FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS
For the Three Months Ended March 31, 2019

April 30, 2019

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 2019 and comparative periods contained in the following MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars. The MD&A should be read in conjunction with the Corporation's Unaudited Condensed Consolidated Interim Financial Statements and notes thereto for the three months ended March 31, 2019, prepared in accordance with US GAAP and the Corporation's Annual Audited Consolidated Financial Statements and notes thereto together with the MD&A for the year ended December 31, 2018, with 2017 comparatives, prepared in accordance with US GAAP.

In this MD&A, FAES refers to FortisBC Alternative Energy Services Inc., FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., ACGS refers to Aitken Creek Gas Storage ULC, 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 estimated costs for the current and future phases of the Tilbury Liquefied Natural Gas Facility Expansion Project ("Tilbury Expansion Project"), the Lower Mainland Intermediate Pressure System Upgrade Project ("LMIPSU"), the Inland Gas Upgrades Project ("IGU") and their associated in-service dates; the expected date of the British Columbia Utility Commission's decision in response to the Corporation's Multi-year Rate Plan application (the "MRP Application"); the Corporation's expected level of capital expenditures and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; the Corporation's estimated contractual obligations; and the final investment decision, in-service date and estimated costs associated with the pipeline expansion to the proposed Eagle Mountain Woodfibre Liquefied Natural Gas ("Woodfibre LNG") site; and the effect of the Westcoast Energy Inc. ("Westcoast") natural gas transmission pipeline incident.

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 continue to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2023 or earlier; absence of asset 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; no adverse effect of the Indigenous peoples' settlement process on the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain a skilled workforce; absence of information technology infrastructure failure; absence of cyber-security failure; continued energy demand; the ability to arrange sufficient and cost effective financing; no material adverse rating actions by credit rating 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); continued reporting in accordance with US GAAP risk; asset breakdown, operation, maintenance and expansion risk; environment, health and safety matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving Indigenous peoples; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competitiveness and commodity price risk; counterparty credit risk; natural gas supply and weather related risks; and other risks described in the Corporation's most recent Annual Information Form ("AIF"). For additional information with respect to these risk factors, reference should be made to the Corporation's MD&A and AIF for the year ended December 31, 2018.

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 1,033,000 residential, commercial, industrial, and transportation customers in more than 135 communities. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential, commercial, and industrial 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 leader in the North American electric and natural gas utility business. Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

REGULATION

Customer Rates and Deferral Mechanisms

Customer rates include both the delivery charge and the cost of natural gas. The cost of natural gas, consisting of the commodity, storage and transport costs, is passed through to customers without mark-up. The Corporation's customer rates are based on estimates and forecasts. In order to manage the risk of forecast error associated with some of these estimates and to manage volatility in rates, a number of regulatory deferral accounts are in place. These deferral mechanisms decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the significant impacts of weather and other changes on customer use rates.

Variances from regulated forecasts used to set rates for natural gas revenue are flowed back to customers in future rates through approved regulatory deferral mechanisms and therefore these variances do not have an impact on net earnings in either 2019 or 2018. As part of FEI's Multi-year Performance Based Ratemaking Plan for the years 2014 to 2019 ("PBR Application"), the Corporation has a flow-through deferral account that captures variances from regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.

The Midstream Cost Reconciliation Account ("MCRA") deferral mechanism captured the increased cost of procuring additional gas on the open marketplace to replace the gas that was not received due to an incident that took place on October 9, 2018. The incident affected Westcoast's natural gas transmission pipeline, near Prince George, BC, which provides supply of natural gas to FEI for distribution to its customers in various locations across BC. Westcoast is a wholly-owned subsidiary of Enbridge Inc. FEI declared a force majeure under several of its rate schedules. No FEI infrastructure was damaged as a result of this incident. FEI recovers the costs captured in the MCRA deferral account through customer rates. Insurance recoveries, if any, associated with the incident would reduce the amount recoverable from customers.

Performance Based Ratemaking Plan for 2014 to 2019

In September 2014, the British Columbia Utilities Commission ("BCUC") issued its decision on FEI's PBR Application setting out the rate-setting framework for the years 2014 to 2019.

