FortisBC Energy Inc.
Management Discussion & Analysis
For the Three and Nine Months Ended September 30, 2013
Dated November 1, 2013

The following FortisBC Energy Inc. ("FEI" or the "Corporation") Management Discussion & Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. Financial information for 2013 and comparative periods contained in the following MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified. The MD&A should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto for the three and nine months ended September 30, 2013, with 2012 comparatives, prepared in accordance with US GAAP and the annual audited consolidated financial statements and notes thereto together with the MD&A for the year ended December 31, 2012, with 2011 comparatives, prepared in accordance with US GAAP.

In this MD&A, FEVI refers to FortisBC Energy (Vancouver Island) Inc., FEW refers to FortisBC Energy (Whistler) Inc., FAES refers to FortisBC Alternative Energy Services Inc., FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., and Fortis refers to the Corporation's ultimate parent, Fortis Inc.

FORWARD LOOKING STATEMENT

Certain statements in this MD&A contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). 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 in this MD&A includes, but is not limited to, statements regarding the Corporation's expectations to meet interest payments on outstanding indebtedness from internally generated funds; the Corporation's expected level of capital expenditures and its expectations to finance those capital expenditures through credit lines, debt issues, equity contributions and internally generated funds; the Corporation's expectations for employee future benefit costs; the Corporation's belief that changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts and the forecast average rate base for 2014.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; absence of administrative monetary penalties; the ability to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2014; absence of equipment breakdown; absence of environmental damage and health and safety issues; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; the First Nations' settlement process does not adversely affect the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefits costs; the ability of the Corporation to attract and retain skilled workforces; absence of information technology infrastructure failure; continued energy demand; the ability to arrange sufficient and cost effective financing; no material adverse ratings actions by credit ratings agencies; the competitiveness of natural gas pricing when compared with alternate sources of energy; continued population growth and new housing starts; the availability of natural gas supply; and the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); transition to new accounting standards risk; equipment breakdown, operating and maintenance risk; environment, health and safety matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses risk; First Nations risk; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; interest rate risk; impact of

changes in economic conditions risk; capital resources and liquidity risk; competiveness and commodity price risk; counterparty credit risk; natural gas supply risk; and, other risks described in the Corporation's most recent Annual Information Form. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A and the Corporation's MD&A for the year ended December 31, 2012.

All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement 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

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 842,000 residential, commercial and industrial and transportation customers in more than 100 communities. Major areas served by the Corporation are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of the province. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

The Corporation is an indirect, wholly-owned subsidiary of Fortis, a diversified, international distribution utility holding corporation having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

REGULATION

Customer Rates, Quarterly Gas Cost Changes and Regulatory Applications

Customer rates include both the delivery charge, and the commodity and midstream charges. The commodity cost of natural gas and midstream costs are flowed through to customers without mark-up.

In addition to annual delivery rate changes, the Corporation reviews natural gas and propane commodity and midstream charges every three months with the British Columbia Utilities Commission ("BCUC") in order to ensure the rates charged to customers are sufficient to cover the cost of purchasing natural gas and contracting for midstream resources such as third-party pipeline or storage capacity.

Overall, residential rates increased in the third quarter of 2013 as compared to the third quarter of 2012. The table below shows the rate changes since January 1, 2012 for a typical Lower Mainland residential customer:

	2012					**2013**		
	Jan 1	April 1	June 1	July 1	Oct 1	**Jan 1**	**April 1**	**July 1**
Effective rate per gigajoule	$10.39	$9.36	$9.21	$9.21	$9.21	**$9.36**	**$9.36**	**$10.00**
Percentage change in rate	3.3%	(9.9%)	(1.6%)	-	-	**1.6%**	**-**	**6.8%**

When comparing September 30, 2013 to September 30, 2012, an average bill for a FEI residential customer increased by approximately 8.4 per cent, due to increases in both the cost of natural gas and the January 1, 2013 increase in delivery rates.

In February 2012, the BCUC approved a general tariff for FEI to provide compressed natural gas ("CNG") and liquefied natural gas ("LNG") refueling services for transportation vehicles. FEI has received either permanent or interim rate approval for four refueling projects. In addition, FEI has received BCUC approval for rate treatment of expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") under the *Clean Energy Act* ("CEA") that was promulgated in May 2012. In May 2013, FEI filed an application for approval of its first refueling station under the GGRR and received approval of the rates to be charged to customers in July 2013.

