FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS
For the Quarter Ended March 31, 2023

May 2, 2023

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 2023 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 quarter ended March 31, 2023, 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, 2022, with 2021 comparatives, prepared in accordance with US GAAP.

In this MD&A, FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., FAES refers to FortisBC Alternative Energy Services 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 expectation that the British Columbia Utilities Commission (the "BCUC") will issue a decision in its current General Cost of Capital Proceeding (the "GCOC Proceeding") by mid-2023; the Corporation's expectation that the size of its existing operating credit facility is adequate to accommodate any changes to the approved capital structure resulting from the outcome of the GCOC Proceeding; the Corporation's expected level of capital expenditures, including forecasted project costs, and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; and the Corporation's estimated contractual obligations.

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 (including absence of administrative monetary penalties); the competitiveness of natural gas pricing when compared with alternate sources of energy; continued demand for natural gas; absence of climate change impacts; absence of adverse weather conditions and natural disasters; absence of environmental damage and health and safety issues; absence of asset breakdown; the availability of natural gas supply; the ability to maintain and obtain applicable permits; the Indigenous engagement process will not delay or otherwise impact the Corporation's ability to obtain government or regulatory approvals; the adequacy of the Corporation's existing insurance arrangements; the ability to arrange sufficient and cost effective financing; no material adverse rating actions by credit rating agencies; continued energy demand; continued population growth and new housing starts; the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations; the ability of the Corporation to attract and retain a skilled workforce; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; absence of information technology infrastructure failure; absence of cybersecurity failure; absence of pandemic and public health crises impacts; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2027 or earlier; and the absence of legal, administrative and other proceedings.

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); natural gas competitiveness risk; commodity price risk; climate change risk; weather and natural disasters risk; environment, health and safety matters risk; natural gas supply risk; asset breakdown, operation, maintenance and expansion risk; permits risk; risks related to Indigenous rights and engagement; underinsured and uninsured losses; capital resources and liquidity risk; interest rates risk; impact of changes in economic conditions risk; counterparty credit risk; human resources risk; labour relations risk; employee future benefits risk; information technology infrastructure risk; cybersecurity risk; pandemic and public health crises risk; continued reporting in accordance with US GAAP risk; legal, administrative and other proceedings risk; 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 "Business Risk Management" section of the Corporation's MD&A and AIF for the year ended December 31, 2022.

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 1,078,800 residential, commercial, industrial, and transportation customers through approximately 51,200 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers and obtains natural gas and renewable 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 regulated by the BCUC. Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as rates, construction plans, and financing.

The Corporation is an indirect, wholly owned subsidiary of Fortis, a leader in the North American regulated electric and natural gas utility industry. Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

REGULATION

Decision on Multi-Year Rate Plan ("MRP") for 2020 to 2024

In June 2020, the BCUC issued its decision on FEI's MRP application for the years 2020 to 2024 ("MRP Decision"). The approved MRP includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustainment capital, an innovation fund recognizing the need to accelerate investment in clean energy innovation, a number of service quality indicators designed to ensure the Corporation maintains service levels, and a 50/50 sharing between customers and the Corporation of variances from the allowed Return on Equity ("ROE").

Variances from the allowed ROE subject to sharing include certain components of other revenue and operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, while variances associated with revenues and other expenses, including those that are not controllable or associated with clean growth expenditures, are subject to flow-through treatment and refunded to or recovered from customers.

In December 2022, the BCUC approved a delivery rate increase of 7.69 per cent over 2022 rates, on an interim basis, effective January 1, 2023, pending the outcomes of Stage 1 of the BCUC's GCOC Proceeding. The interim rate increase includes a 2023 forecast average rate base of $5,943 million, which is inclusive of the Demand Side Management ("DSM") Expenditures Plan that was accepted by the BCUC in March 2023.