In the first quarter of 2019, the BCUC issued its decision on FEI's 2019 delivery rates. The decision resulted in a 2019 average rate base of approximately $4,497 million, excluding the rate base of approximately $12 million for Fort Nelson (2018 - $4,370 million, excluding the rate base of approximately $11 million for Fort Nelson) and an increase to the delivery rate of 1.1 per cent effective January 1, 2019. Also in the first quarter of 2019, the BCUC issued its decision approving an increase to FEI's midstream rates to reflect both the recovery of increased costs of procuring additional gas on the open market to replace the gas that was not received through the Westcoast natural gas transmission pipeline during 2018, as well as the forecasted increase in midstream costs over the next twelve months. Combined with the 1.1 per cent delivery rate increase, the pass through of these costs to customers resulted in an approximate 9 per cent increase to residential rates on January 1, 2019.

Multi-Year Rate Plan for 2020 to 2024

In March 2019, FEI filed its MRP Application, an application with the BCUC requesting approval of a Multi-year Rate Plan for the years 2020 to 2024. The MRP Application proposes a rate-setting framework that includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation, a similar approach to growth capital, and a forecast approach to sustainment capital, a 50:50 sharing between customers and the Corporation of variances from the allowed Return on Equity, targeted incentives for the Corporation related to growth, emissions reductions and customer engagement, and an innovation fund recognizing the need to accelerate investment in clean energy innovation. FEI is also seeking approval of updated depreciation rates and a number of service quality indicators designed to ensure the Corporation maintains service levels. The regulatory process to review this application will continue through 2019, with a decision expected in early 2020.

CONSOLIDATED RESULTS OF OPERATIONS

Quarters Ended March 31	**2019**	2018	Variance
Gas sales (petajoules)	**83**	80	3
($ millions)			
Revenue	**485**	428	57
Cost of natural gas	**181**	134	47
Operation and maintenance	**66**	58	8
Property and other taxes	**17**	17	-
Depreciation and amortization	**60**	56	4
Total expenses	**324**	265	59
Operating income	**161**	163	(2)
Add: Other income	**3**	16	(13)
Less: Finance charges	**35**	48	(13)
Earnings before income taxes	**129**	131	(2)
Income tax expense	**30**	30	-
Net earnings	**99**	101	(2)

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the three months ended March 31, 2019 as compared to March 31, 2018:

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings	**(2)**	Net earnings for the quarter ended March 31, 2019 were $99 million compared to $101 million for the same period in 2018 primarily due to: • lower income tax benefit as a result of the Corporation having a tax loss utilization plan ("TLUP") in place in 2018, effective March 1, 2018, compared to no TLUP implemented during the first quarter of 2019, and • lower operation and maintenance expense savings for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year, partially offset by • higher investment in regulated assets. Both 2019 and 2018 net earnings are based on allowed return on equity of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent.
Revenue	**57**	Total revenue includes revenue from contracts with customers, which is comprised of tariff revenue, fees charged for tariff-based customer connections, and revenue from agreements with customers to provide transportation of natural gas over utility owned infrastructure.