The Corporation received a decision on changing its LNG sales and dispensing service rate schedule from a pilot program to a permanent program in June 2013. The decision did not approve the program as permanent, but extended the pilot program until the end of 2020, and set out the rate to be charged.

In August 2011, the Corporation received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for Natural Gas Vehicles ("NGV"). FEI had made these funds available to assist large customers to purchase NGV 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 requested that FEI provide further submissions to determine the prudency of the EEC incentives at a future time. An application was filed with the BCUC to review the prudency of the EEC incentives and a decision was received on April 30, 2013 in which the BCUC determined the EEC incentives for NGV were prudently incurred and can be recovered from natural gas ratepayers, as part of the incentive program funding under the GGRR.

In June 2013, FEI filed an application for a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed on September 6, 2013, the application assumes a forecast average rate base for FEI of approximately $2,789 million for 2014 and requests approval of a delivery rate increase for 2014 of approximately 1.4 per cent determined under a formula approach for operating and capital costs, and a continuation of this rate setting methodology for a further four years. The regulatory process to review the application will continue throughout 2013 and 2014, with a decision expected mid-2014.

In April 2012, the Corporation, together with FEVI and FEW, applied to the BCUC for the necessary approvals to amalgamate and implement postage stamp rates across the service territories served by the amalgamated entity for 2014. The evidentiary portion of the proceeding was closed in October 2012 and a decision was received in February 2013. In its decision, the BCUC denied the request to implement postage stamp rates. On March 27, 2013, the Corporation filed a Notice of Application for Leave to Appeal the decision with the BC Court of Appeal, and on April 26, 2013, the Corporation filed an Application for Reconsideration with the BCUC. In June 2013, the BCUC determined that the reconsideration application would be heard. The regulatory process to review the reconsideration application will be complete in November 2013 and a decision is expected by early 2014.

Allowed Return on Equity ("ROE") and Capital Structure

In February 2012, the BCUC established that a Generic Cost of Capital ("GCOC") Proceeding would occur and in April 2012, issued a final scoping document identifying specific items that would be reviewed as part of the GCOC Proceeding.

Pursuant to a BCUC order released in December 2012, effective January 1, 2013, the approved 2012 ROE and capital structure for the Corporation and all other regulated entities in BC that rely on the benchmark utility, which was determined to be FEI, to establish rates were to be maintained and made interim. In May 2013, the BCUC issued its decision on the first stage of the GCOC Proceeding. The decision determined that the ROE of the benchmark utility would be set at 8.75 per cent with a 38.5 per cent common equity component, both effective January 1, 2013. The common equity component in capital structure will remain in effect through December 31, 2015. Effective January 2014, the BCUC is also introducing an Automatic Adjustment Mechanism ("AAM") to set the ROE on an annual basis for the Corporation. The AAM will take effect when the actual long-term Government of Canada bond yield exceeds 3.8 per cent. The AAM will be in effect until December 31, 2015.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year to date		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
($ millions)						
Revenue	**173**	170	3	**802**	878	(76)
Expenses						
Cost of natural gas	**56**	55	1	**341**	429	(88)
Operation and maintenance	**47**	42	5	**139**	133	6
Depreciation and amortization	**37**	32	5	**110**	96	14
Property and other taxes	**13**	12	1	**39**	37	2
	153	141	12	**629**	695	(66)
Operating income	**20**	29	(9)	**173**	183	(10)
Finance charges	**49**	48	1	**107**	107	-
(Loss) earnings before income taxes	**(29)**	(19)	(10)	**66**	76	(10)
Income taxes	**(12)**	(9)	(3)	**9**	10	(1)
Net (loss) earnings	**(17)**	(10)	(7)	**57**	66	(9)

	Quarter			Year to date		
Periods Ended September 30	**2013**	2012	Variance	**2013**	2012	Variance
Gas sales (Petajoules (PJs))	**22**	24	(2)	**119**	124	(5)

For the three and nine months ended September 30, 2013, gas sales volumes were lower compared to the corresponding periods in 2012 due to lower consumption by residential, commercial and transportation customers as a result of warmer weather.

Net Earnings

As a result of the BCUC's decision on stage one of the GCOC Proceeding received in May of 2013, the allowed ROE for 2013 for the Corporation decreased to 8.75 per cent effective January 1, 2013 from 9.5 per cent in 2012. The deemed equity component for the Corporation decreased to 38.5 per cent effective January 1, 2013 from 40.0 per cent in 2012. The decision decreased net earnings for the three and nine months ended September 30, 2013 by approximately $1 million and $7 million, respectively.

