a deemed capital structure and deemed cost of capital methodology, particularly for those utilities in British Columbia without third-party debt. FortisBC will be involved in this regulatory process in 2012. The cost of capital review may result in a change in the utilities' capital structures and allowed ROEs.
FortisBC Electric	• In December 2010 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to FortisBC Electric's 2011 Revenue Requirements Application and Capital Expenditure Plan. The result was a general customer electricity rate increase of 6.6%, effective January 1, 2011. The rate increase was primarily the result of the Company's ongoing investment in energy infrastructure, including increased amortization and financing costs. • Effective June 1, 2011, the BCUC approved an increase of 1.4% in FortisBC Electric customer electricity rates arising from an increase in purchased power costs due to an increase in BC Hydro rates.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisBC Electric (cont'd)	• In June 2011 FortisBC Electric filed its 2012-2013 Revenue Requirements Application, which included its 2012-2013 Capital Expenditure Plan, and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. The requested rates reflect an allowed ROE and capital structure unchanged from 2011. In addition to a continuation of deferral accounts and flow-through treatments that existed under the PBR agreement, which expired at the end of 2011, the 2012–2013 Revenue Requirements Application proposes deferral accounts and flow-through treatment for variances from the forecast used to set customer rates for electricity revenue, purchased power costs and certain other costs. • In November 2011 FortisBC Electric filed an updated 2012-2013 Revenue Requirements Application to include updated financial estimates and forecasts, resulting in a revised requested increase in rates of 1.5%, effective January 1, 2012, and 6.5%, effective January 1, 2013. The revised application assumes forecast average rate base of approximately $1,146 million for 2012 and $1,215 million for 2013. An oral hearing process is expected to occur in March 2012 with a decision expected during 2012. • An interim, refundable customer rate increase of 1.5%, effective January 1, 2012, was approved by the BCUC, pending a final decision on the Company's 2012-2013 Revenue Requirements Application.
FortisAlberta	• In December 2010 the Alberta Utilities Commission ("AUC") issued its decision on FortisAlberta's August 2010 Compliance Filing, which incorporated the AUC's decision, received in July 2010, on the Company's 2010 and 2011 Distribution Tariff Application ("DTA"). The December 2010 decision approved the Company's distribution revenue requirements of $368 million for 2011. Final distribution electricity rates and rate riders were also approved, effective January 1, 2011. • In June 2011 the AUC issued its decision regarding the prudency of additional capital expenditures above $104 million related to the Company's Automated Metering Project. In its decision, the AUC concluded that the full amount of the forecasted total project cost of $126 million could be included in rate base and collected in customer rates. The impact of the decision was the recognition of $3.5 million in accrued revenue in 2011 and an associated regulatory asset as at December 31, 2011. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC requesting that, effective January 1, 2012, CAREA be entitled to service any new customers wishing to obtain electricity for use on property overlapping CAREA's service area and that FortisAlberta be restricted to providing service in the CAREA service area only to those customers in that service area who are not being provided service by CAREA. FortisAlberta has intervened in the proceedings to oppose CAREA's request. A decision on this matter is expected in 2012. • In 2010 the AUC initiated a process to reform utility rate regulation for distribution utilities in Alberta. The AUC intends to introduce PBR-based distribution service rates beginning in 2013 for a five-year term, with 2012 to be used as the base year. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter is expected to commence in April 2012 with a decision expected in 2012. • In March 2011 FortisAlberta filed its 2012 and 2013 DTA. The AUC allowed FortisAlberta, at the Company's request, to settle the DTA through negotiation, but stipulated that the negotiation apply only to 2012 rates in light of the AUC's target of commencing PBR-based rate setting in 2013. In November 2011 FortisAlberta filed an NSA pertaining to 2012 customer distribution rates. The NSA proposes an average rate increase of approximately 5% effective January 1, 2012. FortisAlberta's average rate base is currently forecast at $2.0 billion for 2012 and $2.3 billion for 2013. The requested rate increase is driven primarily by ongoing investment in energy infrastructure, including increased amortization and financing costs. In December 2011 the AUC approved an interim average rate increase of approximately 5%, effective January 1, 2012, reflecting the parameters of the NSA. The Company has also requested that volume variances be included in FortisAlberta's AESO charges deferral account for 2012, consistent with the deferral structure that was in place in 2011. A decision on the NSA is expected in the first half of 2012.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In December 2011 the AUC issued its decision on its 2011 Generic Cost of Capital Proceeding, establishing the allowed ROE at 8.75% for 2011 and 2012, and, on an interim basis, at 8.75% for 2013. The equity component of FortisAlberta's capital structure remains at 41% and will continue at that level until any future order of the AUC that may change it. The AUC concluded that it would not return to a formula-based ROE automatic adjustment mechanism at this time and that it would initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula-based approach in future periods. FortisAlberta and other distribution utilities in Alberta filed motions for leave to appeal with the Alberta Court of Appeal with respect to the cost of capital decision challenging certain pronouncements made by the AUC as being incorrectly made regarding cost responsibility for stranded assets. In February 2012 FortisAlberta and other utilities filed requests with the AUC for the AUC to review and vary its pronouncements.
Newfoundland Power	• In December 2010 the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset balance of approximately \$53 million, associated with adoption of accrual accounting, over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the PUB for rate-setting purposes. • In December 2010 Newfoundland Power received approval from the PUB for an overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly resulting from the PUB's approval for the Company to change its accounting for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011. • On January 1, 2011, new support structure arrangements with Bell Aliant went into effect, including Bell Aliant repurchasing 40% of all joint-use poles and related infrastructure from Newfoundland Power, representing approximately 5% of Newfoundland Power's rate base. In 2001 Newfoundland Power purchased Bell Aliant's (formerly Aliant Telecom Inc.) joint-use poles and related infrastructure under a 10-year Joint-Use Facilities Partnership Agreement ("JUFPA"), which expired on December 31, 2010. Bell Aliant had rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term of the JUFPA. Bell Aliant exercised the option to buy back these poles from Newfoundland Power in 2010. The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of the joint-use poles. The PUB issued an order approving the sale of the joint-use poles in September 2011. Effective January 1, 2011, Newfoundland Power no longer received pole rental revenue from Bell Aliant. Newfoundland Power was responsible for the construction and maintenance of Bell Aliant's support structure requirements in 2011. The new support structure arrangements had no material impact on Newfoundland Power's ability to earn a reasonable return on its rate base in 2011. Proceeds of approximately \$46 million from the sale of 40% of the joint-use poles were received by Newfoundland Power from Bell Aliant in October 2011. The sale proceeds were used to pay down credit facility borrowings and pay a special dividend of approximately \$30 million to Fortis in order to maintain Newfoundland Power's capital structure at 45% common equity. In January 2012 the transaction with Bell Aliant closed and a purchase price adjustment of approximately \$1 million was paid to Bell Aliant by Newfoundland Power. The purchase price adjustment was based on the results of a pole survey completed in the fourth quarter of 2011. • In October 2011 the PUB approved Newfoundland Power's application requesting the deferral of expected increased costs of \$2.4 million in 2012, due to expiring regulatory amortizations. • In December 2011 the PUB approved Newfoundland Power's application requesting the adoption of US GAAP, effective January 1, 2012, for regulatory reporting purposes. • In December 2011 the PUB approved, as filed, Newfoundland Power's 2012 Capital Expenditure Plan totalling approximately \$77 million. • In November 2011 Newfoundland Power's allowed ROE for 2012 was calculated at 7.85% under the ROE automatic adjustment formula, a decrease from 8.38% for 2011. In December 2011 the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 and to review cost of capital for 2012. As a result, current customer rates and the allowed ROE of 8.38% will continue in effect for 2012 on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012. • Newfoundland Power's average rate base for 2012 is forecasted at \$879 million. • The Company is currently assessing the requirement for it to file a general rate application with the PUB to recover increased costs in 2013.