In October 2022, FEI received approval to implement common delivery rates and cost of gas rates with its customers located in the Fort Nelson Service Area, with the exception of storage and transport rates for the Fort Nelson Service Area customers which are to be set at 5 per cent of the storage and transport costs for all other FEI customers. The delivery rate impact for residential customers in the Fort Nelson Service Area is to be phased in over five years starting January 1, 2023.

Allowed Return on Equity and Capital Structure

In January 2021, the BCUC announced that a GCOC Proceeding was being initiated, including a review of the deemed common equity component of total capital structure and the allowed ROE on common equity for regulated utilities in BC. The BCUC has determined the GCOC Proceeding will move forward in two stages. The first stage will address the allowed ROE and deemed equity component of capital structure for FEI and FBC and the effective date for any change, whether re-establishment of a formulaic ROE automatic adjustment mechanism is warranted and if so, what it would look like and when it would take effect, and the criteria or other triggers for a future cost of capital proceeding. Other utilities will be reviewed in Stage 2. The BCUC has also determined it will address deferral account financing costs after the completion of both Stages 1 and 2. During 2022, as part of Stage 1 of the GCOC Proceeding, FEI and FBC submitted evidence in support of their respective cost of capital, after which a regulatory review process took place which included various forms of evidence, an oral hearing, and a final argument, which was filed in December 2022. The final stages of argument were completed in February 2023. A decision from the BCUC is expected by mid-2023.

Customer Rates and Deferral Mechanisms

Customer rates include both the delivery charge and the cost of natural gas, consisting of the commodity cost and the storage and transport cost. The Corporation's customer rates are based on estimates and forecasts. In order to manage the variances from forecast associated with some of these estimates and to manage volatility in rates, a number of regulatory deferral accounts are in place.

Variances from regulated forecasts used to set rates for natural gas revenue and cost of natural gas 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 for the quarters ended March 31, 2023 and 2022.

FEI reviews the costs of natural gas with the BCUC either quarterly or annually to ensure the rates passed on to customers are fair and reflect actual costs. FEI received approval to increase the commodity rate effective January 1, 2022 and July 1, 2022. In December 2022, FEI received approval to decrease the commodity rate effective January 1, 2023. In March 2023, FEI received approval to decrease the commodity rate effective April 1, 2023. FEI also received approval to increase the storage and transport rate effective January 1, 2022 and January 1, 2023.

As part of the MRP for the years 2020 to 2024, the BCUC has approved certain regulatory deferral mechanisms, including those that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation. These deferral mechanisms capture variances from regulated forecasts and flow them through customer rates in subsequent years. Variances from the allowed ROE, including most components of operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, are shared.

CONSOLIDATED RESULTS OF OPERATIONS

Quarter ended March 31	**2023**	2022	Variance
Gas sales *(petajoules)*	**79**	81	(2)
($ millions)			
Revenue	**750**	694	56
Cost of natural gas	**375**	354	21
Operation and maintenance	**76**	65	11
Property and other taxes	**20**	18	2
Depreciation and amortization	**78**	76	2
Total expenses	**549**	513	36
Operating income	**201**	181	20
Add: Other income	**7**	4	3
Less: Finance charges	**41**	36	5
Earnings before income taxes	**167**	149	18
Income tax expense	**45**	31	14
Net earnings	**122**	118	4