The Corporation reported a net loss of $17 million for the three months ended September 30, 2013 and net earnings of $57 million for the nine months ended September 30, 2013 compared to a net loss of $10 million and net earnings of $66 million, respectively, in the corresponding periods of 2012.

For the three months ended September 30, 2013, the higher net loss was primarily due to higher operation and maintenance expense due to the timing of the expenditures, a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure and lower margin associated with lower than forecast customer additions partially offset by higher rate base.

For the nine months ended September 30, 2013, net earnings were lower primarily due to a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure, higher operation and maintenance expense due to the timing of the expenditures and lower margin associated with lower than forecast customer additions partially offset by higher rate base.

Revenue and Cost of Natural Gas

For the three months ended September 30, 2013, revenues increased by $3 million while for the nine months ended September 30, 2013 revenues decreased by $76 million compared to the corresponding periods in 2012. For the three months ended September 30, 2013, cost of natural gas increased by $1 million while for the nine months ended September 30, 2013 cost of natural gas decreased by $88 million compared to the corresponding periods in 2012.

Higher revenues and cost of natural gas for the three months reflect higher commodity costs compared to the same period in 2012 partially offset by lower gas sales due to warmer weather. The higher revenues for the three months are partially offset by the decrease in the allowed ROE and deemed equity component for 2013 compared to 2012. Lower revenues for the nine months is partially due to the decrease in the allowed ROE and deemed equity component for 2013 compared to 2012 as discussed above. Also, lower revenues and cost of natural gas for the nine months reflect lower gas sales due to warmer weather and lower commodity costs compared to the same period in 2012.

Margin for the three and nine months ended September 30, 2013 was higher compared to the same period in 2012 due to higher rate base partially offset by a lower allowed ROE and deemed equity component and lower margin associated with lower than forecast customer additions.

Changes in consumption levels of sales customers and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

Operation and Maintenance Expense

For the three and nine months ended September 30, 2013, operation and maintenance expense increased by $5 million and $6 million, respectively, compared to the corresponding periods in 2012. The increase in operation and maintenance expense was mainly due to higher contracting costs, higher information technology support costs and the timing of expenditures.

Depreciation and Amortization

As part of the 2012/2013 Revenue Requirements Application ("2012/2013 RRA") decision, the BCUC ordered the Corporation to capture differences between actual depreciation and forecast depreciation in a deferral account.

For the three and nine months ended September 30, 2013, depreciation and amortization expense increased by $5 million and $14 million, respectively, as compared with the corresponding periods in 2012. The increase was primarily due to higher amortization of regulatory deferral accounts and higher depreciation expense in 2013 as approved by the BCUC.

Finance Charges

For the three and nine months ended September 30, 2013, finance charges were comparable to the corresponding periods in 2012 primarily due to borrowings being comparable for the corresponding periods in 2013 and 2012.

Income Taxes

In the third quarter of 2013, the Corporation revised its estimated annual effective tax rate to reflect a change in the Canadian federal and BC provincial combined statutory rate from 25.0 per cent to 26.0 per cent effective April 1, 2013, resulting from legislation enacted in July 2013. Income tax expense reported for both the third quarter and year-to-date periods of 2013 were adjusted to reflect the change in the effective tax rate.

For the three months ended September 30, 2013, income tax recovery increased by $3 million, while for the nine months ended September 30, 2013 income tax expense decreased by $1 million, respectively, compared to the corresponding periods in 2012. The increase in income tax recovery for the three months was mainly due to a larger pre-tax loss. The decrease in income tax expense for the nine months was mainly due to lower pre-tax earnings partially offset by higher taxable permanent differences.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at September 30, 2013 compared to December 31, 2012:

Balance Sheet Item	Increase (Decrease) ($ millions)	Explanation
Accounts receivable	(111)	The decrease was mainly due to a decrease in trade accounts receivable and unbilled receivables due to lower sales volumes as a result of warmer weather during the summer and early fall compared to the winter.
Accounts payable and accrued liabilities	(48)	The decrease was mainly due to a decrease in the mark to market of the Corporation's natural gas derivatives, a decrease in trade payables and a decrease in gas costs payable due to a lower average unit cost partially offset by higher volumes purchased.
Income and other taxes payable	(31)	The decrease was primarily due to a decrease in other taxes including GST, franchise taxes and property taxes.
Regulatory assets	30	The increase was primarily due to the increase in the regulated asset for deferred income taxes, increase in actual pension costs in excess of approved amounts, increase in deferred losses on disposal of utility capital assets and increase in costs related to the energy efficiency and conservation program partially offset by a decrease in the commodity costs reconciliation deferral account.
Property, plant and equipment	24	The increase was primarily due to approximately $99 million in capital expenditures incurred during the period, non-cash capital accruals of $4 million and contributions in aid of construction of approximately $1 million received, partially offset by depreciation expense of $80 million.
Deferred income taxes	32[1]	The increase was primarily due to an increase in tax timing differences relating to capital expenditures and regulatory deferrals, the offset of which has been recognized in regulatory assets. In the third quarter of 2013, the Corporation revised its estimated deferred income tax liabilities to reflect a change in the Canadian federal and BC provincial combined statutory rate from 25.0 per cent to 26.0 per cent effective April 1, 2013, resulting from legislation enacted in July 2013. Deferred income taxes for both the third quarter and year-to-date periods of 2013 were adjusted to reflect this change, which resulted in an increase in deferred income tax liabilities of approximately $17 million, the offset of which has been recognized in regulatory assets.

[1] Net of deferred income tax assets.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Nine Months Ended September 30	**2013**	2012	Variance
($ millions)			
Cash flows provided by (used for):			
Operating activities	**159**	190	(31)
Investing activities	**(107)**	(109)	2
Financing activities	**(71)**	(53)	(18)
Net (decrease) increase in cash and cash equivalents	**(19)**	28	(47)

Operating Activities

Cash flow provided by operating activities for the nine months ended September 30, 2013, which included the impact of changes in non-cash working capital, was $159 million compared to $190 million in the corresponding period of 2012. The decrease in cash provided by operating activities was primarily due to changes in long-term regulatory assets and liabilities and changes in non-cash working capital.

Investing Activities

Cash used for investing activities for the nine months ended September 30, 2013, was $107 million, a decrease of $2 million compared to $109 million used in the same period in 2012. The decrease was primarily due to a decrease in intangible asset expenditures and changes in other assets and long-term liabilities partially offset by higher investment in property, plant and equipment.

Financing Activities

Cash used for financing activities for the nine months ended September 30, 2013 was $71 million, an increase of $18 million compared to the $53 million used in the corresponding period of 2012. The increase in cash used was primarily due to an increase in dividends paid during 2013 compared to the comparable period in 2012 and in the second quarter of 2012 there were proceeds from the issuance of common shares, with no comparable equity issuance in 2013. The increase is partially offset by changes in short-term note borrowings.

Consistent with 2012, during the third quarter of 2013, the Corporation did not pay any common share dividends leaving the year to date common share dividends paid to its parent companies at $84 million (2012 - $50 million).

Contractual Obligations

The following table sets forth the Corporation's contractual obligations due in the years indicated:

As at September 30, 2013	**Total**	**Due Within 1 Year**	**Due in year 2**	**Due in year 3**	**Due in year 4**	**Due in year 5**	**Due after 5 years**
($ millions)							
Interest on long-term debt	1,812	105	105	97	76	76	1,353
Debt retirement and capital lease and finance obligations	1,663	6	81	206	7	7	1,356
Operating leases	17	3	3	3	2	2	4
Gas purchase obligations	242	210	30	2	-	-	-
Employee defined benefit pension plans	3	3	-	-	-	-	-
Totals	3,737	327	219	308	85	85	2,713

Gas purchase contract commitments are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at September 30, 2013.

Capital Structure

The Corporation's principal business of regulated gas transmission and distribution requires ongoing access to capital in order to allow the Corporation to fund the maintenance and expansion of infrastructure. The Corporation maintains a capital structure in line with the deemed capital structure approved by the BCUC at 38.5 per cent equity and 61.5 per cent debt (2012 – 40 per cent equity and 60 per cent debt).

Credit Ratings

In June 2013, Moody's Investors Service affirmed the long-term credit rating of the Corporation of A3 but changed the rating outlook from stable to negative.

There have been no other changes to the Corporation's credit ratings from those reported in the Corporation's 2012 annual MD&A.

Projected Capital Expenditures

The projected capital expenditures for 2013 before contributions in aid of construction and including cost of removal remain substantially unchanged from the description outlined in the Corporation's 2012 annual MD&A.

Cash Flow Requirements

The Corporation's working capital requirements fluctuate seasonally based on natural gas consumption. Given the regulated nature of its business, the Corporation is able to maintain negative working capital balances. The Corporation maintains adequate committed credit facilities and on an annual basis, generates sufficient cash flow to meet its working capital requirements.