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Maritime Electric	• In November 2010 Maritime Electric signed the PEI Energy Accord (the "Accord") with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by the Island Regulatory and Appeals Commission ("IRAC"), incremental replacement energy costs incurred during the refurbishment of Point Lepreau up to the end of February 2011 were deferred by Maritime Electric and totalled approximately $47 million. The deferred costs are included in rate base. • The nature and timing of the recovery of the deferred costs related to Point Lepreau is subject to further review by the PEI Energy Commission (the "Commission"), which was recently established by the Government of PEI. Having authority under the *Public Inquiries Act,* the co-chaired five-member Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, amongst other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year power purchase agreement between Maritime Electric and NB Power, customer electricity rates decreased overall by approximately 14%, effective March 1, 2011, reflecting a decrease in the Energy Cost Adjustment Mechanism and base component of rates. A two-year customer rate freeze commenced after the March 1, 2011 rate adjustment. The allowed ROE for 2011 and 2012 is 9.75%, as set under the terms of the Accord. • Maritime Electric intends to file an application with IRAC in fall 2012 for 2013 customer rates and allowed ROE.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the Ontario Energy Board ("OEB"). In March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflected an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an average customer's electricity bill, including rate riders and other charges, was an overall increase of 3.8%. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the Rural and Remote Rate Protection ("RRRP") Program. Algoma Power consulted with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. The balance of Algoma Power's revenue requirement is recovered from the RRRP Program. In September 2011 Algoma Power filed its first Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The Third-Generation IRM maintains the allowed ROE at 9.85%. Algoma Power has proposed that both electricity rates and funding under the RRRP Program be indexed through a price-cap formula. In December 2011 the OEB approved current customer rates as interim rates for 2012 for Algoma Power, pending a final decision on Algoma Power's rate application. The outcome of Algoma Power's rate application will likely determine whether the Company will remain under incentive regulation for the full IRM cycle. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro Inc. ("Port Colborne Hydro") with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase is subject to OEB approval.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In November 2011 the OEB published the applicable inflationary factor of 1.7% for Third-Generation IRM rate applications having a January 1, 2012 effective date. • In November 2011 FortisOntario filed a Third-Generation IRM application for rates effective May 1, 2012 for its operations in Port Colborne and a similar, but harmonized, rate application for its operations in Fort Erie and Gananoque, effective May 1, 2012. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. • FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario. • In November 2011 the OEB published the allowed ROE of 9.42% for 2012, as calculated under the ROE automatic adjustment mechanism. This allowed ROE is not applicable to regulated electric utilities in Ontario until they are scheduled to file full COS rate applications. As a result, this allowed ROE will not be applicable to FortisOntario's utilities in 2012.
Caribbean Utilities	• In March 2011 Caribbean Utilities confirmed to the Electricity Regulatory Authority ("ERA") that the Rate-Cap Adjustment Mechanism, as provided in the Company's transmission and distribution licence, yielded no customer rate adjustment effective June 1, 2011. • In March 2011 the ERA approved a Fuel Price Volatility Management Program for the utility. The objective of the program is to reduce the impact of volatility in the fuel cost charge paid by Caribbean Utilities' customers for the fuel that it must purchase in order to provide electric service. The program utilizes call options creating a ceiling price for fuel costs at predetermined contract premiums. The program currently covers 40% of expected fuel consumption. • In July 2011 the ERA approved Caribbean Utilities' request to use US GAAP for regulatory reporting purposes, effective January 1, 2012. • In March 2011 the ERA approved $134 million of proposed non-generation installation expenditures in Caribbean Utilities' 2011-2015 Capital Investment Plan ("CIP"). The remaining $85 million of the CIP related to new generation installation, which would be subject to a competitive solicitation process. • In November 2011 CUC issued a Certificate of Need to the ERA for 18 MW of new generating capacity to be installed in 2014 and for an additional 18 MW of generating capacity to be installed in either 2015 or 2016, contingent on growth over the next two years. The primary driver for the new generating capacity in 2014 is the upcoming scheduled retirements of several of Caribbean Utilities' generating units, which are reaching the end of their useful lives. As a result of the Company expressing its need for replacement capacity, the ERA will be conducting a competitive solicitation process in 2012 in accordance with Caribbean Utilities' licenses, which will allow all interested and qualified parties, including Caribbean Utilities, to submit bids to fill the Company's firm capacity requirement. • In December 2011 Caribbean Utilities filed its 2012-2016 CIP totaling approximately US$192 million, including generation capital expenditures. The 2012-2016 CIP has been prepared in line with the Certificate of Need that was filed with the ERA in November 2011, as discussed above. A decision on the CIP is expected during the first quarter of 2012. • In December 2011 Caribbean Utilities conducted and completed a competitive bidding process to fill 13 MW of nonfirm renewable energy capacity. There are currently no viable renewable energy sources on Grand Cayman that meet Caribbean Utilities' reliability requirements for firm capacity; however, Caribbean Utilities expects that there are third parties that can build and maintain renewable energy plants on Grand Cayman and sell energy to Caribbean Utilities' at a competitive price to diesel. Any resulting power purchase agreements, however, are subject to ERA review and approval.
Fortis Turks and Caicos	• In March 2011 Fortis Turks and Caicos submitted its 2010 annual regulatory filing outlining the Company's performance in 2010. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$142 million for 2010 and cumulative shortfall in achieving allowable profits of US$49 million as at December 31, 2010. • In August 2011 Fortis Turks and Caicos filed with the Interim Government of the Turks and Caicos Islands ("Interim Government") an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. Fortis Turks and Caicos is currently in negotiations with the Interim Government, which had approved in October 2011 an increase in large hotel rates, which comprised approximately half of the Company's overall requested increase in customer rates. The Company made a counter proposal to the Interim Government in January 2012 and expects a final determination on the Electricity Rate Variance Application by the end of the first quarter of 2012.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Fortis Turks and Caicos (cont'd)	• An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the Interim Government. The purpose of the review was to: (i) assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency; (ii) assess the current and proposed electricity costs and tariffs in the Turks and Caicos Islands in relation to comparable regional and international utilities; (iii) make recommendations for a revised regulatory framework and *Electricity Ordinance*; and (iv) make recommendations for the implementation and operation of the revised regulatory framework. Fortis Turks and Caicos provided a comprehensive response to the Interim Government in January 2012 stating that the Company supports limited mutually agreed upon reforms, but that its current licenses must be respected and can only be changed by mutual consent. Specifically, Fortis Turks and Caicos would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. • Earlier in 2011 the Interim Government publicly stated its intention to implement a carbon tax, effective September 2011, that would be applicable to Fortis Turks and Caicos but which may not be permitted to be passed on to Fortis Turks and Caicos' customers. To date, no carbon tax has been implemented. Under the terms of an agreement with the Government of the Turks and Caicos Islands when Fortis Turks and Caicos was granted its licence, the Company is exempt from any taxes other than customs duties where applicable by law.

