FORTIS BC™

FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Year Ended December 31, 2023

February 8, 2024

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 Annual Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2023 and 2022, 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. On November 1, 2023, FHI sold its ownership of ACGS to an entity not related to Fortis, after which ACGS ceased to be a related party to the Corporation.

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 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; the time period in which FEI expects to file further information in support of its CPCN application for the TLSE Project; the Corporation's estimated contractual obligations; the Corporation's expectation to continue to increase the proportion of renewable gas into its gas supply portfolio; and the expected timing of the British Columbia Utilities Commission's decision with respect to FEI's proposed amendments to its RNG Program.

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, health and safety issues; the ability to maintain, replace or expand the Corporation's assets; the availability of natural gas supply; the ability to obtain and maintain applicable permits; that 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 (including absence of adverse rating actions by credit rating agencies); absence of interest costs risks; continued energy demand, population growth and new housing starts; the absence of counterparty credit risk; 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 2027 or earlier; and the absence of damages, fines, or penalties arising from 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; asset breakdown, operation, maintenance and expansion risk; natural gas supply risk; permits risk; risks related to Indigenous rights and engagement; underinsured and

uninsured losses; capital resources and liquidity risk; interest costs 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 this MD&A.

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 1,086,500 residential, commercial, industrial, and transportation customers through approximately 51,600 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 British Columbia Utilities Commission ("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

Allowed Return on Equity and Capital Structure

In January 2021, the BCUC announced that a Generic Cost of Capital ("GCOC") Proceeding was being initiated, including a review of the deemed common equity component of total capital structure and the allowed Return on Equity ("ROE") on common equity for regulated utilities in BC. The BCUC determined the GCOC Proceeding would move forward in stages. The first stage addressed 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 Stage 2.

In September 2023, the BCUC issued its decision on Stage 1 of the GCOC Proceeding ("GCOC Stage 1 Decision") for FEI and FBC. In its decision, the BCUC determined that FEI's deemed equity component of capital structure and allowed ROE will change from 38.5 per cent and 8.75 per cent to 45 per cent and 9.65 per cent, respectively, effective January 1, 2023. The BCUC also determined that neither a formulaic ROE automatic adjustment mechanism nor specific criteria or other triggers for future cost of capital proceedings are warranted, and instead will remain in effect until otherwise determined by the BCUC.

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 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 2023 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 approximately $5,945 million, which is inclusive of the Demand Side Management ("DSM") Expenditures Plan that was accepted by the BCUC in March 2023.

As part of the GCOC Stage 1 Decision, FEI was directed to file a Compliance Filing for permanent 2023 rates within thirty days. In September 2023, FEI filed the Compliance Filing which included a deferral of the 2023 revenue deficiency resulting from the GCOC Stage 1 Decision, and a request for approval to make 2023 interim rates permanent. As part of the Compliance Filing, FEI also proposed to refinance the capital structure in either the fourth quarter of 2023 or first quarter of 2024, and in December 2023 FEI received a $300 million equity injection from the Corporation's parent company, FHI, to align with the new deemed equity component of capital structure as approved in the GCOC Stage 1 Decision. The BCUC approved the Compliance Filing in October 2023. The Compliance Filing included a 2023 forecast average rate base of $5,945 million.

In July 2023, FEI filed a request for approval of 2024 delivery rates under the MRP and in October 2023, FEI filed an Evidentiary Update to incorporate the GCOC Stage 1 Decision. In December 2023, the BCUC approved a 2024 delivery rate increase of 8.00 per cent over 2023 rates, on an interim and refundable basis pending the outcome of the 2024-2027 DSM Expenditures Plan Application, which was subsequently approved in February 2024. The interim and refundable rate increase includes a 2024 forecast average rate base of approximately $5,817 million. As part of this decision, a further increase to the revenue deficiency deferral established in 2023 resulting from the GCOC Stage 1 Decision was approved for 2024.

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.

Price Risk Mitigation Application

In June 2023, the BCUC approved FEI's Price Risk Mitigation Application to implement fixed price financial derivatives as a strategy to limit the exposure to fluctuations in natural gas prices for customers who receive commodity supply from FEI. This approval builds on FEI's existing pricing strategy and will allow the enhanced use of these financial derivative instruments for up to a certain amount of FEI's annual baseload commodity portfolio, for the term beginning in April 2024. The settlement of these transactions will be captured in the Commodity Cost Reconciliation Account ("CCRA").

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 years ended December 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, and to decrease the commodity rate effective January 1, 2023, April 1, 2023, July 1, 2023, and October 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.

Directions to the BCUC

In November 2013, the BC Provincial government issued an Order of the Lieutenant Governor in Council ("2013 OIC") directing the BCUC to allow the Corporation to undertake the Tilbury Expansion Project at Tilbury Island in Delta, BC. The 2013 OIC and the subsequent amendments made to the OIC by the BC Provincial government in December 2014 and March 2017 set out a number of requirements for the BCUC as follows:

- to exempt the Tilbury Expansion Project from a Certificate of Public Convenience and Necessity ("CPCN") process (a CPCN process is typically required when a utility seeks approval for a major capital project and the utility must provide information related to the project needs and justifications, cost estimates, alternatives and customer impacts);
- to allow the Tilbury Expansion Project to proceed in two phases (Phase 1A, comprised of an additional Liquefied Natural Gas ("LNG") storage tank, completed in 2018, and truck loading facilities; and Phase 1B, comprised of additional liquefaction and dispensing);
- to impose an upper limit of $425 million on capital costs before development costs and construction carrying costs related to the Tilbury Phase 1A Expansion Project;
- to impose an upper limit of $400 million on capital costs before development costs and construction carrying costs related to the Tilbury Phase 1B Expansion Project;
- to allow for recovery of the costs of the Tilbury Expansion Project from customers;
- to amend the tariff rates for LNG customers served from FEI's LNG facilities;
- to exempt from a CPCN process the pipeline and compression facilities (the Eagle Mountain Gas Pipeline ("EGP") Project) that would supply the Woodfibre LNG facility near Squamish, BC should such facility proceed;
- to exempt from a CPCN process certain transmission projects, including one to increase the transmission line capacity to the Corporation's Tilbury LNG Facility; and
- to provide the methodologies for regulatory treatment of certain of the costs of these various projects.

During 2017, the Provincial government amended the Greenhouse Gas Reductions Regulations ("GGRR") to allow specified amounts of FEI investment in infrastructure and incentive funding to further expand the FEI natural gas for transportation ("NGT") programs, for a total of $330 million. Specifically, incentives toward LNG powered marine and rail, incentives toward NGT customers that consume natural gas procured from biomass or biogas sources, and investments in related LNG bunkering infrastructure and assets required to enable the development of LNG bunkering capability to fuel LNG powered marine vessels calling at ports in BC, were allowed under the amended GGRR to be included in FEI's regulated rate base, if certain conditions are met. These GGRR incentives expired on March 31, 2022. In addition, in the same GGRR amendment, the Provincial government authorized the utility to acquire Renewable Natural Gas ("RNG") of up to 5 per cent of its non-bypass supply portfolio provided the RNG costs are no more than $30 per gigajoule ("GJ").

In July 2021, the Provincial government announced further amendments to the GGRR to enable increased acquisition of renewable gases, including RNG. The amendments include:

- Increasing the amount of renewable gas FEI can acquire from 5 per cent to 15 per cent of non-bypass supply portfolio;
- Enabling FEI to acquire hydrogen, lignin and synthesis gas as well as RNG; and
- Increasing the price cap for the acquisition of renewable gas to $31 per GJ, indexed to inflation.

In May 2023, the Provincial government announced further amendments to the GGRR to allow up to $200 million towards zero-emission vehicle incentives and investments in zero-emission charging and hydrogen fueling infrastructure. These GGRR incentives will expire on March 31, 2030.

FEI's opportunities under the GGRR and future successive legislation to further expand its investments in NGT and LNG for domestic use, as well as expand its investment into and supply of renewable gas, support the transition to a lower carbon economy pursuant to policies established by various levels of government.