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the quarter ended March 31, 2023 as compared to March 31, 2022:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings	**4**	Net earnings for the quarter ended March 31, 2023 were $122 million compared to $118 million for the same period in 2022. The increase was primarily due to a higher investment in regulated assets and an increase in gas mitigation incentive revenue, which is retained by the utility, partially offset by higher operating costs, the variances of which are retained by the utility. Both 2023 and 2022 net earnings are based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent. The Corporation's capital structure could change depending on the outcome of the GCOC Proceeding discussed in the "Regulation" section of this MD&A.
Revenue	**56**	The increase in revenue was primarily due to: • a higher cost of natural gas recovered from customers, as approved by the BCUC, • an increase in revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, • an increase in revenue associated with regulatory deferrals, and • an increase in gas mitigation incentive revenues, partially offset by • an increase in the refund of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory liability, compared to the prior year. Gas sales volumes were lower than the same quarter in the previous year, primarily due to lower consumption by residential and transportation customers. The variance between revenue associated with actual consumption and revenue forecasted for rate-setting purposes is captured either in the Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenue and other revenue, resulting in no impact on total revenue.
Cost of natural gas	**21**	The increase was primarily due to: • a higher commodity cost, approved by the BCUC, of $5.159 per gigajoule ("GJ") for the first quarter of 2023, as compared to $4.503 per GJ for the first quarter of 2022, and • a higher storage and transport cost, approved by the BCUC, of $1.543 per GJ for the first quarter of 2023, as compared to $1.505 per GJ for the first quarter of 2022, partially offset by • a decrease in total consumption of gas by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity, and • an increase in the refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year. Customers that purchase bundled services from FEI require the Corporation to not only provide delivery service, but also provide the gas commodity, which entails managing the commodity portfolio, including the costs to procure, store and transport the gas. During the first quarter of 2023, volumes provided to customers under bundled services and customers that received only delivery service were both lower compared to the same quarter in 2022. Although total sales volumes were lower, only the lower volumes provided to customers under bundled services drove a lower cost of natural gas in the first quarter of 2023.
Operation and maintenance	**11**	The increase was primarily due to higher costs, the variances of which are retained by the utility, as well as inflationary increases contributing to an overall increase in costs that are flowed through or shared with customers, as well as a higher service cost component of pension and other post-employment benefits expense ("OPEB").

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Other income	**3**	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 OPEB, which is recognized as a credit to other income. The increase was primarily due to an increase in the non-service cost component of pension and OPEB.
Finance charges	**5**	The increase was primarily due to an increase in total borrowings used to finance the debt component of FEI's capital expenditure program, a higher borrowing rate on credit facilities compared to the prior year, and higher interest on long-term debt driven by the issuance of Medium Term Note Debentures ("MTN Debentures") during the fourth quarter of 2022, which was used to repay credit facilities carrying lower borrowing rates.
Income tax expense	**14**	The increase was primarily due to lower deductible temporary differences associated with property, plant and equipment, higher earnings before income tax, and higher taxable temporary differences associated with amortization of regulatory deferrals being recovered from customers in rates.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth quarterly information for each of the eight quarters ended June 30, 2021 through March 31, 2023. 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, 2023	750	122
December 31, 2022	724	91
September 30, 2022	269	(7)
June 30, 2022	396	25
March 31, 2022	694	118
December 31, 2021	590	78
September 30, 2021	222	(20)
June 30, 2021	316	14

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

A summary of the past eight quarters reflects the seasonality associated with the Corporation's business. Due to the seasonal nature of natural gas consumption patterns based on weather and its impact on revenues, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters of the fiscal year and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. Certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year. As a result of the seasonality, interim net earnings are not indicative of net earnings on an annual basis.

March 2023/2022 – Net earnings were higher due to a higher investment in regulated assets and an increase in gas mitigation incentive revenue, which is retained by the utility, partially offset by higher operating costs, the variances of which are retained by the utility.

December 2022/2021 – Net earnings were higher due to a $8 million higher income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2022, where no similar TLUP was implemented in 2021, a higher investment in regulated assets, higher favourable regulated variances partially attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, and an increase in gas mitigation incentive revenue, which is retained by the utility, partially offset by higher costs, the variances of which are retained by the utility.

September 2022/2021 – Net loss was lower due to a $10 million higher income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2022, where no similar TLUP was implemented in 2021, a higher investment in regulated assets, an increase in gas mitigation incentive revenue, which is retained by the utility, partially offset by higher costs, the variances of which are retained by the utility.