LIQUIDITY AND CAPITAL RESOURCES

The table below outlines the Corporation's consolidated sources and uses of cash for the fourth quarter and year ended December 31, 2011, as compared to the same periods in 2010, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)

Periods Ended December 31	Quarter			Year		
($ millions)	**2011**	2010	Variance	**2011**	2010	Variance
Cash, Beginning of Period	**108**	64	44	**109**	85	24
Cash Provided by (Used in):						
Operating Activities	**227**	198	29	**904**	732	172
Investing Activities	**(369)**	(333)	(36)	**(1,125)**	(991)	(134)
Financing Activities	**124**	180	(56)	**201**	283	(82)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(1)**	-	(1)	**-**	-	-
Cash, End of Period	**89**	109	(20)	**89**	109	(20)

Operating Activities: Cash flow from operating activities, after working capital adjustments, was $29 million higher quarter over quarter and $172 million higher year over year. The increases were mainly due to favourable changes in working capital and higher earnings. Quarter over quarter, favourable working capital changes associated with accounts receivable and inventories were partially offset by unfavourable changes in accounts payable. The favourable working capital changes year over year, associated primarily with accounts payable, accounts receivable and inventories, were driven by the FortisBC Energy companies and FortisAlberta.

Investing Activities: Cash used in investing activities was $36 million higher quarter over quarter. The increase was due to a $49 million deferred payment being made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002. The deferred payment was originally classified in long-term other liabilities. Cash used in investing activities also increased as a result of the acquisition of the Hilton Suites Winnipeg Airport hotel in 2011. The increases were partially offset by higher proceeds from the sale of utility capital assets associated with the sale of joint-use poles at Newfoundland Power in October 2011.

Cash used in investing activities was $134 million higher year over year. The increase was due to the same reasons as discussed above for the quarter, as well as higher capital spending related to the non-regulated Waneta hydroelectric generation expansion project ("Waneta Expansion Project") and higher capital spending at FortisAlberta, partially offset by lower capital spending at FortisBC Electric.

Financing Activities: Cash provided by financing activities was $56 million lower quarter over quarter, due to: (i) lower proceeds from long-term debt; (ii) higher repayments of short-term borrowings; and (iii) lower advances from non-controlling interests in the Waneta Expansion Limited Partnership ("Waneta Partnership"), partially offset by lower repayments of both long-term debt and committed credit facility borrowings classified as long-term.

Cash provided by financing activities was $82 million lower year over year, due to: (i) lower proceeds from the issuance of preference shares; (ii) lower proceeds from long-term debt; (iii) higher repayments of short-term borrowings; (iv) higher repayments of committed credit facility borrowings classified as long-term; and (v) higher common share dividends, partially offset by: (i) higher proceeds from the issuance of common shares; (ii) lower repayments of long-term debt; and (iii) higher advances from non-controlling interests in the Waneta Partnership.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

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

Capital Structure (Unaudited)	**As at**			
	December 31, 2011		December 31, 2010	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**5,855**	**55.0**	5,914	58.4
Preference shares [(2)]	**912**	**8.6**	912	9.0
Common shareholders' equity	**3,877**	**36.4**	3,305	32.6
Total [(3)]	**10,644**	**100.0**	10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Includes preference shares classified as both long-term liabilities and equity
(3) Excludes amounts related to non-controlling interests

The improvement in the capital structure was driven by the public offering of approximately $341 million of common shares in June and July 2011, combined with common shares issued under the Corporation's dividend reinvestment and stock option plans, and the reclassification of net unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity to long-term other assets. Also contributing to the improvement were net earnings attributable to common equity shareholders, net of dividends, combined with an overall decrease in total debt. A portion of the proceeds from the public common equity offering were used to repay credit facility borrowings in 2011.

***Credit Ratings*:** The Corporation's credit ratings are as follows:

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

During the third quarter of 2011, DBRS confirmed the Corporation's existing debt credit rating at A(low). S&P is expected to complete its annual review of the Corporation's credit rating in the first quarter of 2012. The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

CAPITAL PROGRAM

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred.

A breakdown of the approximate $1.2 billion in gross capital expenditures by segment for 2011 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year Ended December 31, 2011
($ millions)

FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean** [(3)]	**Non-Regulated - Utility** [(4)]	**Fortis Properties**	**Total**
253	416	102	81	47	**899**	**71**	**174**	**30**	**1,174**

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected in the consolidated statement of cash flows. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2011. Excludes capitalized amortization and non-cash equity component of AFUDC.
(2) Includes payments made to AESO for investment in transmission-related capital projects
(3) Includes capital expenditures at Belize Electricity up to June 20, 2011
(4) Includes non-regulated generation, mainly related to the Waneta Expansion Project, and corporate capital expenditures

Gross consolidated capital expenditures of $1,174 million for 2011 were $38 million lower than $1,212 million forecasted for 2011, as disclosed in the MD&A for the year ended December 31, 2010. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts. Lower-than-forecasted capital spending was mainly due to: (i) a shift in the timing of certain capital expenditures from 2011 to 2012 and various individually small capital projects determined not to be required at the FortisBC Energy companies; (ii) the discontinuance of the consolidation method of accounting for Belize Electricity, effective June 2011; and (iii) a shift in capital expenditures from 2011 to 2012 related to the timing of payments associated with the Waneta Expansion Project.

An update on significant capital projects for 2011 from that disclosed in the MD&A as at December 31, 2010 is provided below.

FEVI's construction of the estimated $212 million 1.5 billion-cubic foot LNG storage facility at Mount Hayes on Vancouver Island was completed in the second quarter of 2011 and was brought online in late 2011. The storage facility provides a reliable, cost-competitive means of storing gas close to customers, while reducing the dependence on out-of-province storage facilities. The facility provides greater flexibility to meet customer needs during winter months when demand for natural gas is at its highest and meet planned and unplanned system interruptions.