FORTIS BC

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year		
Periods ended December 31	**2023**	2022	Variance	**2023**	2022	Variance
Gas sales *(petajoules)*	**66**	75	(9)	**213**	231	(18)
($ millions)						
Revenue	**538**	724	(186)	**1,937**	2,083	(146)
Cost of natural gas	**175**	416	(241)	**756**	1,055	(299)
Operation and maintenance	**102**	87	15	**321**	292	29
Property and other taxes	**21**	18	3	**81**	72	9
Depreciation and amortization	**77**	75	2	**309**	302	7
Total expenses	**375**	596	(221)	**1,467**	1,721	(254)
Operating income	**163**	128	35	**470**	362	108
Add: Other income	**93**	37	56	**293**	123	170
Less: Finance charges	**125**	68	57	**422**	246	176
Earnings before income taxes	**131**	97	34	**341**	239	102
Income tax expense	**4**	6	(2)	**3**	11	(8)
Net earnings	**127**	91	36	**338**	228	110
Net earnings attributable to non-controlling interests	**-**	-	-	**1**	1	-
Net earnings attributable to controlling interest	**127**	91	36	**337**	227	110

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

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**36**	Net earnings for the quarter ended December 31, 2023 were $127 million compared to a $91 million for the same period in 2022. The increase was primarily due to an increase in FEI's deemed equity component of capital structure from 38.5 per cent to 45 per cent, and an increase in allowed ROE from 8.75 per cent to 9.65 per cent, resulting from the GCOC Stage 1 Decision. The net impact of the change in cost of capital was $11 million in the quarter. Net earnings for 2022 are based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent. In addition to the above, the increase was due to: • a $15 million higher income tax benefit, as a result of the Corporation implementing a tax loss utilization plan ("TLUP") in 2023 for a larger investment amount than a TLUP implemented in 2022, and • a higher investment in regulated assets, partially offset by • lower favourable variances primarily attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2022.
Revenue	**(186)**	The decrease in revenue was primarily due to: • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory liability, compared to the prior year, partially offset by • an increase in revenue associated with regulatory deferrals, including the revenue deficiency deferral for 2023 established as a result of the GCOC Stage 1 Decision, and

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
		• an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets. Gas sales volumes were lower than the same quarter in the previous year due to lower consumption by residential, commercial and transportation customers. Variances 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 net impact on total revenue compared to what is approved in rates in the current year.
Cost of natural gas	**(241)**	The decrease was primarily due to: • a lower commodity cost, approved by the BCUC, of $2.230 per gigajoule ("GJ") for the fourth quarter of 2023, as compared to $5.907 per GJ for the fourth quarter of 2022, • a decrease in total consumption 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, partially offset by • a higher storage and transport cost, approved by the BCUC, of $1.543 per GJ for the fourth quarter of 2023, as compared to $1.505 per GJ for the fourth quarter of 2022. 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 fourth 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 fourth quarter of 2023.
Operation and maintenance	**15**	The increase was primarily due to inflationary increases that contributed to an increase in regulated operating costs that are flowed through or shared with customers, higher costs associated with FEI's integrity management program, higher labour and contracting costs, the timing of incurring operating costs, and a higher service cost component of pension and other post-employment benefits ("OPEB") expense.
Other income	**56**	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 is recognized as a credit to other income. As part of the TLUP implemented in 2023, the Corporation received dividend income from FHI relating to a $4,700 million (2022 - $3,000 million) investment in preferred shares. The increase was primarily due to higher dividend income due to FEI having a TLUP in place in 2023 for a larger investment amount and a higher dividend rate than the TLUP implemented in 2022, as well as unwinding the TLUP later in the fourth quarter of 2023 compared to 2022, a higher equity component of AFUDC used in financing construction in 2023 due to an increase in the equity component and an increase in ROE resulting from the GCOC Stage 1 Decision, an increase in the non-service cost component of pension and other post-employment benefits, and an increase in interest income earned on cash balances held during the period.
Finance charges	**57**	The increase was primarily due to FEI having a TLUP in place for a larger investment amount and a higher interest rate than the TLUP implemented in 2022, as well as unwinding the TLUP later in the fourth quarter of 2023 compared to 2022, as well as 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.

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

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**110**	For the year ended December 31, 2023, net earnings were $337 million compared to $227 million for the same period in 2022. The increase was primarily due to: • a net impact of $46 million resulting from an increase in FEI's deemed equity component of capital structure and an increase in allowed ROE resulting from the GCOC Stage 1 Decision, • a $43 million higher income tax benefit as a result of the Corporation implementing a TLUP earlier in the second quarter of 2023 and for a larger investment amount than a TLUP implemented in 2022, • 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.
Revenue	**(146)**	The decrease in revenue was primarily due to: • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year, partially offset by • an increase in revenue associated with regulatory deferrals, including the revenue deficiency deferral for 2023 established as a result of the GCOC Stage 1 Decision, • an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, and • an increase in gas mitigation incentive revenue. For the year ended December 31, 2023, gas sales volumes were lower compared to the same period in 2022 primarily due to lower consumption by residential, commercial and transportation customers.
Cost of natural gas	**(299)**	The decrease was primarily due to: • a decrease in total consumption by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity, • an increase in the refund of the MCRA gas storage and transport cost regulatory liability compared to the prior year, • a lower commodity cost, approved by the BCUC, of $2.230 per GJ for the fourth quarter of 2023, as compared to $5.907 per GJ for the fourth quarter of 2022, • a lower commodity cost, approved by the BCUC, of $3.159 per GJ for the third quarter of 2023, as compared to $5.907 per GJ for the third quarter of 2022, and • a lower commodity cost, approved by the BCUC, of $4.159 per GJ for the second quarter of 2023, as compared to $4.503 per GJ for the second quarter of 2022, partially offset by • a higher commodity cost, approved by the BCUC, of $5.159 per 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 2023, as compared to $1.505 per GJ for 2022.
Operation and maintenance	**29**	The increase was primarily due to the same reasons as identified in the quarter.
Property and other taxes	**9**	The increase was primarily due to a higher assessed value of assets and an increase in rates charged by municipalities.
Depreciation and amortization	**7**	The increase was primarily due to a higher depreciable asset base compared to 2022, partially offset by a higher amortization of regulatory liabilities.

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Other income	**170**	The increase was primarily due to the same reasons as identified in the quarter, and FEI having a TLUP in place earlier in the second quarter of 2023 than the TLUP implemented in 2022.
Finance charges	**176**	The increase was primarily due to the same reasons as identified in the quarter, and FEI having a TLUP in place earlier in the second quarter of 2023 than the TLUP implemented in 2022.
Income tax expense	**(8)**	The decrease was primarily due to a higher TLUP tax recovery, partially offset by higher earnings before income tax, higher taxable temporary differences associated with amortization of certain regulatory assets and liabilities, and lower deductible temporary differences associated with property, plant and equipment.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2022 through December 31, 2023. 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)		
December 31, 2023	538	127
September 30, 2023	291	44
June 30, 2023	358	44
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

[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, 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.

December 2023/2022 - Net earnings were higher due to an increase in FEI's deemed equity component of capital structure from 38.5 per cent to 45 per cent, and an increase in allowed ROE from 8.75 per cent to 9.65 per cent, resulting from the GCOC Stage 1 Decision. The net impact of the change in cost of capital was $11 million in the quarter. The increase was also due to a $15 million higher income tax benefit as a result of the Corporation implementing a TLUP in 2023 for a larger investment amount than a TLUP implemented in 2022, and a higher investment in regulated assets, partially offset by lower favourable variances primarily attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2022.

September 2023/2022 - Net earnings were higher due to an increase in FEI's deemed equity component of capital structure from 38.5 per cent to 45 per cent, and an increase in allowed ROE from 8.75 per cent to 9.65 per cent, resulting from the GCOC Stage 1 Decision. The year-to-date impact of the change in cost of capital was $35 million and was recognized in the third quarter due to the timing of receiving the BCUC's decision, which included an effective date of January 1, 2023. The increase was also due to a $14 million higher income tax benefit as a result of the Corporation implementing a TLUP in 2023 for a larger investment amount than the TLUP implemented in 2022, and a higher investment in regulated assets.

June 2023/2022 - Net earnings were higher due to a $15 million higher income tax benefit as a result of the Corporation implementing a TLUP earlier in the second quarter of 2023 and for a larger investment amount than the TLUP implemented in 2022, a higher investment in regulated assets, higher favourable regulated variances

primarily 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.