June 2022/2021 – Net earnings were higher due to a $9 million higher income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2022, where no similar TLUP was implemented in 2021; and higher investment in regulated assets.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between March 31, 2023 and December 31, 2022:

Balance Sheet Account	**Increase (Decrease)** *($ millions)*	**Explanation**
Cash	**131**	The increase in cash was primarily due to changes in regulatory assets and liabilities, which were driven by changes in the MCRA deferral account due to higher mitigation activities and amounts collected in customer rates exceeding the midstream costs incurred, as well as changes in the Commodity Cost Reconciliation Account ("CCRA"), and from the receipt of a cash deposit relating to development expenditures to be incurred for the Eagle Mountain Gas Pipeline ("EGP") project. Cash on hand at March 31 has primarily been invested in short-term deposits.
Accounts receivable and other current assets, net	**(148)**	The decrease was primarily due to: • lower tariff-based trade receivables, as a result of seasonality of revenues, partially offset by increased customer rates, • lower gas cost mitigation receivables, and • a change in the fair value of natural gas derivatives.
Inventories	**(71)**	The decrease was primarily due to the seasonal drawdown of natural gas in storage during the winter months and a lower weighted average cost of gas in storage.
Property, plant and equipment, net	**34**	The increase was primarily due to capital expenditures of $111 million incurred during the quarter, and $2 million in equity AFUDC, less: • depreciation expense, excluding net salvage provision, of $50 million, • changes in accrued capital expenditures of $23 million, • contributions in aid of construction ("CIAC") of $2 million received, and • costs of removal of $4 million incurred, which is included as part of the net salvage provision in regulatory liabilities.
Credit facilities	**(178)**	The decrease was primarily a result of net repayments from seasonal operating cash flows during the first quarter.
Accounts payable and other current liabilities	**(41)**	The decrease was primarily due to: • lower gas cost payables, as a result of a lower cost of gas purchased, • lower accrued capital expenditures, and • a seasonal decrease in credit balances related to customer payment plan arrangements, partially offset by • a change in the fair value of natural gas derivatives, • higher cash deposits held relating to development expenditures incurred for the EGP project, • higher property tax and carbon tax payable, and • higher income tax payable.
Regulatory liabilities (current and long-term)	**77**	The increase was primarily due to: • a higher MCRA regulatory liability due to higher mitigation activities and amounts collected in customer rates exceeding the midstream costs incurred, and • an increase in the net salvage provision, partially offset by • a decrease in the Emissions Regulations deferral account, which captured the sale of carbon credits in 2022 generated under the BC Low Carbon Fuel Standard, and is being refunded to customers through delivery rates in 2023.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Deferred income tax	**(31)**	The decrease was primarily due to higher taxable temporary differences associated with certain regulatory deferral asset and liability accounts, and higher taxable temporary differences associated with taxable deposits received during the quarter, partially offset by higher deductible temporary differences associated with property, plant and equipment.
Other liabilities (long-term)	**(39)**	The decrease was primarily due to a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**100**	The increase was due to a $100 million FEI equity injection from the Corporation's parent company, FHI, during the quarter, the proceeds of which were used to support the equity component of FEI's capital expenditure program.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements and Liquidity

In the normal course of operations, the Corporation's cash flow requirements fluctuate seasonally based primarily on natural gas consumption. The Corporation maintains a committed credit facility that adequately meets any working capital deficiencies not funded through cash flow from operations, and for financing the debt component of the Corporation's capital expenditure program.