FEI's Customer Care Enhancement Project, at an estimated total project cost of $110 million, was put into service in January 2012. The Company estimates approximately $30 million of the project cost to be incurred in the first half of 2012 related to final contractor payments with the total project cost expected to come in under budget. The project entailed the insourcing of core elements of FEI's customer care services, including two company-owned call centres and billing operations, and implementation of a new customer information system. The BCUC approved the project upon the Company's acceptance of a cost risk-sharing condition, whereby FEI agreed to equally share with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost.

FortisBC Electric's $105 million Okanagan Reinforcement Project was substantially completed in the fall of 2011. The project related to upgrading the existing overhead transmission line between Penticton and Vaseux Lake, near Oliver, from 161 kilovolts ("kV") to a double-circuit 230-kV line and building a new 230-kV terminal substation in the Oliver area.

The Fraser River South Bank South Arm Rehabilitation Project involved the installation and replacement of underwater transmission pipeline crossings that were at potential risk of failure from a major seismic event. During 2010 difficulties were experienced with one of the directional drills delaying the project that was subsequently completed and came into service in 2011, rather than in 2010 as originally expected, at an estimated total cost of approximately $36 million.

During the first quarter of 2011, FortisAlberta substantially completed its $126 million Automated Metering Project, which involved the replacement of approximately 477,000 conventional meters.

During 2011 FortisAlberta continued with the replacement of vintage poles under its Pole Management Program, which involves 96,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through to 2019 is now expected to be approximately $335 million, an increase from the $283 million forecast as at December 31, 2010. The increase is primarily due to a revised forecast estimating higher labour and material costs later in the program and a change in the program scope to include minor-line rebuilds.

Fortis Turks and Caicos had an agreement with a supplier to purchase two diesel-powered generating units, each with a capacity of 9 MW. The units were delivered in 2010 and 2011. Assuming demand for additional generating capacity in 2014, an additional 9-MW unit is forecast for delivery at an estimated cost of approximately $8 million (US$8 million). An agreement for the additional unit has not yet been formalized as it is dependent on future demand trends.

In August 2011 Fortis Properties received municipal government approval to construct a $47 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature 152,000 square feet of Class A office space and include 261 parking spaces. Construction is expected to be completed in the second half of 2013.

Construction progress on the $900 million 335-MW Waneta Expansion Project, in partnership with Columbia Power Corporation and Columbia Basin Trust, is going well and the project is currently on schedule. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Major construction activities on-site include excavation of the intake, powerhouse and power tunnels. Approximately $244 million has been spent on this project since construction began late 2010. The Waneta Expansion Project will be included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy, for the Waneta Expansion Project will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, is expected to be sold to FortisBC Electric under a long-term capacity purchase agreement.

Over the five-year period 2012 through 2016, consolidated gross capital expenditures are expected to be approximately $5.5 billion. Approximately 64% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital spending is expected to be incurred at the regulated gas utilities and at the non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, 39% of utility capital spending is expected to be incurred to meet customer growth; 38% is expected to be incurred to ensure continued and enhanced performance, reliability and safety of generation, transmission and distribution assets (i.e., sustaining capital expenditures); and 23% is expected to be incurred for facilities, equipment, vehicles, information technology and other assets.

A breakdown of forecast gross consolidated capital expenditures by segment for 2012 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year Ending December 31, 2012
($ millions)

FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean**	**Non-Regulated - Utility** [(3)]	**Fortis Properties**	**Total**
244	419	111	82	61	**917**	**55**	**256**	**63**	**1,291**

(1) Relates to forecast cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as would be reflected in the consolidated statement of cash flows. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012. Excludes forecast capitalized amortization and non-cash equity component of AFUDC.

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

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

Significant individual capital projects for 2012 include the continuation of the construction of the non-regulated Waneta Expansion Project for $254 million and the 12-storey office building in St. John's, Newfoundland for $32 million, as well as the continued replacement of vintage poles under FortisAlberta's Pole Management Program for $27 million.

CREDIT FACILITIES

As at December 31, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which $1.9 billion was unused, including the Corporation's unused $800 million committed revolving credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.1 billion of the total credit facilities are committed facilities with maturities ranging from 2012 to 2015.

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

Credit Facilities (Unaudited) *($ millions)*	Corporate and Other	Regulated Utilities	Fortis Properties	**As at December 31, 2011**	As at December 31, 2010
Total credit facilities	845	1,390	13	**2,248**	2,109
Credit facilities utilized:					
Short-term borrowings	-	(157)	(2)	**(159)**	(358)
Long-term debt (including current portion)	-	(74)	-	**(74)**	(218)
Letters of credit outstanding	(1)	(65)	-	**(66)**	(124)
Credit facilities unused	844	1,094	11	**1,949**	1,409

FUTURE ACCOUNTING CHANGES

Adoption of New Accounting Standards: Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board, Fortis has evaluated the option of adopting US GAAP, as opposed to International Financial Reporting Standards ("IFRS"), and has decided to adopt US GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the Ontario Securities Commission ("OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently refers to US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

During the fourth quarter of 2010, the Corporation developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

Phase I - Scoping and Diagnostics: Phase I consisted of project initiation and awareness, project planning and resourcing, and identification of high-level differences between US GAAP and Canadian GAAP in order to highlight areas where detailed analysis would be needed to determine and conclude as to the nature and extent of financial statement impacts. External accounting and legal advisors were engaged during this phase to assist the Corporation's internal US GAAP conversion team and to provide technical input and expertise as required. Phase I commenced in the fourth quarter of 2010 and was completed during 2011.

Phase II - Analysis and Development: Phase II consisted of detailed diagnostics and evaluation of the financial statement impacts of adopting US GAAP based on the high-level assessment conducted under Phase I; identification and design of any new, or changes to, operational or financial business processes; initial staff training and audit committee orientation; and development of required solutions to address identified issues.

Phase II had included planned activities for the registration of securities as required to achieve SEC Issuer status and an assessment of ongoing requirements of the US *Sarbanes-Oxley Act* ("US SOX"), including auditor attestation of internal controls over financial reporting, and a comparison of the requirements under US SOX to those required in Canada under National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. These activities were no longer required or applicable as a result of the Exemption granted by the OSC as discussed above.

Phase II of the plan commenced in January 2011 and was essentially completed during 2011. Based on the research and analysis completed to date, and the Corporation's continued ability to apply rate-regulated accounting policies under US GAAP, the differences between US GAAP and Canadian GAAP are not expected to have a material impact on consolidated earnings. In addition, adoption of US GAAP is expected to result in limited changes in balance sheet classifications and result in additional disclosure requirements. The impact on information systems and internal controls over financial reporting is expected to be minimal.