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

CONSOLIDATED FINANCIAL POSITION

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

Balance Sheet Account	**Increase (Decrease)** *($ millions)*	**Explanation**
Cash	**(42)**	The decrease was primarily due to the receipt of a cash deposit in 2022 relating to development expenditures to be incurred for the EGP project for which there was no equivalent deposit at year-end 2023.
Accounts receivable and other current assets, net	**(184)**	The decrease was primarily due to: • lower tariff-based trade receivables, primarily as a result of decreased consumption due to warmer weather in the fourth quarter of 2023 as compared to the fourth quarter of 2022, • lower gas cost mitigation receivables, and • a change in the fair value of natural gas derivatives, partially offset by • a change in income tax receivable, which was in a payable position in 2022.
Inventories	**(41)**	The decrease was primarily due to a lower weighted average cost of natural gas, partially offset by a higher volume of natural gas in storage.
Regulatory assets (current and long-term)	**240**	The increase was primarily due to: • an increase in deferred income tax liabilities, the offset of which is deferred as a regulatory asset, • an increase in unrecognized actuarial losses in defined benefit pension and OPEB plans, the offset of which moved from a regulatory liability position as at December 31, 2022 to a regulatory asset position as at December 31, 2023, • an increase in DSM expenditures, • a $48 million regulatory asset recognized related to the revenue deficiency deferral for 2023 established as a result of the GCOC Stage 1 Decision, • project development costs related to the OCU project, which were transferred from property, plant and equipment in 2023 based on direction from the BCUC, and • the change in fair market value of natural gas derivatives, partially offset by • a lower CCRA regulatory asset due to costs recovered in customer rates exceeding commodity costs incurred.
Property, plant and equipment, net	**346**	The increase was primarily due to capital expenditures of $573 million, changes in accrued capital expenditures of $76 million, and $14 million in equity AFUDC, less: • depreciation expense, excluding net salvage provision, of $199 million, • contributions in aid of construction ("CIAC") of $80 million, • costs of removal of $19 million incurred, which are recognized against the net salvage provision in regulatory liabilities, and • $18 million of project development costs related to the OCU project which were transferred to regulatory assets in 2023 based on direction from the BCUC.
Credit facilities	**(138)**	The decrease was primarily a result of net repayments from a $300 million equity injection received in December 2023, partially offset by borrowings used to fund the debt component of FEI's capital expenditure program and working capital changes in the year.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Accounts payable and other current liabilities	**(136)**	The decrease was primarily due to: • a decrease in cash deposits held relating to development expenditures incurred for the EGP project, as the amounts previously held were fully applied on EGP development costs, • lower gas cost payables, due to a lower weighted average cost of gas purchased, and • a change in income tax payable to a receivable position in 2023, partially offset by • higher accrued capital expenditures.
Deferred income tax	**84**	The increase was primarily due to higher deductible temporary differences associated with property, plant and equipment, utilization of deposits held relating to development expenditures incurred for the EGP project in the year, and lower taxable temporary differences associated with certain regulatory asset and liability accounts, partially offset by non-capital losses carried forward.
Other liabilities (long-term)	**70**	The increase was primarily due to an increase in the unfunded status of the Corporations defined benefit pension and OPEB plans, which was primarily driven by a decrease in the discount rate used to measure the projected benefit obligation, and an increase in operating lease obligations, partially offset by a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**400**	The increase was due to equity injections received from the Corporation's parent company, FHI. During the first quarter of 2023, $100 million was received, the proceeds of which were used to support the equity component of FEI's capital expenditure program, and in December 2023, $300 million was received to align with the new deemed equity component of capital structure as approved in the GCOC Stage 1 Decision.

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 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. 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. During the third quarter of 2023, as a result of the GCOC Stage 1 Decision discussed in the "Regulation" section of this MD&A, the approved deemed equity component of capital structure was updated from 38.5 per cent to 45 per cent, and the approved debt component of capital structure was updated from 61.5 per cent to 55 per cent, both effective as of January 1, 2023. In late September 2023, FEI filed a Compliance Filing which included a proposal to refinance the capital structure in either the fourth quarter of 2023 or first quarter of 2024, and in December 2023 FEI received a $300 million equity injection from the Corporation's parent company, FHI, to align with the new deemed equity component of capital structure as approved in the GCOC Stage 1 Decision.

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

Years Ended December 31	2023	2022	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**535**	612	(77)
Investing activities	**(604)**	(659)	55
Financing activities	**27**	86	(59)
Net change in cash	**(42)**	39	(81)

Operating Activities

Cash from operating activities was $77 million lower compared to the same period in 2022 primarily due to changes in regulatory assets and liabilities and changes in working capital, partially offset by higher net earnings after non-cash adjustments.

Investing Activities

Cash used in investing activities was $55 million lower compared to the same period in 2022 primarily due to lower overall capital expenditures during 2023 compared to 2022, partially offset by higher DSM expenditures. Higher CIAC received during 2023 was from Woodfibre LNG and related to initial construction costs on the EGP project that are reflected in capital expenditures beginning in September 2023.

Financing Activities

Cash from financing activities was $59 million lower compared to the same period in 2022. During 2023, proceeds from common share issuances totaling $400 million were used to repay existing credit facilities, as compared to the same period in 2022 where net proceeds from a $150 million debenture issuance and a $150 million issuance of common shares were used for repayments on the credit facility.

During 2023, FEI paid common share dividends of $240 million (2022 - $170 million) to its parent company, FHI. In December 2023 FEI received a $300 million equity injection from the Corporation's parent company, FHI, to align with the new deemed equity component of capital structure as approved in the GCOC Stage 1 Decision.

Contractual Obligations

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

As at December 31, 2023	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 obligations on long-term debt	**2,496**	**152**	**152**	**150**	**148**	**148**	**1,746**
Long-term debt [1]	**3,295**	**-**	**-**	**150**	**-**	**-**	**3,145**
Gas purchase obligations (a)	**4,772**	**498**	**420**	**359**	**326**	**238**	**2,931**
Other (b)	**38**	**23**	**6**	**6**	**3**	**-**	**-**
Total	**10,601**	**673**	**578**	**665**	**477**	**386**	**7,822**

[1] Excludes unamortized debt issuance costs.

(a) The Corporation enters into contracts to purchase natural gas, renewable gas, and natural gas transportation and storage services from various suppliers. These contracts are used to ensure that there is an adequate supply of natural gas and renewable gas to meet the needs of customers and to minimize exposure to market price fluctuations. The natural gas purchase obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2023.

The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers. During 2022, FEI entered into certain long-term supply agreements to acquire renewable gas over a 20-year period from a portfolio of landfill sites and from an anaerobic digester facility, up to a combined maximum annual volume of 9.3 petajoules. Both agreements were approved by the BCUC.

(b) Included in other contractual obligations are building and vehicle leases, and defined benefit pension plan funding obligations.

In January 2012, two unrelated parties collectively purchased a 15 per cent equity interest in the Mt. Hayes Storage Limited Partnership ("MHLP"), which at the time was a wholly owned limited partnership of the Corporation. These non-controlling interest owners hold a put option which, if exercised, would oblige the Corporation to purchase the non-controlling interest owners' 15 per cent voting share in MHLP for cash. For rate-making purposes, these non-controlling interests are considered equity and if FEI was required to purchase these non-controlling interests, FEI would fund the transaction with an equity issuance. Accordingly, the Corporation has presented these redeemable non-controlling interests as equity.

Off-Balance Sheet Arrangements

As at December 31, 2023, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $36 million (December 31, 2022 - $54 million) primarily to support the Corporation's unfunded supplemental pension benefit plans.

Capital Structure

The Corporation's principal business of regulated natural gas transmission and distribution requires ongoing access to capital in order to allow the Corporation to fund the maintenance, replacement and expansion of infrastructure. The Corporation maintains a capital structure in line with the deemed regulatory capital structure approved by the BCUC. During the third quarter of 2023, as a result of the GCOC Stage 1 Decision discussed in the "Regulation" section of this MD&A, the approved deemed equity component of capital structure was updated from 38.5 per cent to 45 per cent, and the approved debt component of capital structure was updated from 61.5 per cent to 55 per cent, both effective as of January 1, 2023. This capital structure excludes the financing of goodwill and other non-regulated items that do not impact the deemed capital structure. As part of the last review performed and the resulting GCOC Stage 1 Decision, the BCUC determined that the common equity component of capital structure and ROE for FEI will remain in effect until otherwise determined by the Commission.

Credit Ratings

Debentures issued by the Corporation are rated by Morningstar DBRS and Moody's Investors Service ("Moody's"). The ratings assigned to the debentures issued by the Corporation are reviewed by these agencies on an ongoing basis and are summarized as follows:

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

In December 2023, Morningstar DBRS and Moody's issued updated credit rating reports confirming the Corporation's debenture ratings and outlook.

Credit Facilities and Debentures

Credit Facilities

As at December 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 December 31, 2023, which matures in March 2024.

The following summary outlines the Corporation's credit facilities as at December 31:

($ millions)	**2023**	2022
Operating credit facility	**700**	700
Letter of credit facility	**55**	55
Draws on operating credit facility	**(65)**	(203)
Letters of credit outstanding	**(36)**	(54)
Credit facilities available	**654**	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 December 31, 2023, $650 million remains available under the MTN Debenture Program.

Dividend Restrictions

As part of its approval of the acquisition of FHI by Fortis, the BCUC imposed the continuation of a number of conditions intended to ring-fence the Corporation from FHI. These restrictions included a prohibition on the payment of dividends unless the Corporation has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. The BCUC approved, for 2023 only, a variance from these ring-fencing conditions as FEI was unable to fully implement the revised capital structure from the GCOC Stage 1 Decision for 2023.

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 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 2024 projected capital expenditures are approximately $764 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 2024 projected capital expenditures are dependent on timing of spending on multi-year capital projects, based in part on the timing of any remaining regulatory and permitting approvals required for certain projects. Included in the 2024 projected capital expenditures is approximately $250 million expected to be spent by FEI during 2024 on the EGP Project. As explained further below, FEI started initial construction activities in September 2023, which were funded through contributions received from Woodfibre LNG as part of an agreement which stipulates that FEI's funding commencement date begins January 1, 2024, up to an amount of $400 million before contributions from Woodfibre LNG begin again.

The 2023 capital expenditures were $589 million, inclusive of AFUDC and excluding CIAC.

Included in these projected capital expenditures are more significant projects further described below.