It is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flow available for capital expenditures and/or for dividend payments. Cash required to complete capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from FHI and long-term debt issues.

The Corporation's ability to service its debt obligations and pay dividends on its common shares is dependent on the financial results of the Corporation. Depending on the timing of cash payments, borrowings under the Corporation's credit facility may be required from time to time to support the servicing of debt and payment of dividends.

Credit Facilities

As at September 30, 2013, the Corporation had a $500 million syndicated credit facility available of which $400 million was unused. On July 5, 2013, the Corporation extended the maturity of its credit facility to mature on August 24, 2015. The new agreement has substantially similar terms to the facility it replaced.

($ millions)	**September 30, 2013**	December 31, 2012
Total credit facility	**500**	500
Short-term notes	**(50)**	(33)
Letters of credit outstanding	**(50)**	(51)
Credit facility available	**400**	416

OFF-BALANCE SHEET ARRANGEMENTS

As at September 30, 2013, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $50 million (2012 - $51 million).

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent and other related companies under common control to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the three and nine months ended September 30 were as follows:

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2013**	2012	**2013**	2012
Natural gas transmission and distribution revenue recovered from FEVI [(a)]	**1**	1	**3**	3
Operation and maintenance expense charged to FBC [(b)]	**1**	-	**2**	1
Operation and maintenance expense charged to FEVI [(c)]	**2**	2	**7**	7
Operation and maintenance expense charged to FHI [(c)]	-	-	**1**	1
Other income recovered from FHI [(d)]	**19**	19	**19**	19
	23	22	**32**	31

(a) The Corporation charged FEVI, a subsidiary of FHI, for transporting natural gas through the Corporation's pipeline system.

(b) The Corporation charged FBC, an indirect subsidiary of Fortis, for office rent and management services.

(c) The Corporation charged FHI and FEVI for management services, labour and materials.

(d) As part of a tax loss utilization plan ("TLUP"), the Corporation received dividend income from FHI relating to a $1,400 million investment in preferred shares. A TLUP is a series of transactions, whereby the Corporation sets up an investment in an affiliate's preferred shares and issues subordinated debt to that affiliate; these two financial instruments are shown on a net basis. The Corporation receives non-taxable dividend income on the preferred shares and pays tax deductible interest on the debt. The effect of this transaction is to transfer tax losses between affiliated entities.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the three and nine months ended September 30 were as follows:

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2013**	2012	**2013**	2012
Natural gas storage costs charged by FEVI [(a)]	**4**	4	**12**	12
Operation and maintenance expense charged by FBC [(b)]	**1**	1	**3**	2
Operation and maintenance expense charged by FHI [(c)]	**3**	3	**9**	9
Finance charges paid to FHI [(d)]	**19**	19	**19**	19
	27	27	**43**	42

(a) FEVI charged the Corporation for storing natural gas at the Mt. Hayes LNG storage facility. These charges were included in regulatory liabilities on the consolidated balance sheets.

(b) FBC charged the Corporation for electricity purchases and management services.

(c) FHI charged the Corporation for Board of Director costs, management services, labour and materials.

(d) As part of the TLUP described in Related Party Recoveries (d) above, the Corporation paid FHI interest on $1,400 million of inter-company subordinated debt.

Balance Sheet Amounts

As a result of the transactions noted above, the amounts due from related parties, which are included in accounts receivable on the consolidated balance sheets, and the amounts due to related parties which are included in accounts payable and accrued liabilities on the consolidated balance sheets, are as follows:

	September 30, 2013		December 31, 2012	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FEVI	**3**	**-**	2	**-**
FBC	**-**	**1**	-	**-**
	3	**1**	2	**-**

The amounts are unsecured and non-interest bearing.

BUSINESS RISK MANAGEMENT

The business risks of the Corporation remain substantially unchanged from those outlined in the Corporation's 2012 annual MD&A.

CHANGES IN ACCOUNTING POLICIES

The following new US GAAP accounting pronouncement that is applicable to, and was adopted by, the Corporation effective January 1, 2013 is described as follows:

Disclosures About Offsetting Assets and Liabilities

The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet - Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") Nos. 2011-11 and 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The amended disclosures are intended to assist financial statement users in understanding significant quantitative differences between balance sheets prepared under US GAAP and International Financial Reporting Standards. ASU No. 2013-01 limits the scope of the new offsetting disclosure requirements previously issued in ASU No. 2011-11, to certain derivative instruments, repurchase and reverse repurchase agreements, and securities borrowing and lending arrangements that are either offset on the balance sheet or subject to an enforceable master netting or similar arrangement. The above-noted amendments were applied retrospectively and did not impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2013 and 2012.