Phase III - Implementation and Review: Phase III is currently ongoing and has involved the implementation of financial reporting systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements in accordance with US GAAP beginning in 2012, and the communication of associated impacts.

The Corporation will prepare and file its audited Canadian GAAP consolidated financial statements for the year ended December 31, 2011 in the usual manner. The Corporation then intends to voluntarily prepare and file audited US GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives. The Corporation's voluntary filing of audited US GAAP consolidated financial statements for the year ended December 31, 2011, subsequent to the filing of its audited Canadian GAAP consolidated financial statements for the year ended December 31, 2011, has been approved by the OSC and is expected to be completed by March 31, 2012. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared and filed in accordance with US GAAP.

Phase III will conclude when the Corporation files its annual audited consolidated financial statements for the year ending December 31, 2012 prepared in accordance with US GAAP.

Financial Statement Impacts - US GAAP: The areas identified to date where differences between US GAAP and Canadian GAAP are expected to have the most significant financial statement impacts are outlined below. The identified impacts are unaudited and are subject to change based on further analysis.

Employee future benefits: Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit plans is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded or unfunded status being disclosed in the notes to the consolidated financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains and losses and transitional obligations which have not yet been recognized.

US GAAP requires recognition of the funded status of defined benefit plans on the balance sheet. Unamortized balances related to past service costs, actuarial gains and losses and transitional obligations or assets are separately recognized on the balance sheet as a component of accumulated other comprehensive income or, in the case of entities with activities subject to rate regulation, as regulatory assets or liabilities for recovery from, or refund to, customers in future rates. Subsequent changes to past service costs, actuarial gains and losses and transitional obligations would be recognized as part of pension expense, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation's rate-regulated subsidiaries will recognize the funded status of their defined benefit pension plans on the balance sheet with the above-noted unamortized balances recognized as regulatory assets or liabilities.

US GAAP also requires that OPEB costs be recorded on an accrual basis, and prohibits the recognition of regulatory assets or liabilities associated with OPEB costs that are recovered on a cash basis. FortisAlberta has historically recovered its OPEB costs on a cash basis, as opposed to an accrual basis, and will likely continue to do so as ordered by its regulator. Therefore, FortisAlberta's regulatory asset associated with OPEB costs does not meet the criteria for recognition under US GAAP. Historically, Newfoundland Power had also recovered its OPEB costs on a cash basis. However, in December 2010, the regulator approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset associated with the adoption of accrual accounting over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the regulator for rate-setting purposes. The rules under US GAAP related to accounting for OPEBs by rate-regulated entities require that Newfoundland Power de-recognize its OPEB regulatory asset as at January 1, 2010 on the premise that, as at that date, Newfoundland Power was recovering its OPEB costs on a cash basis. However, the regulatory asset will be re-recognized through earnings in accordance with US GAAP in 2010 based on the regulator's approval of Newfoundland Power's application to adopt the accrual method of accounting for OPEBs effective January 1, 2011 and to recover the associated transitional regulatory asset over a 15-year period.

Additional differences between Canadian GAAP and US GAAP in terms of accounting for defined benefit plans include the determination of the measurement date and the attribution period over which pension expense is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end. However, US GAAP requires the entity's fiscal year end to be used as the measurement date. Canadian GAAP also allows for the use of an attribution period for defined benefit pension plans, under specific circumstances, that extends beyond the date when the credited service period ends. However, US GAAP allows for the use of an attribution period for defined benefit pension plans up to the date when credited service ends. The differences are expected to impact the calculation of the Corporation's consolidated benefit obligation, which will be mostly offset by a corresponding change to regulatory assets or liabilities.

With the exception of a one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its ability to subsequently re-recognize this OPEB regulatory asset through earnings in 2010, the impact of adopting US GAAP with respect to accounting for employee future benefits is not expected to have a material impact on the Corporation's consolidated earnings.

Brilliant Power Purchase Agreement ("BPPA"): FortisBC Electric expects that its BPPA will be accounted for as a capital lease under US GAAP. While the requirement to evaluate whether an arrangement includes a lease is similar between Canadian GAAP and US GAAP, the effective date for prospective adoption of lease accounting guidance differs, resulting in an accounting difference with respect to the BPPA.

Fulfillment of the BPPA is dependent on the use of a specific asset, the Brilliant Hydroelectric Plant ("Brilliant"), and the conveyance unto FortisBC Electric of the right to use that asset under an arrangement between FortisBC Electric and the legal owner of Brilliant. The BPPA qualifies as a capital lease as the present value of the minimum lease payments to be made by FortisBC Electric represents recovery of the entire amount of the initial investment in Brilliant by the legal owner over the term of the arrangement.

The anticipated effect of retrospectively recognizing Brilliant as a capital lease upon adoption of US GAAP includes the recognition on the consolidated balance sheet of a utility capital asset with a corresponding capital lease obligation for an equivalent amount. Each subsequent reporting period, the total amount of amortization and interest expense to be recognized under capital lease accounting is expected to differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the BCUC. This timing difference is expected to be recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA.

Since US GAAP allows for entities to account for the effects of rate regulation, the impact of adopting capital lease accounting for Brilliant is not expected to affect the Corporation's consolidated earnings.

Lease-In Lease-Out ("LILO") Transactions: FEI had entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. Under Canadian GAAP, the lease of the assets to the municipalities has been accounted for as a sales-type lease and the lease back of the assets as an operating lease. Gains recorded on the lease out of the assets were deferred and are being amortized over the term of the lease back arrangements.

Under US GAAP, the natural gas distribution assets are considered to be equipment integral to FEI's operations and, therefore, must be evaluated as a real estate sale-leaseback transaction. As a result of this evaluation, the transaction is required to be accounted for as a financing transaction under US GAAP. Under the financing method, the assets subject to the sale-leaseback arrangement are to be recorded as utility capital assets on the Corporation's consolidated balance sheet and subsequently depreciated. Sale proceeds received are recorded as long-term debt. Lease payments, less the portion considered to be interest expense, decrease the long-term debt. The deferred gains, and amortization thereof, which were recorded in accordance with Canadian GAAP are not recognized under US GAAP.

The retrospective impact of accounting for FEI's LILO transactions under US GAAP is expected to result in a decrease in opening retained earnings as at January 1, 2010. The impact on the Corporation's consolidated earnings is not expected to be material.

Reclassification of preference shares: Currently, under Canadian GAAP, the Corporation's First Preference Shares, Series C and Series E are classified as long-term liabilities with associated dividends classified as finance charges. Under US GAAP, the First Preference Shares, Series C and Series E do not meet the criteria for recognition as a financial liability. Therefore, upon the adoption of US GAAP, the Corporation will reclassify its First Preference Shares, Series C and Series E from long-term liabilities to shareholders' equity on the consolidated balance sheet. The associated dividends will not be recorded as finance charges on the Corporation's consolidated statement of earnings but, rather, will be recorded as earnings attributable to preference equity shareholders.