Energy Transition to Low Carbon Future

FEI and FBC have established a Clean Growth Pathway plan to reduce its customers' Greenhouse Gas ("GHG") emissions. For FEI, the plan includes investment in low and zero carbon vehicles and infrastructure in the transportation sector, growth in renewable gas alternatives into the renewable energy portfolio, LNG infrastructure to position BC as a leading global LNG provider, and energy efficiency programs and developing innovative energy solutions for homes and businesses. Certain of these investments are part of the Corporation's projected capital expenditures, and are further described in this section, as well as under "Directions to the BCUC", and "Other Capital Projects" sections of this MD&A.

Inland Gas Upgrades ("IGU") Project

In December 2018, FEI filed a CPCN application, in the amount of approximately $310 million to be incurred primarily between 2021 and 2024, to implement cost effective integrity management solutions to mitigate potential integrity issues within the interior region of BC. The CPCN application was approved by the BCUC in January 2020, and construction will be substantially complete in 2025.

Advanced Metering Infrastructure ("AMI") Project

In May 2021, FEI filed a CPCN application, in the amount of approximately $520 million, excluding AFUDC and project management costs, to automate the meter reading process for FEI customers, providing better information access to customers as well as operational opportunities that support the safety, resiliency, and efficient operation of the gas distribution system. The CPCN application was approved by the BCUC in May 2023, and construction will be substantially complete in 2028.

Transmission Integrity Management Capabilities ("TIMC") Project

The multi-year TIMC Project, which will be carried out in several phases, is focused on improving gas line safety and the integrity of the transmission system, including gas line modifications and looping. In May 2022, FEI's CPCN application for the Coastal Transmission System component of the TIMC Project, in the amount of approximately $120 million, was approved by the BCUC. In September 2022, FEI's CPCN application for the Interior Transmission System component of the TIMC Project, in the amount of approximately $75 million, was submitted to the BCUC. The CPCN application was approved by the BCUC in January 2024.

Okanagan Capacity Upgrade ("OCU") Project

In November 2020, FEI filed a CPCN application, in the amount of approximately $200 million, to construct a new section of pipeline and associated facilities to address expected gas load growth in the Okanagan. The OCU Project would add adequate capacity so that FEI can continue to provide long-term safe and reliable gas service to its customers in the region. In December 2023, the BCUC issued a Decision denying FEI's CPCN for the OCU Project, stating that it may not be the optimal solution to address the imminent capacity shortfall, and approved the establishment of a deferral account to capture development costs FEI has already incurred. As part of the Decision, FEI was also asked to address the capacity shortfall with potential short-term mitigation solutions in a future filing, which could be a rescope of the OCU Project, if necessary, or an application similar to the current one. FEI will be determining its next steps with the BCUC on the OCU Project in mid-2024.

Tilbury LNG Storage Expansion ("TLSE")

In December 2020, FEI filed a CPCN application, in the amount of approximately $540 million, to replace the original Tilbury Base Plant with a new storage tank, as well as regasification capacity, to improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system. The improvement in resiliency will also bring ancillary benefits to system operations and customers. In addition to BCUC approval, the TLSE project is also subject to various Environmental Assessment processes requiring approval. In March 2023, the regulatory process was adjourned in order for FEI to prepare further information in support of the CPCN application, which FEI expects to file in mid-2024.

Tilbury Phase 1B Expansion Project

This project consists of construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and optimizing the existing investment in the Tilbury Phase 1A Expansion Project. As explained under "Directions to the BCUC" above, the project has received an OIC from the BC Provincial government that allows for investment of up to $400 million of capital costs before development costs and construction carrying costs. During 2024, FEI will continue to evaluate the investment opportunity and proceed with necessary pre-Front-End Engineering Design ("FEED") and FEED studies.

Eagle Mountain Pipeline ("EGP") Project

This project expands FEI's existing natural gas system to supply Woodfibre LNG's export facility near Squamish, BC. Through this project, FEI would install 50 kilometers of new natural gas pipeline between Squamish and Coquitlam, as well as supporting infrastructure such as a new compressor station at the Woodfibre LNG site and upgrades to the existing compressor station in Coquitlam.

FEI and Woodfibre LNG had previously entered into a pre-execution work agreement, along with subsequent amendments and ancillary commercial agreements ("WFLNG Agreements"), that established the amount and timing of funding requirements to be provided by Woodfibre LNG to FEI for project feasibility and development costs prior to construction, and capital expenditures during construction and into commissioning. Throughout 2023, FEI has continued to receive deposit funding from Woodfibre LNG under the WFLNG Agreements for development expenditures incurred for the EGP Project. In addition, FEI received approval from the BCUC, as directed by an OIC, in May 2023 for an amended rate schedule for Large Volume Industrial Transportation and two corresponding Transportation Agreements, which included an increase to $750 million of net investment by FEI, in accordance with WFLNG Agreements, compared to the $420 million previously. In August 2023, FEI either waived or satisfied remaining conditions under the WFLNG Agreements to move forward with initial construction activities, which started in September 2023. Capital expenditures incurred from September to

December 2023 were funded through contributions received from Woodfibre LNG and, as stipulated in the WFLNG Agreements, FEI's funding commencement date begins January 1, 2024 which will result in FEI incurring capital expenditures up to an amount of $400 million initially before contributions from Woodfibre LNG begin again, with up to an additional $350 million of FEI investment upon project completion in 2027.

As explained under "Directions to the BCUC" above, the BC Provincial government issued an OIC that grants FEI an exemption from the requirement to seek a CPCN approval from the BCUC for the EGP Project. FEI's anticipated capital expenditures, net of forecasted customer contributions from Woodfibre LNG, are $750 million by the time the project is complete in 2027.

Other Capital Projects

In addition to the above, beyond 2023 the Corporation continues to pursue additional LNG infrastructure investment opportunities in BC, including a further expansion of Tilbury that would help position BC as a vital domestic and international LNG provider to lower global GHG emissions, consistent with the Corporation's Clean Growth Pathway. As explained under "Directions to the BCUC" above, the BC Provincial government issued an OIC that grants FEI exemptions from the requirement to seek CPCN approvals from the BCUC for certain further expansions at the Tilbury site, subject to certain conditions.

With respect to further Tilbury expansion, in February 2020, in conjunction with FEI's parent company FHI, an initial project description was filed with regulators to begin the federal impact assessment and provincial environmental assessment to further expand the Tilbury site. In January 2022, the project received a positive Readiness Decision related to the provincial environmental assessment, which allowed for a public comment period that ended in early 2022. This further expansion considers the potential increase to storage capacity and strengthening the resiliency of FEI's gas system, as included in the TLSE Project and related CPCN process, as well as enabling additional liquefaction capacity. In July 2022, FEI's parent company entered into an agreement with an Indigenous community to provide the ability to participate through equity ownership in certain future regulated LNG investments, which could include the TLSE Project and the Tilbury Phase 1B Expansion Project if the parties are able to satisfy certain obligations. Any proposed transaction is subject to regulatory approvals and certain conditions precedent.

DSM Expenditures Plan

In addition to these significant projects, 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 rate base expenditures in 2023. In July 2023, FEI filed a DSM Expenditures Plan to incur approximately $627 million of expenditures for the periods 2024 through 2027 and include such expenditures in as rate base additions, which was approved by the BCUC in February 2024.

BUSINESS RISK MANAGEMENT

The Corporation is subject to a variety of risks and uncertainties that may have a material adverse effect on the Corporation's results of operations and financial position.

Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. The ability of the Corporation to recover the actual costs of providing services and to earn the approved rate of return is impacted by achieving the forecasts established in the rate-setting process. The cost for upgrading existing facilities and adding new facilities requires the approval of the BCUC for inclusion in the rate base, at times through a CPCN if certain criteria are met. There is no assurance that CPCNs or capital projects perceived as required by the Corporation will be approved or that conditions to such approval will not be imposed.

Through the regulatory process, the BCUC approves the ROE that the Corporation is allowed to earn and the deemed capital structure. This regulatory process allows the Corporation a reasonable opportunity to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments, which is essential for on-going capital attraction and growth. However, there can be no assurance that the rate orders issued by the BCUC will permit the Corporation to recover all costs actually incurred and to earn the allowed rate of return. The BCUC periodically reviews the cost of capital for regulated utilities in BC, which could affect FEI's capital structure and allowed ROE. The timing of the next cost of capital review is not known. Any future

changes resulting from the next cost of capital review could materially impact the Corporation's earnings.

Rate applications that reflect cost of service and establish revenue requirements are subject to either a public hearing process which may be oral or written, or a negotiated settlement. The BCUC approved a rate-setting methodology for the Corporation for a term of 2020 through 2024 under the MRP. Rates during this term will be determined through a review process which will occur on an annual basis, however there can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the allowed rate of return.

A failure to obtain rates that recover the costs of providing service, or provide a reasonable opportunity to earn for a fair return, may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed upgrades or expansion projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, have a material adverse effect on the Corporation's results of operations and financial position.

There is legislation in BC which enables the BCUC to impose administrative monetary penalties on the Corporation, upon finding contravention of a BCUC order, rule, or standard. The penalty amount varies depending on the nature of the violation and it is not recoverable from customers.