It is expected that operating expenses, interest costs, and other working capital will generally be paid out of operating cash flows, with varying levels of residual cash available for capital expenditures and/or dividend payments. Cash flow is also required to fund capital expenditure programs; pre-development capital costs; regulated deferral accounts, and those regulatory mechanisms that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation; and investments in DSM and natural gas for transportation programs under the Greenhouse Gas Reductions Regulations. Funding requirements are expected to be financed from a combination of cash flow from operations, borrowings under the credit facility, equity injections from FHI, and long-term debenture issuances in accordance with the deemed regulatory capital structure approved by the BCUC of 38.5 per cent equity and 61.5 per cent debt. The approved capital structure could change depending on the outcome of the GCOC Proceeding discussed in the "Regulation" section of this MD&A, however the size of the Corporation's existing operating credit facility is considered adequate to accommodate any changes to the approved capital structure.

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 working capital deficiencies and payment of dividends. The Corporation may have to rely upon the proceeds of new debenture issuances to meet its principal debt obligations when they become due.

Summary of Consolidated Cash Flows

Quarter ended March 31	**2023**	2022	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**393**	258	135
Investing activities	**(124)**	(137)	13
Financing activities	**(138)**	(106)	(32)
Net change in cash	**131**	15	116

Operating Activities

Cash from operating activities was $135 million higher compared to the same period in 2022, primarily due to changes in regulatory assets and liabilities, which were driven by changes in the MCRA deferral account due to higher mitigation activities and amounts collected in customer rates exceeding the midstream costs incurred as well as changes in the CCRA. In addition, higher cash was provided by working capital changes, which were driven by changes in accounts receivable and inventory, partially offset by changes in accounts payable which are net of cash provided by changes in the deposit held for the EGP project.

Investing Activities

Cash used in investing activities was $13 million lower compared to the same period in 2022 primarily due to lower capital expenditures, partially offset by lower customer CIAC received.

Financing Activities

Cash used in financing activities was $32 million higher compared to the same period in 2022, primarily driven by proceeds from a $100 million issuance of common shares during the quarter as compared to proceeds from a $150 million issuance of common shares in the same period in 2022, partially offset by less net repayments on existing credit facilities compared to the same period in 2022.

During the quarter ended March 31, 2023, FEI paid common share dividends of $60 million (2022 - $57 million) to its parent company, FHI.

Contractual Obligations

The Corporation's contractual obligations have not materially changed from those disclosed in the MD&A for the year ended December 31, 2022.

Credit Ratings

There have been no changes to the Corporation's credit ratings from those disclosed in the MD&A for the year ended December 31, 2022, which are summarized in the table below:

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

In January 2023, DBRS Morningstar issued an updated credit rating report, confirming the Corporation's debenture rating and outlook.

Credit Facilities and Debentures

Credit Facilities

As at March 31, 2023, the Corporation had a $700 million syndicated operating credit facility in place, which matures in July 2027 and incorporates a Sustainability Linked Loan component, with performance targets considering avoided emissions from renewable gas and capital project opportunities with Indigenous participation. The Corporation also had a $55 million uncommitted letter of credit facility in place at March 31, 2023, which matures in March 2024.

The following summary outlines the Corporation's credit facilities:

($ millions)	**March 31, 2023**	December 31, 2022
Operating credit facility	**700**	700
Letter of credit facility	**55**	55
Draws on operating credit facility	**(25)**	(203)
Letters of credit outstanding	**(40)**	(54)
Credit facilities available	**690**	498

Debentures

On November 16, 2022, the Corporation filed a short form base shelf prospectus to establish a 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 $800 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

As at March 31, 2023, $650 million remains available under the MTN Debentures Program.

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 Certificate of Public Convenience and Necessity ("CPCN") applications. 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 2023 projected capital expenditures are approximately $536 million, inclusive of AFUDC and excluding customer CIAC, 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. The 2022 annual capital expenditures were $589 million, inclusive of AFUDC and excluding CIAC.

Included in these 2023 projected capital expenditures are more significant projects, including Inland Gas Upgrade, Pattullo Gas Line Replacement, Okanagan Capacity Upgrade ("OCU"), Tilbury LNG Storage Expansion ("TLSE"), Advanced Metering Infrastructure Project, Transmission Integrity Management Capabilities, Tilbury Phase 1B Expansion Project, and Other Capital Projects, which were described in the MD&A for the year ended December 31, 2022.