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
		Also included in total revenue is alternative revenue, which is comprised of the regulated Earnings Sharing Mechanism, Revenue Stabilization Adjustment Mechanism ("RSAM"), and flow-through variances related to industrial and other customer revenue. Lastly, total revenue includes other revenue, which is primarily comprised of regulatory deferral adjustments that capture variances from regulated forecast items, excluding formulaic operation and maintenance costs. If such regulatory deferral adjustments recognized in the current period are owed to, or recoverable from, customers in future rates, they are recognized as either other expense or other revenue, respectively. The increase in total revenue was primarily due to: • a higher cost of natural gas recovered from customers, as approved by the BCUC, • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability which was recognized in revenue, • an increase in revenue approved for rate-setting purposes resulting from higher investment in regulated assets, and • a decrease in flow-through deferral amounts to be refunded to customers in future rates. Gas sales volumes were higher primarily due to higher average consumption by residential and commercial customers as a result of colder weather. The variance between revenue associated with actual average consumption and revenue forecasted for rate-setting purposes is captured either in the RSAM deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenue. The higher consumption resulted in increased revenue from contracts with customers, but was offset by an equal alternative revenue amount resulting in no impact on total revenue.
Cost of natural gas	**47**	The cost of natural gas includes commodity, storage and transport, as well as the storage and transport variances captured in the MCRA deferral account, all of which are passed through to customers with no impact to the margin on gas sales or net earnings. Changes in consumption levels of customers and changes in the commodity cost of natural gas, compared to those approved by the BCUC, do not materially impact earnings as a result of regulatory deferral accounts. The increase in the cost of natural gas was primarily due to: • a higher storage and transport cost, approved by the BCUC, of $1.485 per gigajoule for the quarter ended March 31, 2019, as compared to $1.064 per gigajoule for the same quarter in 2018, • a lower amount of MCRA gas storage and transport cost regulatory liability refunded to customers, which decreases the cost of natural gas, during the quarter, and • higher gas sales consumption compared to the same period in 2018.
Operation and maintenance	**8**	The increase in operation and maintenance expense was primarily due to the timing of incurring these costs in the first quarter of 2019 as compared to the same period in 2018, higher labour and contracting costs, and higher electricity costs to operate the Tilbury LNG facility.
Depreciation and amortization	**4**	The increase was primarily due to a higher depreciable asset base compared to the prior year, including depreciation on the Tilbury Phase 1A Expansion Project and the Vancouver portion of the LMIPSU, both beginning January 1, 2019, partially offset by lower amortization of regulatory assets.
Other income	**(13)**	Other income primarily consists of dividend income from TLUP structures, the equity component of allowance for funds used during construction ("AFUDC"), and the non-service cost component of pension and other post-employment benefits which was recognized as a credit to other income. The decrease in other income was primarily due to lower dividend income due to FEI having a TLUP in place in 2018 compared to no TLUP implemented in the first quarter of 2019, partially offset by an increase in the non-service cost component of pension and other post-employment benefits. As part of the 2018 TLUP, the Corporation received dividend income from FHI relating to a $2,500 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

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
		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.
Finance charges	**(13)**	The decrease in finance charges was primarily due to FEI having a TLUP in place in 2018 compared to no TLUP implemented in the first quarter of 2019, partially offset by higher interest from a higher level of debt used to finance the increased investment in regulated assets, and the issuance of long-term debentures in December 2018, which were used to repay credit facilities carrying lower interest rates.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended June 30, 2017 through March 31, 2019. The information has been obtained from the Corporation's Unaudited Condensed Consolidated Interim Financial Statements. 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 Earnings (Loss)[1]**
($ millions)		
March 31, 2019	485	99
December 31, 2018	371	80
September 30, 2018	161	(10)
June 30, 2018	227	18
March 31, 2018	428	101
December 31, 2017	366	73
September 30, 2017	156	(4)
June 30, 2017	228	17

[1] Net earnings (loss) attributable to controlling interest.

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 net earnings are not indicative of net earnings on an annual basis.

March 2019/2018 – Net earnings were lower primarily due to lower income tax benefit as a result of the Corporation having a TLUP in place in 2018, effective March 1, 2019, compared to no TLUP implemented in the first quarter of 2019 and lower operation and maintenance expense savings for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year, partially offset by higher investment in regulated assets.

December 2018/2017 – Net earnings were higher primarily due to higher investment in regulated assets and higher operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year.

September 2018/2017 – Net loss was higher primarily due to lower operating and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year and a non-recurring benefits refund received during the third quarter of 2017 for which there was no comparable amount received in the same period of 2018, and lower interest savings, partially offset by higher investment in regulated assets.

June 2018/2017 – Net earnings were higher primarily due to higher investment in regulated assets.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between March 31, 2019 and December 31, 2018:

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Accounts receivable	**103**	The increase was primarily due to higher customer trade receivables as a result of colder weather in the first quarter of 2019, as compared to the fourth quarter of 2018, and $40 million cash collateral paid due to an increased fair market value of natural gas derivatives.
Inventories	**(18)**	The decrease was primarily due to the drawdown of natural gas in storage during the winter months, partially offset by an increase in the weighted average cost of quarterly natural gas storage.
Regulatory assets (current and long-term)	**32**	The increase was primarily due to: • higher MCRA regulatory asset, which moved from a regulatory liability position at December 31, 2018 to a regulatory asset position at March 31, 2019 primarily due to higher natural gas midstream costs and payments made by FEI during the first quarter of 2019 to secure long-term natural gas pipeline capacity, • higher regulated deferred income tax liability, the offset of which was recorded as a regulatory asset, partially offset by • the change in the fair market value of natural gas derivatives, which moved from an unrealized loss of $9 million recorded as a current regulatory asset at December 31, 2018 to an unrealized gain of $8 million recorded as a current regulatory liability at March 31, 2019.
Property, plant and equipment, net	**21**	The increase was primarily due to capital expenditures of $67 million incurred during the first quarter of 2019, which included sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures", $2 million in changes in working capital and $1 million in AFUDC, partially offset by: • depreciation expense, excluding net salvage provision, of $43 million, • costs of removal of $4 million incurred, the offset of which has been recognized in regulatory liabilities, and • contributions in aid of construction of $2 million.
Credit facility	**110**	The increase was primarily due to higher borrowings as a result of lower cash from operating activities, as well as to finance the debt portion of FEI's 2019 capital expenditure program.
Accounts payable and other current liabilities	**(39)**	The decrease was primarily due to: • lower gas cost payables as a result of lower cost of gas purchased, • seasonal decrease in credit balances related to customer payment plan arrangements, and • the change in the fair market value of natural gas derivatives, partially offset by • higher property tax and carbon tax payable.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Quarters Ended March 31	2019	2018	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**20**	180	(160)
Investing activities	**(77)**	(84)	7
Financing activities	**64**	(93)	157
Net change in cash	**7**	3	4