Natural Gas Competitiveness

In the future, if natural gas becomes less competitive due to price or other factors, such as government policy or public perception of natural gas or its carbon intensity relative to other energy sources, the Corporation's ability to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates for remaining customers and, in an extreme case, could ultimately lead to an inability to fully recover the Corporation's cost of service in rates charged to customers.

In the Corporation's utility service territory, natural gas primarily competes for space and hot water heating load with electricity. In addition to other price comparisons, the upfront capital cost differences between electricity and natural gas equipment for hot water and space heating applications continue to present a challenge for the competitiveness of natural gas on a fully costed basis, including where electric applications are supported by government incentives and preferential tax treatment.

Government policy has also impacted the competitiveness of natural gas and the future use of natural gas in BC. Federally, the *Canadian Net-Zero Emissions Accountability Act* became law in June 2021 and establishes in legislation Canada's commitment to achieve net-zero emissions by 2050. Provincially, in October 2021, the Government of BC released an update to its economic and climate action plan, the *CleanBC Roadmap to 2030 ("CleanBC")*. Originally introduced in 2018, *CleanBC* frames BC's approach to reducing emissions and transitioning to a low-carbon economy. The update includes a series of actions designed to achieve the Government of BC's legislated climate targets to reduce GHG emissions by 40 per cent by 2030, based on 2007 levels. Among the initiatives outlined in *CleanBC* are a requirement that all new construction be zero-carbon by 2030, the introduction of a GHG emissions cap that will require gas utilities to undertake activities and invest in technologies to limit GHG emissions from buildings and industry to approximately 6 megatonnes by 2030, the phasing out of incentives for conventional gas-fired heating equipment, a commitment to increase the tax on carbon-based fuels to meet or exceed the federal benchmark of $170 per tonne by 2030, a new high efficiency standard requiring space and water heating equipment to meet or exceed 100 per cent efficiency after 2030, an end to efficiency rebates on conventional gas-fired equipment, and acceleration of zero-emission vehicle adoption with a target of 90 per cent of all new light-duty vehicle sales in the province being zero-emission by 2030. In addition, the Province provides significant incentives for electric heat pumps, including both rebates on equipment sales and exemption on provincial sales taxes, which is driving adoption of electric heat pumps and may erode new customer additions on the gas system. While *CleanBC* provides a path forward for the Province, further policy details, enabling regulation, and implementation plans are still to be released.

In response to climate policy, FEI has increased the proportion of renewable gas into its gas supply portfolio through committed supply contracts and expects to continue to increase the proportion of renewable gas into its gas supply portfolio; however, these supply costs are significantly higher than conventional natural gas, which could impact cost competitiveness relative to electricity. Furthermore, a portion of renewable gas supply may not be eligible for carbon tax credits. Current biomethane legislation does not allow for unsold renewable gas acquired in previous months to be eligible for a carbon tax refund, which could increase the total cost of gas supply, and which may not be recoverable through current BCUC approved deferral mechanisms allowing for the flow through of natural gas supply costs. An inability to flow through the full cost of gas supply could have

a material adverse effect on the Corporation's results of operations and financial position. FEI awaits a government decision to amend biomethane legislation to recognize the concept of biomethane inventory, which may mitigate this potential future liability. Additionally, technology may not develop at a fast enough rate, or at a low enough cost, such that high efficiency gas appliances are able to meet efficiency requirements in the *CleanBC* or other government policy requirements, which may impact the demand for natural gas.

There are other competitive challenges that are impacting the proportion of new homes that use natural gas, such as the carbon intensity of the energy source and type of housing stock being built. In addition, as part of their own climate change policy plans, local governments may use various tools at their disposal such as permits, building codes and zoning bylaws, or early adoption of government policy, to impose limitations on energy sources permitted in new and existing developments. The municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free options for their developments. These actions and policies may hinder the Corporation's ability to operate, attract new customers, or retain existing customers.

The collective impact of these policies could have a material adverse effect on the competitiveness of natural gas relative to non-carbon based energy sources, and increase the risk of underutilized or stranded utility assets.

Commodity Price Risk

A severe and prolonged increase in commodity costs could materially affect the Corporation despite regulatory measures available for collecting changes in commodity costs in customer rates. Increased investment in and procurement of renewable gas supply will also have an impact on commodity costs of the Corporation, which could further decrease the competitiveness of gas service in BC. There can be no assurance that the current BCUC approved flow through mechanisms in place allowing for the flow through of the gas supply costs to customers will continue in the future, as they are dependent on future regulatory decisions and orders. The Corporation currently has approval from the BCUC to enter into fixed price financial derivatives, for up to a certain amount of annual baseload capacity, as a strategy to limit the exposure to fluctuations in natural gas prices with the settlement of these transactions being captured in BCUC approved flow through mechanisms. An inability to flow through the full cost of gas to customers could have a material adverse effect on the Corporation's results of operations and financial position.

Climate Change

In addition to the seasonality of the Corporation's sales loads, climate change may cause more frequent and intense weather events, affect the temperature variability in the Corporation's service territory, and cause changes in the consumption pattern of the Corporation's customers, which in turn could have an impact on customer rates.

As further described under "Natural Gas Competitiveness", all levels of government have become more active in the development of policies to address climate change. For example, municipal governments have developed policies and bylaws to support the transition to a lower carbon economy. Additionally, CleanBC includes a series of initiatives at the provincial level that frames BC's approach to reducing emissions and transitioning to a low-carbon economy.

In response to climate change risks, the Corporation has established a Clean Growth Pathway plan to reduce its customers' GHG emissions. The plan includes, but is not limited to, investment in research and development of renewable gases, increased procurement of renewable gas, growth in the use of natural gas in the transportation and marine bunkering sectors, as well as increased expenditures for energy efficiency and conservation. These initiatives could lead to higher costs which ultimately result in higher rates and reduced price competitiveness.

The Corporation's investments to reduce its customers' emissions in transportation and marine bunkering sectors contribute to overall throughput and revenue. However, the energy demand in these sectors could be more volatile than domestic use and their increased share in the Corporation's load and revenue profiles could potentially lead to higher revenue and earnings volatility going forward.

Weather-related events arising from climate change could affect the Corporation's operations and system reliability, further described under "Weather and Natural Disasters". Responding to these changes in weather events could lead to increased costs associated with the strengthening of infrastructure to ensure system reliability and resiliency, which in turn could have an impact on customer rates. An increase in the severity and frequency of weather-related events could impact future operating, maintenance, replacement, expansion and removal costs that will be incurred in the ongoing operation of its business. In addition, the ability of customers to receive service from the Corporation may be impacted by weather-related events or longer term environmental effects arising from climate change. This may impact revenues collected by the Corporation,

which in turn could have an impact on customer rates.

Weather and Natural Disasters

The facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events, some of which could be caused by climate change. A major natural disaster, such as an earthquake, wildfire, flood, washout, landslide, avalanche or other similar natural event could severely damage the Corporation's natural gas transmission, distribution and storage systems and access to natural gas supply. Although the Corporation's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote or mountainous areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events.

The Corporation has limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions, changes in climate, or other natural disasters, an application would be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC would approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute natural gas to them in accordance with the Corporation's contractual obligations. Thus, any major damage to the Corporation's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount and could have a material adverse effect on the Corporation's results of operations and financial position.

Environment, Health and Safety Matters

The Corporation is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety, for which the Corporation incurs compliance costs. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. This process could lead to delays in project approvals and lengthier construction timelines, which could adversely affect the Corporation through increased operating and capital costs. In addition, an inability to acquire any necessary environmental approvals, especially those required for major projects needed to increase system capacity, could limit the Corporation's future growth opportunities. Potential environmental damage and costs could arise due to a variety of events, including severe weather and other natural disasters, human error or misconduct, or equipment failure. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs could have a material adverse effect on the Corporation's results of operations and financial position.

The Corporation is exposed to environmental risks that owners and operators of properties in BC generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. It is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Corporation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, environmental management for sensitive species and their habitat, and conducting environmental impact assessments and remediation. It is possible that other developments may lead to increasingly strict environmental and safety laws, regulations and enforcement policies and claims for damages to property or persons resulting from the Corporation's operations, any one of which could result in substantial costs or liabilities to the Corporation. Any regulatory changes that impose additional environmental restrictions or requirements on the Corporation or its customers could adversely affect the Corporation through increased operating and capital costs.

The Corporation is exposed to various operational risks, such as pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks or spills; and any other accidents involving natural gas, that could result in significant operational disruptions and/or environmental liability. The Corporation responds to spills and leaks and takes remedial steps

in accordance with environmental regulations and standards and sound industry practice; however, there can

be no assurance that the Corporation will not be obligated to incur further expenses in connection with changes in environmental regulations and standards or as a result of historical contamination.

Natural gas transmission, distribution and storage has inherent potential risks and there can be no assurance that substantial costs and liabilities will not be incurred. Potential environmental damage and costs could materialize due to some type of severe weather event or major equipment failure and there can be no assurance that such costs would be recoverable. Unrecovered costs could have a material adverse effect on the Corporation’s results of operations and financial position.