Corporate income taxes: Under Canadian GAAP, the Corporation has calculated and recognized corporate income taxes using substantively enacted corporate income tax rates. Under US GAAP, the Corporation is required to calculate and record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of US GAAP, the Corporation will be required to recognize the impact of the difference between enacted tax rates and substantively enacted tax rates related to the calculation of Part VI.1 tax deductions associated with preference share dividends. The retrospective adjustment to recognize the Part VI.1 tax deductions based on enacted corporate income tax rates will result in a reduction in opening retained earnings under US GAAP and annual earnings thereafter. However, the adjustments are expected to reverse once pending Canadian federal legislation is passed and proposed corporate income tax rate changes become enacted.

The above items do not represent a complete list of expected differences between US GAAP and Canadian GAAP and are subject to change. Other less significant differences have also been identified. Analysis also remains ongoing and additional areas where the Corporation's consolidated financial statements could be materially impacted may be identified prior to the Corporation's voluntary preparation and filing of its audited US GAAP consolidated financial statements for the year ended December 31, 2011. A detailed reconciliation between the Corporation's audited Canadian GAAP and US GAAP financial statements for 2011, including 2010 comparatives, will be disclosed as part of that voluntary filing.

The unaudited estimated quantification and reconciliation of the Corporation's consolidated balance sheets as at December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, based on the differences identified to date, may be summarized as follows.

Total assets as at December 31, 2011 are estimated to increase by approximately $597 million (December 31, 2010 - $496 million). The estimated increase is due primarily to expected increases in regulatory assets and utility capital assets in accordance with US GAAP.

Total liabilities as at December 31, 2011 are estimated to increase by approximately $329 million (December 31, 2010 - $226 million). The estimated increase is due primarily to the expected increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP, partially offset by the reclassification of preference shares from liabilities to shareholders' equity.

Shareholders' equity as at December 31, 2011 is estimated to increase by approximately $268 million (December 31, 2010 - $270 million). The estimated increase is due primarily to the expected reclassification of preference shares from liabilities to shareholders' equity in accordance with US GAAP, partially offset by an estimated reduction in retained earnings of approximately $35 million (December 31, 2010 - $28 million), an estimated increase in accumulated other comprehensive loss of approximately $21 million (December 31, 2010 - $14 million) and other miscellaneous reductions in shareholders' equity based on the retrospective application of US GAAP. Approximately half of the reduction in retained earnings results from higher corporate income taxes, as referred to above, and is expected to reverse in a future period once pending Canadian federal income tax legislation is passed and proposed Part VI.1 tax rate changes become enacted.

As previously indicated, and subject to the above referenced one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its subsequent ability to re-recognize this OPEB regulatory asset in 2010, no material adjustments to the Corporation's consolidated earnings are currently expected under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The unaudited estimated quantification and reconciliation of the Corporation's consolidated statements of earnings for the years ended December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, based on the differences identified to date, may be summarized as follows.

Year ended December 31, 2011: Consolidated net earnings to be recognized in accordance with US GAAP are estimated to increase by $10 million (from $356 million to $366 million). The estimated increase is due primarily to the reclassification of preference share dividends totalling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by an expected reduction in earnings attributable to common equity shareholders of approximately $7 million.

Year ended December 31, 2010: Consolidated net earnings to be recognized in accordance with US GAAP, prior to the one-time adjustment to re-recognize Newfoundland Power's OPEB regulatory asset, are estimated to increase by approximately $8 million (from $323 million to $331 million). The estimated increase is due primarily to the reclassification of preference share dividends totaling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by an expected reduction in earnings attributable to common equity shareholders of approximately $9 million.

The one-time, non-recurring adjustment to re-recognize Newfoundland Power's OPEB regulatory asset in 2010 is estimated to increase earnings attributable to common equity shareholders for the year ended December 31, 2010 by approximately $46 million. This adjustment is not expected to impact retained earnings as at December 31, 2010, as compared to retained earnings reported in accordance with Canadian GAAP as at December 31, 2010, as it reverses an adjustment made to derecognize the OPEB regulatory asset upon adoption of US GAAP as at January 1, 2010.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.5 billion over the five-year period 2012 through 2016, should support continuing growth in earnings and dividends.

The Corporation continues to pursue acquisitions for profitable growth, focusing on regulated electric and natural gas utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

FORTIS INC.

Consolidated Financial Statements
For the three and twelve months ended December 31, 2011 and 2010
(Unaudited)

Fortis Inc.

Consolidated Balance Sheets (Unaudited)
As at December 31
(in millions of Canadian dollars)

	2011	2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 89	$ 109
Accounts receivable	644	655
Prepaid expenses	19	17
Regulatory assets	210	241
Inventories	134	168
Future income taxes	24	14
	1,120	1,204
Assets held for sale	-	45
Other assets	270	168
Regulatory assets	985	854
Future income taxes	8	16
Utility capital assets	8,687	8,185
Income producing properties	594	560
Intangible assets	341	324
Goodwill	1,557	1,553
	$ 13,562	$ 12,909
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 159	$ 358
Accounts payable and accrued charges	914	953
Dividends payable	60	54
Income taxes payable	33	30
Regulatory liabilities	43	60
Current installments of long-term debt and capital lease obligations	106	56
Future income taxes	5	6
	1,320	1,517
Other liabilities	323	308
Regulatory liabilities	558	467
Future income taxes	685	629
Long-term debt and capital lease obligations	5,679	5,609
Preference shares	320	320
	8,885	8,850
Shareholders' equity		
Common shares	3,032	2,578
Preference shares	592	592
Contributed surplus	14	12
Equity portion of convertible debentures	-	5
Accumulated other comprehensive loss	(74)	(94)
Retained earnings	905	804
	4,469	3,897
Non-controlling interests	208	162
	4,677	4,059
	$ 13,562	$ 12,909

Fortis Inc.
Consolidated Statements of Earnings (Unaudited)
For the periods ended December 31
(in millions of Canadian dollars, except per share amounts)

	Quarter Ended		Year Ended	
	2011	2010	**2011**	2010
Revenue	**$ 1,037**	$ 1,034	**$ 3,747**	$ 3,657
Expenses				
Energy supply costs	**490**	507	**1,697**	1,686
Operating	**237**	228	**865**	822
Amortization	**108**	103	**419**	410
	835	838	**2,981**	2,918
Operating income	**202**	196	**766**	739
Other income (expenses), net	**6**	6	**40**	13
Finance charges	**90**	89	**370**	362
Earnings before corporate taxes	**118**	113	**436**	390
Corporate taxes	**23**	19	**80**	67
Net earnings	**$ 95**	$ 94	**$ 356**	$ 323
Net earnings attributable to:				
Non-controlling interests	**$ 2**	$ 2	**$ 9**	$ 10
Preference equity shareholders	**7**	7	**29**	28
Common equity shareholders	**86**	85	**318**	285
	$ 95	$ 94	**$ 356**	$ 323
Earnings per common share				
Basic	**$ 0.46**	$ 0.49	**$ 1.75**	$ 1.65
Diluted	**$ 0.45**	$ 0.47	**$ 1.74**	$ 1.62

Fortis Inc.
Consolidated Statements of Retained Earnings (Unaudited)
For the periods ended December 31
(in millions of Canadian dollars)

	Quarter Ended		Year Ended	
	2011	2010	**2011**	2010
Balance, beginning of period	**$ 877**	$ 770	**$ 804**	$ 763
Net earnings attributable to common and preference equity shareholders	**93**	92	**347**	313
	970	862	**1,151**	1,076
Dividends on common shares	**(58)**	(51)	**(217)**	(244)
Dividends on preference shares classified as equity	**(7)**	(7)	**(29)**	(28)
Balance, end of period	**$ 905**	$ 804	**$ 905**	$ 804

Fortis Inc.