Operating Activities

Cash provided by operating activities was $160 million lower compared to 2018 primarily due to:

- changes in working capital of $133 million primarily related to higher customer receivables as a result of colder weather in the first quarter of 2019 and $40 million cash collateral paid due to an increased fair market value of natural gas derivatives, and
- changes in regulatory assets and liabilities arising from the variance between midstream and commodity costs incurred and collected in customer rates, which were recognized in the MCRA and CCRA deferral accounts, respectively.

Investing Activities

Cash used for investing activities was $7 million lower in 2019 compared to the same period in 2018. This was primarily due to lower capital expenditures, partially offset by changes in other assets and liabilities due to higher investment in Demand Side Management expenditures and Greenhouse Gas Reductions Regulation programs.

Financing Activities

Cash flows provided by financing activities were $64 million compared to 2018 when cash used for financing activities was $93 million. The change in financing cash flows was primarily driven by lower cash flows from operating activities which required the Corporation to borrow $110 million from its credit facility in 2019, compared to net credit facility repayments of $44 million in 2018, and a deposit received for development expenditures during the first quarter of 2019 for which there was no equivalent for the same period in 2019, partially offset by higher common share dividends paid.

During the quarter ended March 31, 2019, FEI paid common share dividends of $50 million (2018 - $47 million) to its parent company, FHI.

Contractual Obligations

The following table sets forth a material change in the Corporation's estimated contractual obligations from those reported in the Corporation's 2018 annual MD&A:

As at March 31, 2019	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)							
Gas purchase obligations (a)	**338**	**-**	**8**	**8**	**8**	**8**	**306**

(a) During the first quarter of 2019, FEI entered into two, separate agreements to purchase additional Winter Firm Service pipeline capacity on the Westcoast Pipeline for a 42-year term, beginning in the fourth quarter of 2020. Both agreements were accepted by the BCUC in February 2019.

Credit Ratings

There have been no changes to the Corporation's credit ratings from those reported in the Corporation's 2018 annual MD&A, which are summarized in the table below:

Rating Agency	Credit Rating	Type of Rating	Outlook
DBRS	A	Unsecured Debentures	Stable
Moody's	A3	Unsecured Debentures	Stable

Projected Capital Expenditures

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenditures that will be incurred in the ongoing operation of its business. The initial approval from the BCUC to proceed with capital projects can occur through a number of processes, including revenue requirement applications and CPCNs. Once the projects are approved, the regulatory process allows for capital project costs to be reviewed by the BCUC subsequent to the capital project being completed and in service to confirm that all costs are recoverable in customer rates.

The 2019 projected capital expenditures are approximately $510 million, inclusive of AFUDC and excluding customer contributions in aid of construction, and are necessary to provide service, public and employee safety, and reliability of supply of natural gas to the Corporation's customer base. In addition to the rate base amounts approved in annual regulatory decisions, multi-year projects under construction earn a regulated return.

Included in the 2019 projected capital expenditures are the current year costs of construction for the IGU project and the LMIPSU project.