While the Corporation maintains insurance, the insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions which could result in delays between the occurrence of an insured loss and recovery through insurance proceeds. In addition, there can be no assurance that the possible types of liabilities that may be incurred by the Corporation will be covered by insurance as further described under “Underinsured and Uninsured Losses”.

Asset Breakdown, Operation, Maintenance and Expansion

The Corporation’s assets require ongoing maintenance, replacement and expansion. Accordingly, to ensure the continued performance of the physical assets, the Corporation determines expenditures that should be made to maintain, replace and expand the assets. The Corporation could experience service disruptions and increased costs if it is unable to maintain, replace or expand its asset base. The inability to recover, through approved rates, the costs of capital expenditures that the Corporation believes are necessary to maintain, replace, expand and remove its assets, the failure by the Corporation to properly implement or complete approved capital expenditure programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Corporation’s results of operations and financial position.

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenses that will be incurred in the ongoing operation of its business. Management’s analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. It is uncertain whether capital expenditures will, in all cases, receive regulatory approval for recovery in future customer rates. The inability to recover capital expenditures could have a material adverse effect on the Corporation’s results of operations and financial position.

Natural Gas Supply Risk

The Corporation is dependent on a limited selection of pipeline and storage providers. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods when regional pipeline and storage resources become constrained to serve the demand for natural gas in BC and the US Pacific Northwest. Fluctuations in the amount of natural gas used by customers can vary significantly in response to seasonal changes in weather and longer term changes in climate.

In addition, the Corporation is highly dependent on a single source transmission pipeline. In the event of a prolonged service disruption on the Westcoast transmission system, the Corporation’s customers could experience prolonged outages, thereby affecting revenues and incurring costs to safely relight customers. The Corporation uses LNG peak shaving facilities to mitigate this risk by providing limited short-term on-system supply during cold weather spells or emergency situations, but this will not mitigate the supply disruption risk posed by an extended transmission system outage.

Developments are occurring in the region that may increase the demand for gas supply from BC. These include an increase in pipeline capacity to deliver gas from BC to markets outside of BC and the potential development of large scale LNG facilities to export gas. BC has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. If large scale LNG facilities are constructed, it is expected to put pressures on supply in the region, and additional pipeline infrastructure will be needed to connect to market hubs. The pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation’s access to supply or the price of that supply. With respect to renewable gas, as FEI increases its commitment in its gas supply portfolio to meet customer or government policy requirements, there are risks of not being able to source enough renewable gas supply.

There can be no assurance that the current BCUC approved deferral mechanisms allowing for the flow through of natural gas supply costs will continue in the future, as they are dependent on future regulatory decisions and

orders. An inability to flow through the full cost of natural gas could have a material adverse effect on the Corporation's results of operations and financial position.

Permits

The acquisition, ownership and operation of natural gas businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies and Indigenous Peoples. For various reasons, including increased engagement requirements and expectations, the Corporation may not be able to obtain or maintain all required regulatory approvals on terms satisfactory to the Corporation. The external environment has become more complex with heightened expectations from permitting agencies, local municipalities and Indigenous Peoples to be able to review and provide feedback on projects. Increased engagement is, in many cases, driven by policy responses to climate change, but the resulting increases in cost and review timelines could negatively impact the Corporation's ability to meet project budgets and schedules. If there is a delay in obtaining any required regulatory approval or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the Corporation's ability to properly implement or complete approved capital expenditure programs could become limited and the operation of its assets and the distribution of natural gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's results of operations and financial position.

Indigenous Rights and Indigenous Engagement

The Corporation provides service to customers on Indigenous Peoples' lands and maintains gas facilities on lands that are subject to land claims by various Indigenous Peoples. There are various treaty and other agreement negotiation processes involving Indigenous Peoples and the Governments of BC and Canada that are underway, but the basis upon which settlements might be reached in the Corporation's service areas is not clear. Furthermore, not all Indigenous Peoples are participating in the processes. To date, the policy of the Government of BC has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Corporation. However, there can be no certainty that the settlement processes will not have a material adverse effect on the Corporation's results of operations and financial position.

Before issuing governmental or regulatory approvals (such as BCUC approvals and permits and authorizations under the *Energy Resource Activities Act*), the regulatory or governmental decision-maker will consider whether the Crown has a duty to consult Indigenous Peoples and, if necessary, to accommodate, and if so whether the consultation and accommodation have been adequate. In practice, the Crown often delegates procedural aspects of the duty to consult to the Corporation. If engagement and consultation with Indigenous groups are not addressed upfront, this may affect the timing, cost and likelihood of regulatory approval of certain of the Corporation's capital projects and result in higher costs to implement projects in the longer term. Indigenous groups are also participating in BCUC and other regulatory and governmental processes with increased regularity, with potentially opposing views, and the increased involvement can affect the time and ability to obtain CPCN and other approvals.

The Province's *Declaration on the Rights of Indigenous Peoples Act* ("*DRIPA*") and the federal government's *United Nations Declaration on the Rights of Indigenous Peoples Act* set out a process by which the provincial and federal governments will review their laws to ensure they are consistent with the United Nations Declaration on the Rights of Indigenous Peoples ("*UNDRIP*") and require that the provincial and federal governments develop an action plan to achieve the objectives of *UNDRIP*. The legislative review and action plans may result in amendments to provincial and federal legislation or policy, which may affect the Corporation. *DRIPA* also empowers the Province to enter into agreements with Indigenous governing bodies to provide for joint-decision making or to require consent of an Indigenous governing body before certain decisions are made. Legislative amendments and case law may increase uncertainty in permitting and regulatory processes, or could cause delays in receiving or failure to receive permits.

In 2020, the BCUC released its final report as part of its Indigenous Utilities Regulation Inquiry, with a number of recommendations that may enable the development of utilities controlled by Indigenous Peoples. As part of the report, the BCUC recommended that when considering a CPCN application, the economic development needs of Indigenous Peoples be considered, and that Indigenous Peoples may have the opportunity to acquire existing assets of incumbent utilities. If accepted by the BC Government, these recommendations could impact timing associated with obtaining CPCN approvals and the level of investment in utility assets.

Underinsured and Uninsured Losses

The Corporation maintains insurance coverage with respect to potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers as is considered appropriate, taking into account all

relevant factors, including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations and financial position.

In the event of an uninsured loss or liability, the Corporation would apply to the BCUC to recover the loss (or liability) through an increased tariff. However, there can be no assurance that the BCUC would approve any such application, in whole or in part. Additionally, delays between the occurrence of an uninsured loss (or liability) and recovery through an increased tariff could result in variability of results between periods. Any major damage to the Corporation's facilities could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's results of operations and financial position.

Capital Resources and Liquidity

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The Corporation's ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in BC, regulatory decisions regarding capital structure and ROE, the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies, and general economic conditions. In the future, the ability to arrange sufficient financing could also be impacted by investment policies that limit financing of natural gas utilities and projects. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation is subject to financial risk associated with changes in the credit ratings assigned by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Corporation's credit facility. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's finance charges. Also, a significant downgrade in the Corporation's credit ratings could trigger margin calls and other cash requirements under the Corporation's natural gas purchase and natural gas derivative contracts. Global financial crises and other debtholder concerns have placed scrutiny on rating agencies and rating agency criteria that may result in changes to credit rating practices and policies.

Volatility in the global financial and capital markets may increase the cost of and affect the timing of issuance of long-term capital by the Corporation.

Interest Costs

The Corporation is exposed to interest rate risks associated with floating rate debt and refinancing of its long-term debt. Regulated interest rate variances from forecast for rate-setting purposes are recovered through future rates using a regulatory deferral account approved by the BCUC, while interest costs from variances in volumes of short-term borrowings from those forecast for rate-setting purposes are subject to sharing between customers and the Corporation. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Corporation's results of operations and financial position. In November 2023, the Department of Finance Canada tabled revised draft legislation to implement certain tax proposals that are intended to limit the deductibility of certain interest costs and financing expenses in computing income for tax purposes (the "EIFEL Proposals"). Legislation is expected to be enacted in 2024 with an effective date of January 1, 2024. The new legislation may adversely impact the amount of tax payable by the Corporation, which in turn could have an impact on customer rates.

Impact of Changes in Economic Conditions

A general and extended decline in BC's economy or in that of the Corporation's service area in particular, would be expected to have the effect of reducing demand for energy over time. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. New customer additions at the Corporation are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Corporation is

also affected by changes in trends in housing starts from single family dwellings to multi-family dwellings, for which the proportion that use natural gas for space and hot water heating is lower. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Corporation's service territories. The level of these activities can influence energy demand which could have a material adverse effect on the Corporation.

Counterparty Credit Risk

The Corporation is exposed to credit risk in the event of non-performance by counterparties. The Corporation deals with reasonable credit-quality institutions in accordance with established credit approval practices. To date the Corporation has not experienced any material counterparty defaults and does not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, can change rapidly. In the event of non-performance by counterparties, there could be a material adverse effect on the Corporation's results of operations and financial position.