Consolidated Statements of Comprehensive Income (Unaudited)

For the periods ended December 31

(in millions of Canadian dollars)

	Quarter Ended		Year Ended	
	2011	2010	**2011**	2010
Net earnings	**$ 95**	$ 94	**$ 356**	$ 323
Other comprehensive (loss) income				
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**(18)**	(20)	**10**	(33)
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**17**	17	**(10)**	25
Corporate tax (expense) recovery	**(2)**	(3)	**2**	(4)
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(3)**	(6)	**2**	(12)
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity	**-**	-	**17**	-
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax	**-**	-	**1**	1
	(3)	(6)	**20**	(11)
Comprehensive income	**$ 92**	$ 88	**$ 376**	$ 312
Comprehensive income attributable to:				
Non-controlling interests	**$ 2**	$ 2	**$ 9**	$ 10
Preference equity shareholders	**7**	7	**29**	28
Common equity shareholders	**83**	79	**338**	274
	$ 92	$ 88	**$ 376**	$ 312

Fortis Inc.

Consolidated Statements of Cash Flows (Unaudited)
For the periods ended December 31
(in millions of Canadian dollars)

	Quarter Ended		Year Ended	
	2011	2010	**2011**	2010
Operating activities				
Net earnings	**$ 95**	$ 94	**$ 356**	$ 323
Items not affecting cash:				
Amortization - utility capital assets and income producing properties	**98**	92	**380**	368
Amortization - intangible assets	**11**	10	**42**	40
Amortization - other	**(1)**	1	**(3)**	2
Future income taxes	**1**	(2)	**4**	(3)
Accrued employee future benefits	**5**	3	**18**	8
Equity component of allowance for funds used during construction	**(4)**	(5)	**(13)**	(15)
Other	**(9)**	(2)	**(4)**	2
Change in long-term regulatory assets and liabilities	**35**	13	**26**	9
	231	204	**806**	734
Change in non-cash operating working capital	**(4)**	(6)	**98**	(2)
	227	198	**904**	732
Investing activities				
Change in other assets and other liabilities	**(47)**	(1)	**(52)**	-
Capital expenditures - utility capital assets	**(339)**	(336)	**(1,086)**	(1,008)
Capital expenditures - income producing properties	**(10)**	(5)	**(30)**	(19)
Capital expenditures - intangible assets	**(19)**	(29)	**(58)**	(46)
Contributions in aid of construction	**26**	26	**75**	67
Proceeds on sale of utility capital assets and income producing properties	**45**	12	**51**	15
Business acquistion, net of cash acquired	**(25)**	-	**(25)**	-
	(369)	(333)	**(1,125)**	(991)
Financing activities				
Change in short-term borrowings	**(84)**	(52)	**(198)**	(56)
Proceeds from long-term debt, net of issue costs	**304**	523	**343**	523
Repayments of long-term debt and capital lease obligations	**(12)**	(114)	**(36)**	(329)
Net (repayments) borrowings under committed credit facilities	**(40)**	(185)	**(145)**	8
Advances from non-controlling interests	**4**	44	**81**	45
Issue of common shares, net of costs and dividends reinvested	**4**	7	**345**	22
Issue of preference shares, net of costs	**-**	-	**-**	242
Dividends				
Common shares, net of dividends reinvested	**(42)**	(33)	**(151)**	(135)
Preference shares	**(7)**	(7)	**(29)**	(28)
Subsidiary dividends paid to non-controlling interests	**(3)**	(3)	**(9)**	(9)
	124	180	**201**	283
Effect of exchange rate changes on cash and cash equivalents	**(1)**	-	**-**	-
Change in cash and cash equivalents	**(19)**	45	**(20)**	24
Cash and cash equivalents, beginning of period	**108**	64	**109**	85
Cash and cash equivalents, end of period	**$ 89**	$ 109	**$ 89**	$ 109

SEGMENTED INFORMATION (Unaudited)

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Quarter Ended December 31, 2011 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**477**	102	81	156	84	**423**	**70**	**9**	**58**	**7**	**(7)**	**1,037**
Energy supply costs	**264**	-	22	103	55	**180**	**46**	**-**	**-**	**-**	**-**	**490**
Operating expenses	**88**	37	25	20	15	**97**	**9**	**2**	**39**	**3**	**(1)**	**237**
Amortization	**30**	34	11	11	6	**62**	**8**	**1**	**5**	**2**	**-**	**108**
Operating income	**95**	31	23	22	8	**84**	**7**	**6**	**14**	**2**	**(6)**	**202**
Other income (expenses), net	**2**	2	-	-	-	**2**	**1**	**-**	**-**	**1**	**-**	**6**
Finance charges	**30**	16	10	9	4	**39**	**4**	**-**	**6**	**17**	**(6)**	**90**
Corporate tax expense (recovery)	**16**	-	2	4	-	**6**	**-**	**1**	**3**	**(3)**	**-**	**23**
Net earnings (loss)	**51**	17	11	9	4	**41**	**4**	**5**	**5**	**(11)**	**-**	**95**
Non-controlling interests	**-**	-	-	1	-	**1**	**1**	**-**	**-**	**-**	**-**	**2**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**7**	**-**	**7**
Net earnings (loss) attributable to common equity shareholders	**51**	17	11	8	4	**40**	**3**	**5**	**5**	**(18)**	**-**	**86**
Goodwill	**908**	227	221	-	63	**511**	**138**	**-**	**-**	**-**	**-**	**1,557**
Identifiable assets	**4,408**	2,452	1,320	1,202	658	**5,632**	**718**	**542**	**614**	**482**	**(391)**	**12,005**
Total assets	**5,316**	2,679	1,541	1,202	721	**6,143**	**856**	**542**	**614**	**482**	**(391)**	**13,562**
Gross capital expenditures [(1)]	**74**	163	24	26	14	**227**	**14**	**43**	**10**	**-**	**-**	**368**
Quarter Ended December 31, 2010 *($ millions)*												
Revenue	**479**	99	73	152	87	**411**	**84**	**9**	**57**	**7**	**(13)**	**1,034**
Energy supply costs	**277**	-	23	102	59	**184**	**52**	**-**	**-**	**-**	**(6)**	**507**
Operating expenses	**87**	37	21	15	12	**85**	**13**	**1**	**38**	**4**	**-**	**228**
Amortization	**27**	32	10	12	5	**59**	**9**	**1**	**5**	**2**	**-**	**103**
Operating income	**88**	30	19	23	11	**83**	**10**	**7**	**14**	**1**	**(7)**	**196**
Other income (expenses), net	**3**	1	1	-	-	**2**	**1**	**1**	**-**	**-**	**(1)**	**6**
Finance charges	**31**	14	9	9	5	**37**	**6**	**1**	**6**	**16**	**(8)**	**89**
Corporate tax expense (recovery)	**15**	-	1	4	1	**6**	**-**	**1**	**1**	**(4)**	**-**	**19**
Net earnings (loss)	**45**	17	10	10	5	**42**	**5**	**6**	**7**	**(11)**	**-**	**94**
Non-controlling interests	**-**	-	-	1	-	**1**	**1**	**-**	**-**	**-**	**-**	**2**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**7**	**-**	**7**
Net earnings (loss) attributable to common equity shareholders	**45**	17	10	9	5	**41**	**4**	**6**	**7**	**(18)**	**-**	**85**
Goodwill	**908**	227	221	-	63	**511**	**134**	**-**	**-**	**-**	**-**	**1,553**
Identifiable assets	**4,319**	2,144	1,263	1,197	646	**5,250**	**779**	**344**	**576**	**505**	**(417)**	**11,356**
Total assets	**5,227**	2,371	1,484	1,197	709	**5,761**	**913**	**344**	**576**	**505**	**(417)**	**12,909**
Gross capital expenditures [(1)]	**71**	121	40	22	15	**198**	**19**	**77**	**5**	**-**	**-**	**370**