LMIPSU Project

In December 2014, the Corporation filed a CPCN application to replace certain sections of intermediate pressure gas line segments within the Greater Vancouver area. In October 2015, the BCUC approved the CPCN substantially as filed, which included an estimate of the project costs of approximately $250 million. In the course of its project development activities, FEI conducted further detailed engineering work and evaluated construction bids and other costs which resulted in a revised cost estimate of the project of approximately $500 million. This estimate was provided to the BCUC during the first quarter of 2018 as a compliance filing for their information. The Vancouver section of the project was completed and gasified in December 2018. Construction of the remaining portion of the project has resumed in the first quarter of 2019. After the project is complete and in service, the final project costs remain subject to the BCUC's review process.

Other Major Capital Projects

Beyond 2019, the Corporation has received BCUC or OIC approval for further major capital projects discussed below.

LNG Infrastructure

The Corporation continues to pursue additional LNG infrastructure investment opportunities in BC, including a gas line expansion to the proposed Woodfibre LNG site near Squamish, BC, and a further expansion of Tilbury. The 2013 OIC as amended, granted FEI exemptions from the requirement to seek BCUC CPCN approvals for the pipeline expansion to the Woodfibre LNG site and certain further expansions at the Tilbury site, subject to certain conditions.

The anticipated capital expenditures, net of the forecasted customer contributions, of FEI's potential gas line expansion are $350 million, conditional on Woodfibre LNG proceeding with its LNG export facility. The current estimate of FEI's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of the customer contributions. During the fourth quarter of 2018, FEI and Woodfibre LNG entered into a pre-execution work agreement that establishes the funding requirements to be provided by Woodfibre LNG for FEI to incur ongoing project feasibility and development costs. During the first quarter of 2019, FEI incurred approximately $4 million in development expenditures for the project and received $5 million of cash deposits.

FEI's proposed gas line expansion remains contingent on Woodfibre LNG making a final decision as to whether to proceed with construction of its LNG export facility. At this time, should the project proceed, it is not expected to be in service before 2023.

Credit Facility and Debentures

Credit Facility

As at March 31, 2019, the Corporation had a $700 million syndicated credit facility available which matures in August 2023.

The following summary outlines the Corporation's credit facility:

($ millions)	March 31, 2019	December 31, 2018
Credit facility	**700**	700
Draws on credit facility	**(309)**	(199)
Letters of credit outstanding	**(48)**	(48)
Credit facility available	**343**	453

Debentures

On October 20, 2017, the Corporation filed a short form base shelf prospectus to establish a Medium Term Note Debenture ("MTN Debentures") Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may, from time to time during the 25-month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $650 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

As at March 31, 2019, $275 million remains available under the MTN Debenture Program.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FBC and ACGS, in financing transactions and to provide or receive services and materials. The following transactions were measured at the exchange amounts unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the three months ended March 31 were as follows:

($ millions)	2019	2018
Operation and maintenance expense charged to FBC (a)	**1**	1
Other income received from FHI (b)	**-**	15
Total related party recoveries	**1**	16

(a) The Corporation charged FBC for natural gas sales, office rent, management services, and other labour.

(b) As part of a TLUP in the first quarter of 2018, the Corporation received dividend income from FHI relating to a $2,500 million investment in preferred shares. No TLUP investment was made in the first quarter of 2019.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the three months ended March 31 were as follows:

($ millions)	2019	2018
Operation and maintenance expense charged by FBC (a)	**2**	2
Operation and maintenance expense charged by FHI (b)	**3**	3
Finance charges paid to FHI (c)	**-**	15
Gas storage and purchases charged by ACGS (d)	**6**	7
Total related party costs	**11**	27

(a) FBC charged the Corporation for electricity purchases, management services and other labour.

(b) FHI charged the Corporation for management services, labour and materials, and governance costs.

(c) As part of a TLUP in the first quarter of 2018, the Corporation paid FHI interest on $2,500 million of intercompany subordinated debt. No TLUP subordinated debt existed in the first quarter of 2019.

(d) ACGS charged the Corporation for the lease of natural gas storage capacity and natural gas purchases.

Balance Sheet Amounts

The amounts due from related parties, included in accounts receivable on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, are as follows:

	March 31, 2019		December 31, 2018	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**-**	-	(2)
FBC	**-**	**(1)**	-	-
ACGS	**-**	**(2)**	-	(2)
Total due from (due to) related parties	**-**	**(3)**	-	(4)

FINANCIAL INSTRUMENTS

Financial Instruments Measured at Fair Value on a Recurring Basis

The following table presents the Corporation's assets and liabilities accounted for at fair value on a recurring basis, all of which are Level 2 of the fair value hierarchy:

($ millions)	**March 31, 2019**	December 31, 2018
Assets		
Current		
Natural gas contracts subject to regulatory deferral [1]	**9**	5
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**6**	9
Total assets	**15**	14
Liabilities		
Current		
Natural gas contracts subject to regulatory deferral [1]	**(7)**	(22)
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**-**	(1)
Total liabilities	**(7)**	(23)
Total assets (liabilities), net	**8**	(9)

[1] Derivative contracts that are "in the money" are included in accounts receivable or other assets, and "out of the money" are included in accounts payable and other current liabilities or other liabilities.