Human Resources

The ability of the Corporation to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain skilled workforces. Competitive labour market conditions create challenges in attracting and retaining technical and professional staff. Like other utilities across Canada, the Corporation is also faced with demographic challenges relating to such skilled workforces. The inability to attract, develop and retain skilled workforces could have a material adverse effect on the Corporation.

Labour Relations

The Corporation employs members of labour unions that have entered into collective bargaining agreements with the Corporation. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Corporation. There can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed.

The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have a material adverse effect on the Corporation's results of operations and financial position.

Employee Future Benefits

The Corporation maintains defined benefit pension plans and supplemental pension arrangements. There is no certainty that the plan assets will be able to earn the assumed rate of returns. Market driven changes impacting the performance of the plan assets may result in material variations in actual return on plan assets from the assumed return on the assets causing material changes in net benefit costs. Net benefit cost is impacted by, among other things, the discount rate, changes in the expected mortality rates of plan members, the amortization of experience and actuarial gains or losses, and expected return on plan assets. Market driven changes impacting other assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in net benefit cost.

There is also measurement uncertainty associated with net benefit cost, future funding requirements, the net accrued benefit asset and projected benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

Net benefit cost variances from forecast for rate-setting purposes are recovered through future rates using regulatory deferral accounts approved by the BCUC. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Corporation's results of operations and financial position.

Information Technology Infrastructure

The ability of the Corporation to operate effectively is dependent upon managing and maintaining information systems and infrastructure that support the operation of distribution, transmission and storage facilities; provide customers with billing and consumption information; and support the financial and general operating aspects of the business. The reliability of the communication infrastructure and supporting systems are also necessary to provide important safety information. System failures, or failures in system implementations, could have a material adverse effect on the Corporation.

Cybersecurity

The Corporation operates critical energy infrastructure in its service territory and, as a result, is exposed to the risk of cybersecurity violations. Unauthorized access to corporate and information technology systems due to hacking, malware, ransomware, viruses and other causes which may become more sophisticated over time could result in service disruptions, system failures, misappropriated funds, corruption or unavailability of critical data, and disclosure of sensitive, confidential and proprietary business information. In addition, in the normal course of operation, the Corporation requires access to confidential customer data, including personal and credit information, which could be exposed in the event of a security breach. A cybersecurity breach could have a material adverse effect on the Corporation's results of operations and financial position, and there is no certainty whether any resulting uninsured monetary damages will be recoverable from customers.

Pandemics and Public Health Crises

The Corporation could be negatively impacted by a widespread outbreak of communicable disease or other public health crisis that causes economic and/or other disruptions. Should a public health crisis occur, the efforts to reduce the health impact on populations and control the spread of communicable disease could lead to measures that restrict travel, workplace occupancy, business operations, and a prolonged reduction in economic activity within the service territory. These measures could lead to potential impacts on the Corporation's operations that may include, but are not limited to, availability of personnel, energy usage and revenues, customer retention, the timing of capital expenditures, supply chain disruptions, the amount and timing of operating and maintenance expenses, application of regulatory deferral mechanisms, disruptions to capital markets leading to liquidity issues, and the collectability of receivables from customers that are affected by the economic impact of the pandemic. The overall impact would depend on the duration and severity of the pandemic, potential government actions to mitigate public health impacts or aid economic recovery, and other factors beyond the Corporation's control. An extended period of economic disruption resulting from a pandemic or other public health crisis could have a material adverse effect on the Corporation.

Certain of these potential impacts are expected to be mitigated through the use of regulatory deferral mechanisms, including those that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation, and allow for recovery through customer rates in subsequent years. The inability to recover these variances as currently allowed could have a material adverse effect on the Corporation's results of operations.

Continued Reporting in Accordance with US GAAP

In May 2022, the Corporation's principal regulator, the British Columbia Securities Commission ("BCSC") approved the extension of the Corporation's exemptive relief order which permits the Corporation to continue reporting in accordance with US GAAP, until the earliest of: (i) January 1, 2027; (ii) the first day of the Corporation's financial year that commences after the Corporation ceases to have rate-regulated activities; and (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for a Mandatory Rate-regulated Standard, and (b) two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard.

In January 2021, the IASB issued an Exposure Draft which is expected to result in a permanent mandatory standard specific to entities with activities subject to rate regulation. If BCSC relief does not continue as detailed above, the Corporation would then be required to become a United States Securities and Exchange Commission registrant in order to continue reporting under US GAAP, otherwise the Corporation would be required to adopt International Financial Reporting Standards ("IFRS") for external reporting purposes.

The Exposure Draft is currently being reviewed by the IASB against consultative feedback, and the timing of a standard based on the IASB Exposure Draft is not yet known. The ultimate impact of a requirement to adopt IFRS for external reporting purposes is not yet known.

Legal, Administrative and Other Proceedings

Legal, administrative and other proceedings arise in the ordinary course of business and may include environmental and climate-related claims, employment-related claims, marketing and advertising related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, claims regarding marketing and advertising practices, actions by regulatory or tax authorities, and other matters. There is no certainty any resulting judgments, settlements, or orders for monetary damages, fines or penalties will be recoverable from customers.

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 year ended December 31, 2023, there were no ASUs issued by FASB that have a material impact on these Consolidated Financial Statements.

Future Accounting Pronouncements

The following updates have been issued by FASB, but have not yet been adopted by the Corporation. 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 Consolidated Financial Statements.

Improvements to Income Tax Disclosures

ASU No. 2023-09, *Improvements to Income Tax Disclosures*, issued in December 2023, is effective for the Corporation January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. Principally, it requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. The Corporation is assessing the impact of adoption of this ASU on the disclosures to its consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's 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 involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in the period in which they become known. The Corporation's critical accounting estimates are discussed below.

Regulation

Generally, the accounting policies used by the Corporation in its regulated operations are subject to examination and approval by the regulatory authority, the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using US GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates 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. The final amounts approved by the regulatory authority for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event. As at December 31, 2023, the Corporation recognized $1,500 million in current and long-term regulatory assets (December 31, 2022 - $1,260 million) and $473 million in current and long-term regulatory liabilities (December 31, 2022 - $524 million).

Depreciation, Amortization and Removal Costs

Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2023, the Corporation's property, plant and equipment and intangible assets were $6,312 million, or approximately 68 per cent of total assets, compared to $5,965 million, or approximately 67 per cent of total assets, as at December 31, 2022. Changes in depreciation and amortization rates may have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As approved by the BCUC, the net salvage provision is collected as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

As part of the customer rate-setting process, appropriate depreciation, amortization and net salvage provision rates are approved by the BCUC for the Corporation's regulated operations. The rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, independent third-party depreciation studies are performed and based on the results of these studies, the impact of any over-or-under collection, as a result of actual experience differing from that expected and provided for in previous rates, is generally reflected in future rates and expenses.

Assessment for Impairment of Goodwill

The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill, and any impairment provision has to be charged to earnings. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value was below its carrying value. No such event or change in circumstances occurred during 2023.

As at December 31, 2023, goodwill totaled $913 million (December 31, 2022 - $913 million).

During 2023, the Corporation performed an annual assessment of goodwill and concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

Employee Future Benefits

The Corporation's defined benefit pension plans, supplemental pension arrangements, and OPEB plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the projected benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of determining pension net benefit cost for 2023, was 6.80 per cent, which is an increase from the 6.50 per cent that was assumed in 2022. As one of the Corporation's defined benefit pension plans has an excess interest indexing provision, where a portion of investment returns are allocated to provide for indexing of pension benefits, the projected benefit obligation for this plan may vary based on the expected long-term rate of return on plan assets.

The assumed discount rate, used to measure the projected pension benefit obligations on the measurement date of December 31, 2023, and to determine the pension net benefit cost for 2024, is 4.50 per cent. This is a decrease from the 5.25 per cent discount rate used to measure the projected benefit obligations as at December 31, 2022, and to determine the pension net benefit cost for 2023.

The long-term rate of return is based on the expected average return of the assets over a long period given the relative asset mix. The discount rate is determined with reference to the current market rate of interest on high quality debt instruments with cash flows that match the time and amount of expected benefit payments.

The Corporation expects net benefit cost for 2024 related to its defined benefit pension plans, prior to regulatory adjustments, to be $5 million, an increase of $5 million compared to 2023, which is primarily due to an increase in current service costs and amortization of actuarial gains, partially offset by an increase in the expected return on plan assets.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and discount rate on 2023 pension net benefit cost, and the related projected benefit obligations recognized in the Corporation's Consolidated Financial Statements:

Increase (Decrease) *($ millions)*	**Net Benefit Cost**	**Projected Benefit Obligation**
1% increase in the expected rate of return	**(7)**	**6**
1% decrease in the expected rate of return	**4**	**(40)**
1% increase in the discount rate	**(12)**	**(118)**
1% decrease in the discount rate	**7**	**136**

The above table reflects the changes before the effect of any regulatory deferral mechanism approved by the

BCUC. The Corporation currently has in place a BCUC approved mechanism to defer variations in pension net benefit costs from forecast net benefit costs, used to set customer rates, as a regulatory asset or liability.