[(1)] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows

SEGMENTED INFORMATION (Unaudited) (cont'd)

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Annual **December 31, 2011** *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,568**	409	296	573	339	**1,617**	**305**	**34**	**231**	**29**	**(37)**	**3,747**
Energy supply costs	**854**	-	72	369	218	**659**	**192**	**1**	**-**	**-**	**(9)**	**1,697**
Operating expenses	**307**	144	83	75	48	**350**	**40**	**8**	**156**	**10**	**(6)**	**865**
Amortization	**111**	134	45	42	24	**245**	**33**	**4**	**19**	**7**	**-**	**419**
Operating income	**296**	131	96	87	49	**363**	**40**	**21**	**56**	**12**	**(22)**	**766**
Other income (expenses), net	**10**	5	1	-	-	**6**	**3**	**1**	**-**	**21**	**(1)**	**40**
Finance charges	**127**	60	39	36	20	**155**	**14**	**2**	**24**	**71**	**(23)**	**370**
Corporate tax expense (recovery)	**40**	1	10	16	7	**34**	**1**	**2**	**9**	**(6)**	**-**	**80**
Net earnings (loss)	**139**	75	48	35	22	**180**	**28**	**18**	**23**	**(32)**	**-**	**356**
Non-controlling interests	**-**	-	-	1	-	**1**	**8**	**-**	**-**	**-**	**-**	**9**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**29**	**-**	**29**
Net earnings (loss) attributable to common equity shareholders	**139**	75	48	34	22	**179**	**20**	**18**	**23**	**(61)**	**-**	**318**
Goodwill	**908**	227	221	-	63	**511**	**138**	**-**	**-**	**-**	**-**	**1,557**
Identifiable assets	**4,408**	2,452	1,320	1,202	658	**5,632**	**718**	**542**	**614**	**482**	**(391)**	**12,005**
Total assets	**5,316**	2,679	1,541	1,202	721	**6,143**	**856**	**542**	**614**	**482**	**(391)**	**13,562**
Gross capital expenditures [1]	**253**	416	102	81	47	**646**	**71**	**174**	**30**	**-**	**-**	**1,174**
Annual **December 31, 2010** *($ millions)*												
Revenue	**1,546**	385	266	555	331	**1,537**	**333**	**36**	**226**	**29**	**(50)**	**3,657**
Energy supply costs	**863**	-	73	358	215	**646**	**201**	**1**	**-**	**-**	**(25)**	**1,686**
Operating expenses	**288**	141	73	62	45	**321**	**48**	**9**	**151**	**10**	**(5)**	**822**
Amortization	**108**	126	41	47	23	**237**	**36**	**4**	**18**	**7**	**-**	**410**
Operating income	**287**	118	79	88	48	**333**	**48**	**22**	**57**	**12**	**(20)**	**739**
Other income (expenses), net	**9**	3	3	-	-	**6**	**3**	**4**	**-**	**(5)**	**(4)**	**13**
Finance charges	**121**	54	35	36	21	**146**	**18**	**4**	**24**	**73**	**(24)**	**362**
Corporate tax expense (recovery)	**45**	(1)	5	16	8	**28**	**1**	**2**	**7**	**(16)**	**-**	**67**
Net earnings (loss)	**130**	68	42	36	19	**165**	**32**	**20**	**26**	**(50)**	**-**	**323**
Non-controlling interests	**-**	-	-	1	-	**1**	**9**	**-**	**-**	**-**	**-**	**10**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**28**	**-**	**28**
Net earnings (loss) attributable to common equity shareholders	**130**	68	42	35	19	**164**	**23**	**20**	**26**	**(78)**	**-**	**285**
Goodwill	**908**	227	221	-	63	**511**	**134**	**-**	**-**	**-**	**-**	**1,553**
Identifiable assets	**4,319**	2,144	1,263	1,197	646	**5,250**	**779**	**344**	**576**	**505**	**(417)**	**11,356**
Total assets	**5,227**	2,371	1,484	1,197	709	**5,761**	**913**	**344**	**576**	**505**	**(417)**	**12,909**
Gross capital expenditures [1]	**253**	379	139	78	48	**644**	**72**	**84**	**19**	**1**	**-**	**1,073**

[1] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows

CORPORATE INFORMATION

Fortis Inc. is the largest investor-owned distribution utility in Canada, with total assets of approximately $13.6 billion and fiscal 2011 revenue totalling approximately $3.8 billion. The Corporation serves more than 2,000,000 gas and electricity customers. Its regulated holdings include electric distribution utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia. Fortis owns and operates non-regulated generation assets across Canada and in Belize and Upper New York State. It also owns hotels and commercial office and retail space in Canada.

The Common Shares, First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis are traded on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

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Additional information, including the Fortis 2010 Annual Information Form, Management Information Circular and Annual Report, are available on SEDAR at www.sedar.com and on the Corporation's web site at www.fortisinc.com.

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