The Corporation has elected gross presentation for its derivative contracts under master netting agreements, which applies only to its natural gas derivatives. The table below presents the potential offset of counterparty netting and cash collateral:

		Gross Amount Not Offset in the Balance Sheet		
March 31, 2019	**Gross Amount Recognized in the Balance Sheet**	**Counterparty Netting of Natural Gas Contracts [1]**	**Cash Collateral Posted**	**Net Amount**
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	**9**	**(1)**	**56**	**64**
Other assets	**6**	**-**	**-**	**6**
Accounts payable and other current liabilities	**(7)**	**1**	**-**	**(6)**

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

December 31, 2018	Gross Amount Recognized in the Balance Sheet	Gross Amount Not Offset in the Balance Sheet: Counterparty Netting of Natural Gas Contracts [1]	Gross Amount Not Offset in the Balance Sheet: Cash Collateral Posted	Net Amount
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	5	(4)	16	17
Other assets	9	(1)	-	8
Accounts payable and other current liabilities	(22)	4	-	(18)
Other liabilities	(1)	1	-	-

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

Derivative Instruments

Natural gas contracts held by FEI are subject to regulatory recovery through rates. As at March 31, 2019, these natural gas contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

($ millions)	**March 31, 2019**	December 31, 2018
Unrealized net gain (loss) recorded to current regulatory liabilities (assets)	**8**	(9)

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's Consolidated Statements of Cash Flows.

Financial Instruments Not Measured At Fair Value

The following table includes the carrying value and estimated fair value of the Corporation's long-term debt:

		March 31, 2019		December 31, 2018	
($ millions)	**Fair Value Hierarchy**	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt [1]	Level 2	**2,595**	**3,202**	2,595	2,994

[1] Carrying value excludes unamortized debt issuance costs.

NEW ACCOUNTING POLICIES

Standard	Effective Date	Description	Effect on FEI
Leases	January 1, 2019	ASU No. 2016-02, *Leases* (ASC Topic 842), requires lessees to recognize a right-of-use asset and lease liability for all leases with a lease term greater than 12 months, along with additional quantitative and qualitative disclosures. When a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a right-of-use asset and lease liability are recognized. At inception, the right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.	FEI applied the transition provisions as of the adoption date and did not retrospectively adjust prior periods. FEI elected a package of implementation options, referred to as practical expedients, that allowed it to not reassess: (i) whether existing contracts, including land easements, are or contain a lease; (ii) the lease classification of existing leases; or (iii) the initial direct costs for existing leases. For operating leases, the future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which FEI accounts for as a single lease component. The Corporation has not elected to combine lease and non-lease components for the finance leases. Also, the Corporation utilized the hindsight practical expedient to determine the lease term. Upon adoption, the Corporation did not identify or record an adjustment to the opening balance of

Standard	Effective Date	Description	Effect on FEI
		Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense straight-line over the lease term.	retained earnings, and there was no impact on net earnings or cash flows. As at March 31, 2019, the Corporation recognized $7 million of right-of-use assets and lease liabilities related to office facilities.

FUTURE ACCOUNTING PRONOUNCEMENTS

FEI considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The ASUs issued by FASB, but not yet adopted by FEI were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on the Consolidated Financial Statements.

OTHER DEVELOPMENTS

Collective Agreements

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expired on March 31, 2019 and bargaining between FEI and IBEW continues. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

There are two collective agreements between the Corporation and Local 378 of the Canadian Office and Professional Employees Union now referred to as MoveUP. The first collective agreement representing customer service employees expires on March 31, 2022. The second collective agreement representing employees in specified occupations in the areas of administration and operations support expires on June 30, 2023.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 328,928,792 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information about FEI, including its AIF, can be accessed at www.fortisbc.com or www.sedar.com. The information contained on, or accessible through, either of these websites is not incorporated by reference into this document.

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