FINANCIAL INSTRUMENTS

Fair Value Estimates

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas derivative contracts as of September 30, 2013 and December 31, 2012, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value:

	September 30, 2013		December 31, 2012	
($ millions)	**Carrying value**	**Estimated fair value**	Carrying value	Estimated fair value
Long-term debt	**1,545**	**1,857**	1,545	2,039
Natural gas commodity swaps and options and gas purchase contract premium[1]	**5**	**5**	26	26

[1] Included in accounts payable as at September 30, 2013 and December 31, 2012.

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment.

At September 30, 2013, the Corporation's outstanding derivative balances were as follows:

($ millions)	**Gross derivatives balance[1]**	**Netting[2]**	**Cash collateral**	**Total derivatives balance**
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	**5**	**-**	**-**	**5**

[1] See the September 30, 2013 unaudited interim consolidated financial statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.
[2] Positions, by counterparty, are netted where the intent and legal right to offset exists.

At December 31, 2012, the Corporation's outstanding derivative balances were as follows:

($ millions)	Gross derivatives balance[1]	Netting[2]	Cash collateral	Total derivatives balance
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	26	-	-	26

[1] See the December 31, 2012 consolidated financial statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.
[2] Positions, by counterparty, are netted where the intent and legal right to offset exists.

The following table shows the cumulative unrealized losses at September 30, 2013 and December 31, 2012, with respect to the derivative instruments:

($ millions)	**September 30, 2013**	December 31, 2012
Unrealized loss on natural gas commodity derivatives[1,2]	**5**	26

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to current regulatory assets or liabilities rather than being recorded to the consolidated statement of earnings.
[2] These amounts are fully passed through to customers in rates. Accordingly, net earnings were not impacted by realized amounts on these instruments.

CRITICAL ACCOUNTING ESTIMATES

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

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates year-to-date 2013 from those disclosed in the Corporation's 2012 annual MD&A.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2011 through September 30, 2013. The information has been obtained from the Corporation's unaudited interim consolidated financial statements which, in the opinion of management, have been prepared in accordance with US GAAP. Past operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Quarter Ended	**Revenue**	**Net (Loss) Earnings**
($ millions)		
September 30, 2013	173	(17)
June 30, 2013	200	(1)
March 31, 2013	429	75
December 31, 2012	388	46
September 30, 2012	170	(10)
June 30, 2012	223	4
March 31, 2012	485	72
December 31, 2011	438	47

Due to the seasonal nature of the Corporation's natural gas transmission and distribution operations and its impact on, natural gas consumption patterns, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result of the seasonality, interim earnings are not indicative of earnings on an annual basis.

December 2012/2011 – Earnings were lower primarily due to lower margin associated with lower than forecast customer additions in 2012, lower capitalized allowance for funds used during construction compared to the same period in 2011 and timing of operation and maintenance expenditures partially offset by increased rate base, higher margin from industrial customers and higher contribution from the current year tax loss utilization plan.

March 2013/2012 - Earnings have increased quarter over quarter primarily due to higher rate base and higher margin from industrial customers partially offset by lower margin associated with lower than forecast customer additions and higher income taxes.

June 2013/2012 - Earnings were lower primarily due to the retroactive impact of a lower allowed ROE in 2013 compared to 2012, the retroactive impact of the decrease in the equity component of the capital structure, a decrease in margin from industrial customers and lower margin associated with lower than forecast customer additions partially offset by higher rate base and lower income taxes.

September 2013/2012 – The higher net loss was primarily due to higher operation and maintenance expense due to the timing of the expenditures, a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure and lower margin associated with lower than forecast customer additions partially offset by higher rate base.

BUSINESS OUTLOOK

Collective Agreements

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expires on March 31, 2015. IBEW represents employees in specified occupations in the areas of transmission and distribution.

The collective agreement between the Corporation and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expires on March 31, 2015. COPE represents employees in specified occupations in the areas of administration and operations support.

The collective agreement between the Corporation's customer service employees and Local 378 of the COPE expires on March 31, 2014.

Contingencies

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

OUTSTANDING SHARE DATA

As at the filing date of this MD&A the Corporation had issued and outstanding 64,910,782 common shares.

The Corporation is an indirect wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information about FortisBC Energy Inc., including its Annual Information Form, is available on SEDAR at www.sedar.com.

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