Other significant assumptions applied in measuring the pension net benefit cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Corporation's OPEB plans are also subject to judgments utilized in the actuarial determination of the OPEB net benefit cost and related projected benefit obligation. Except for the assumption of the expected long-term rate of return on plan assets, the above assumptions, along with health care cost trends, were also utilized by management in determining OPEB plan net benefit cost and projected benefit obligation. The Corporation currently has in place a BCUC approved mechanism to defer variations in OPEB net benefit cost from forecast OPEB net benefit cost, used to set customer rates, as a regulatory asset or liability.

As at December 31, 2023, the Corporation had a pension projected benefit net liability of $78 million (December 31, 2022 - $7 million) and an OPEB projected benefit liability of $101 million (December 31, 2022 - $86 million). The increase in the projected pension benefit net liability during 2023 was primarily a result of the 0.75 per cent decrease in the discount rate used to measure the projected benefit liability, partially offset by a higher than expected return on plan assets. The increase in the OPEB projected benefit liability was also driven by the decrease in the discount rate. During 2023, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $15 million (2022 - $19 million).

Asset Retirement Obligations ("AROs")

AROs are legal obligations associated with the retirement of long-lived assets. A liability is recorded in the period in which the obligation can be reasonably estimated at the present value of the estimated fair value of the future costs. The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. The Corporation does not have any AROs for which amounts have been recorded as at December 31, 2023 and 2022.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the natural gas transmission and distribution systems are reasonably expected to operate in perpetuity due to the nature of their operation; and applicable licenses and permits are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licenses, permits, or agreements are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

Revenue Recognition

The Corporation recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings or estimates that establish natural gas consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated natural gas sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of natural gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled natural gas consumption will result in adjustments to natural gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2023 the amount of accrued unbilled revenue recorded in accounts receivable was $144 million (December 31, 2022 - $271 million) on annual natural gas revenues of $1,766 million (December 31, 2022 - $2,079 million).

Income Taxes

Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and

any related valuation allowance, might vary from actual amounts incurred.

FINANCIAL INSTRUMENTS

The Corporation has natural gas contracts subject to regulatory deferral, all of which are Level 2 of the fair value hierarchy. Under the hierarchy, fair value of Level 2 financial instruments is determined using pricing inputs that are observable in the marketplace.

Recurring Fair Value Measures

The following table presents the fair value of assets and liabilities that are accounted for at fair value on a recurring basis as at December 31. Contracts that are "in the money" are included in accounts receivable and other current assets or in long-term other assets, and "out of the money" are included in accounts payable and other current liabilities or in long-term other liabilities.

($ millions)	**2023**	2022
Assets		
Current	**3**	47
Long-term	**-**	
Total assets	**3**	47
Liabilities		
Current	**(81)**	(70)
Long-term	**(18)**	(37)
Total liabilities	**(99)**	(107)
Total liabilities, net	**(96)**	(60)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception.

FEI enters into physical natural gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. Swap contracts are agreements between two parties to exchange streams of payments over time according to specified terms. Swap contracts require receipt of payment for the notional quantity of the commodity based on the difference between a fixed price and the market price on the settlement date. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

Natural gas contracts held by FEI are subject to regulatory recovery through rates. As at December 31, 2023, natural gas contract derivatives are not designated as hedges and any unrealized losses and gains arising from changes in fair value of these contracts are 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)	**2023**	2022
Unrealized net loss recorded to current regulatory assets	**96**	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.

		December 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**	**3,244**	3,295	3,101

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth information derived from audited financial statements. These results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Years Ended December 31	2023	2022	2021
($ millions)			
Revenue	**1,937**	2,083	1,714
Net earnings attributable to controlling interest	**337**	227	182
Total assets	**9,236**	8,909	8,173
Long-term debt, excluding current portion	**3,274**	3,273	3,123
Dividends on common shares	**240**	170	165

2023/2022 – Revenue decreased $146 million and net earnings increased $110 million over 2022. The decrease in revenue was primarily due to a lower cost of natural gas recovered from customers, as approved by the BCUC, and an increase in the refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year, partially offset by an increase in revenue associated with regulatory deferrals, including the revenue deficiency deferral for 2023 established as a result of the GCOC Stage 1 Decision, an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, and an increase in gas mitigation incentive revenues. The increase in net earnings was primarily due to an increase in FEI's deemed equity component of capital structure from 38.5 per cent to 45 per cent, and an increase in allowed ROE from 8.75 per cent to 9.65 per cent, resulting from the GCOC Stage 1 Decision. The net impact of the change in cost of capital was $46 million. Net earnings for 2022 are based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent. In addition to the above, the increase was due to a $43 million higher income tax benefit as a result of the Corporation implementing a tax loss utilization plan ("TLUP") in 2023 for a larger investment amount than a TLUP implemented in 2022, a higher investment in regulated assets, and an increase in gas mitigation incentive revenue, which is retained by the utility, partially offset by lower favourable variances primarily attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2022. The increase in total assets was mainly due to investment in DSM and the Corporation's capital expenditure program, which included sustainment capital as well as major project expenditures, and an increase in regulatory assets, which include a $48 million regulatory asset recognized related to the revenue deficiency deferral for 2023 established as a result of the GCOC Stage 1 Decision. Long-term debt was consistent with 2022.

2022/2021 – Revenue increased $369 million and net earnings increased $45 million over 2021. The increase in revenue was primarily due to a higher cost of natural gas recovered from customers, as approved by the BCUC, and an increase in revenue approved for rate-setting purposes, resulting from a higher investment in regulated assets, partially offset by an increase in the recovery of the MCRA gas storage and transport cost regulatory liability, and a decrease in revenue associated with regulatory deferrals. The increase in net earnings was primarily due to a $27 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, 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. The increase in total assets was mainly due to investment in DSM and the Corporation's capital expenditure program, which included sustainment capital as well as major project expenditures, and an increase in accounts receivable and other current assets, which were primarily due to higher tariff-based trade receivables and higher gas cost mitigation receivables. The increase in long-term debt was due to the issuance of $150 million of unsecured MTN Debentures during the fourth quarter of 2022.

From 2021 to 2023, dividends were paid to assist in maintaining the BCUC approved capital structure. During 2023, as a result of the GCOC Stage 1 Decision discussed in the "Regulation" section of this MD&A, the approved deemed equity component of capital structure was updated from 38.5 per cent to 45 per cent, and the approved debt component of capital structure was updated from 61.5 per cent to 55 per cent, both effective as of January 1, 2023. In December 2023 FEI received a $300 million equity injection from the Corporation's parent company, FHI, to align with the new deemed equity component of capital structure as approved in the GCOC Stage 1 Decision.

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. In May 2023, Fortis announced FHI had entered into an agreement to sell its ownership of ACGS to an entity not related to Fortis, subject to required approvals and closing conditions. The transaction closed on November 1, 2023, after which ACGS ceased to be a related party to the Corporation. 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 years ended December 31 were as follows:

($ millions)	**2023**	2022
Other income received from FHI (a)	**259**	100
Operation and maintenance expense charged to FBC (b)	**9**	8
Operation and maintenance expense charged to FHI (c)	**1**	1
Operation and maintenance expense charged to ACGS (d)	**-**	1
Total related party recoveries	**269**	110

(a) The Corporation received dividend income from FHI relating to a $4,700 million (2022 - $3,000 million) investment in preferred shares as part of TLUP.

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

(c) The Corporation charged FHI for office rent, management services, and other labour.

(d) The Corporation charged ACGS for 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 years ended December 31 were as follows:

($ millions)	**2023**	2022
Finance charges paid to FHI (a)	**259**	100
Gas storage and purchases charged by ACGS (b)	**25**	37
Operation and maintenance expense charged by FHI (c)	**14**	13
Operation and maintenance expense charged by FBC (d)	**7**	7
Total related party costs	**305**	157

(a) FHI charged the Corporation interest on $4,700 million (2022 - $3,000 million) of intercompany subordinated debt as part of a TLUP.

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

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

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

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 as at December 31:

	2023		2022	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
ACGS	**-**	**-**	-	(4)
FHI	**-**	**-**	-	(2)
Fortis	**1**	**-**	-	-
FBC	**1**	**-**	-	-
Total due from (due to) related parties	**2**	**-**	-	(6)

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, expired on June 30, 2023 and is currently under negotiation. The second collective agreement, representing customer service employees was ratified during June 2023 and expires on March 31, 2027.

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.

Tax Legislation

During 2023, the Province of BC confirmed that current biomethane legislation does not allow for unsold biomethane acquired in previous months to be eligible for a carbon tax refund, which could cause the Corporation to fund the granting of a carbon tax credit to customers for a portion of future RNG sales. FEI awaits a government decision to amend biomethane legislation to recognize the concept of biomethane inventory, which may mitigate this potential future liability. Should the provincial government choose not to amend legislation, FEI has proposed amendments to its application with the BCUC with respect to its RNG Program to seek to balance its RNG supply and demand monthly. A BCUC decision on the amendments proposed by FEI is expected by the second quarter of 2024.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 391,628,651 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.sedarplus.ca. The information contained on, or accessible through, either of these websites is not incorporated by reference into this document.

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