FEI's disclosure around its significant capital projects has not changed materially from those disclosed in the MD&A for the year ended December 31, 2022, with the exception of the following updates.

FEI expects to submit a supplementary filing with the BCUC in May 2023 for the OCU project to provide updates to key evidence in the proceeding, based on more recently available information. With respect to the TLSE project, the regulatory process was adjourned in March 2023 in order for FEI to prepare further information in support of the CPCN application. As a result, approval of both the OCU project and the TLSE project could be later than originally expected.

With respect to FEI's potential EGP project, in March 2023 FEI filed an application with the BCUC requesting approval of an amended rate schedule for Large Volume Industrial Transportation and two corresponding Transportation Agreements by May 2023, as directed by Order of the Lieutenant Governor in Council ("OIC"). Once approved, this will remove certain conditions of FEI for commencing construction.

In addition to the projected capital expenditures, FEI has a DSM Expenditures Plan which delivers a portfolio of energy efficiency and conservation measures and activities. In March 2023, the BCUC issued its decision and accepted FEI's DSM Expenditures Plan to incur approximately $141 million of expenditures in 2023 and include such expenditures as rate base additions.

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 related parties under common control for the quarters ended March 31 were as follows:

($ millions)	**2023**	2022
Operation and maintenance expense charged to FBC (a)	**2**	2
Total related party recoveries	**2**	2

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

Related Party Costs

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

($ millions)	**2023**	2022
Operation and maintenance expense charged by FBC (a)	**2**	1
Operation and maintenance expense charged by FHI (b)	**3**	3
Gas storage and purchases charged by ACGS (c)	**9**	13
Total related party costs	**14**	17

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

(b) FHI charged the Corporation for corporate management services and governance costs.

(c) 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 and other current assets 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, were as follows:

	March 31, 2023		December 31, 2022	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(1)**	-	(2)
ACGS	**-**	**-**	-	(4)
Total due to related parties	**-**	**(1)**	-	(6)

FINANCIAL INSTRUMENTS

Derivative Instruments

There were no material changes with respect to the nature and purpose, methodologies for fair value determination, and carrying values of the Corporation's natural gas contract derivatives from that disclosed in the MD&A for the year ended December 31, 2022. Additional details are provided in the notes to the Condensed Consolidated Interim Financial Statements.

As at March 31, 2023, natural gas contract derivatives 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, 2023**	December 31, 2022
Unrealized net loss recorded to current regulatory assets	**126**	60

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, excluding unamortized debt issuance costs, and estimated fair value of the Corporation's long-term debt:

		As at			
		March 31, 2023		December 31, 2022	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,295**	**3,226**	3,295	3,101

ACCOUNTING MATTERS

New Accounting Policies

FEI considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board ("FASB"). During the quarter ended March 31, 2023, there were no ASUs issued by FASB that have a material impact on these Condensed Consolidated Interim Financial Statements.

Future Accounting Pronouncements

Any ASUs issued by FASB that are not included in this MD&A were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on these Condensed Consolidated Interim Financial Statements.

OTHER DEVELOPMENTS

Collective Agreements

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 employees in specified occupations in the areas of administration and operations support expires on June 30, 2023. The second collective agreement, representing customer service employees, expired on March 31, 2022, and negotiations are ongoing.

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expires on March 31, 2024. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

BUSINESS RISK MANAGEMENT

The business risks of the Corporation remain substantially unchanged from those outlined in the Corporation's MD&A for the year ended December 31, 2022.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 365,988,987 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.

For further information, please contact:

Ian Lorimer
Vice President, Finance and Chief Financial Officer
Tel: (250) 469-8013
Email: ian.lorimer@fortisbc.com

FortisBC Energy Inc.
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia V6E 4M3

Website: www.fortisbc.com