FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS
For the Year Ended December 31, 2022

February 9, 2023

The following FortisBC Energy Inc. ("FEI" or the "Corporation") Management Discussion & Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. Financial information for 2022 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, 2022 and 2021, prepared in accordance with US GAAP.

In this MD&A, FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., FAES refers to FortisBC Alternative Energy Services Inc., ACGS refers to Aitken Creek Gas Storage ULC, and Fortis refers to the Corporation's ultimate parent, Fortis Inc.

FORWARD-LOOKING STATEMENT

Certain statements in this MD&A contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes, but is not limited to, statements regarding the Corporation's 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; certain conditions of Woodfibre LNG Limited ("Woodfibre LNG") and on FEI receiving the remaining regulatory and permitting approvals associated with the pipeline expansion to the proposed Eagle Mountain Woodfibre Liquefied Natural Gas site; and the Corporation's estimated contractual obligations.

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

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); natural gas competitiveness risk; commodity price risk; climate change risk; weather and natural disasters risk; environment, health and safety matters risk; natural gas supply risk; asset breakdown, operation, maintenance and expansion risk; permits risk; risks related to Indigenous rights and engagement; underinsured and uninsured losses; capital resources and liquidity risk; interest rates risk; impact of changes in economic conditions risk; counterparty credit risk; human resources risk; labour relations risk; employee future benefits risk; information technology infrastructure risk; cybersecurity risk; pandemic and public health crises risk;

continued reporting in accordance with US GAAP risk; legal, administrative and other proceedings risk; and other risks described in the Corporation's most recent Annual Information Form ("AIF"). For additional information with respect to these risk factors, reference should be made to the "Business Risk Management" section of 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 1,075,600 residential, commercial, industrial, and transportation customers through approximately 51,200 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers, and obtains natural gas and renewable gas supplies on behalf of most residential, commercial, and industrial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

The Corporation is regulated by the 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

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

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

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

In December 2021, the BCUC approved a January 1, 2022, delivery rate increase of 8.07 per cent over 2021 rates. This delivery rate increase includes a 2022 forecast average rate base of $5,409 million.

In December 2022, the BCUC approved a delivery rate increase of 7.69 per cent over 2022 rates, on an interim basis, effective January 1, 2023, pending the outcomes of Stage 1 of the BCUC's current Generic Cost of Capital Proceeding (the "GCOC Proceeding") and FEI's Application for Acceptance of 2023 Demand Side Management ("DSM") Expenditures proceeding. The interim rate increase includes a 2023 forecast average rate base of $5,943 million.

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 which are to be set at 5 per cent of the storage and transport costs for all other FEI customers. The delivery rate impact for residential customers in the Fort Nelson Service Area is to be phased in over five years starting January 1, 2023.

Allowed Return on Equity and Capital Structure

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

Customer Rates and Deferral Mechanisms

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

Variances from regulated forecasts used to set rates for natural gas revenue and cost of natural gas are flowed back to customers in future rates through approved regulatory deferral mechanisms and therefore these variances do not have an impact on net earnings for the years ended December 31, 2022 and 2021.

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 October 1, 2021, January 1, 2022, July 1, 2022 and, in December 2022, FEI received approval to decrease the commodity rate effective January 1, 2023. FEI also received approval to increase the storage and transport rate effective January 1, 2022 and, in December 2022, FEI received approval to increase the storage and transport rate effective 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.

Prior to 2017, the Provincial government allowed $170 million of FEI investment in incentives and infrastructure funding under the Greenhouse Gas Reductions Regulations ("GGRR") for FEI natural gas for transportation ("NGT") programs. During 2017, the Provincial government amended the GGRR, allowing an additional $160 million of FEI investment in incentives and infrastructure funding to further expand the FEI NGT programs, for a total of $330 million under the GGRR. Specifically, the additional incentives provide for the following to be included in FEI's regulated rate base, if certain conditions are met:

- incremental expenditures of $70 million toward incenting LNG powered marine and rail;
- incremental expenditures of $40 million toward incenting NGT customers that consumed natural gas procured from biomass or biogas sources; and
- investments of $50 million 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.

The $330 million in GGRR incentives explained above 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.

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.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year		
Periods ended December 31	**2022**	2021	Variance	**2022**	2021	Variance
Gas sales *(petajoules)*	**75**	74	1	**231**	228	3
($ millions)						
Revenue	**724**	590	134	**2,083**	1,714	369
Cost of natural gas	**416**	289	127	**1,055**	713	342
Operation and maintenance	**87**	85	2	**292**	284	8
Property and other taxes	**18**	17	1	**72**	71	1
Depreciation and amortization	**75**	70	5	**302**	285	17
Total expenses	**596**	461	135	**1,721**	1,353	368
Operating income	**128**	129	(1)	**362**	361	1
Add: Other income	**37**	4	33	**123**	12	111
Less: Finance charges	**68**	35	33	**246**	144	102
Earnings before income taxes	**97**	98	(1)	**239**	229	10
Income tax expense	**6**	20	(14)	**11**	46	(35)
Net earnings	**91**	78	13	**228**	183	45
Net earnings attributable to non-controlling interests	**-**	-	-	**1**	1	-
Net earnings attributable to controlling interest	**91**	78	13	**227**	182	45

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the quarter ended December 31, 2022 as compared to December 31, 2021:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**13**	Net earnings for the quarter ended December 31, 2022 were $91 million compared to $78 million for the same period in 2021. The higher net earnings were primarily due to: • an $8 million higher income tax benefit as a result of the Corporation implementing a tax loss utilization plan ("TLUP") in the second quarter of 2022 and winding-up the TLUP partway through the fourth quarter of 2022, where no similar TLUP was implemented in 2021, • a higher investment in regulated assets, • higher favourable regulated variances partially attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2021, 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. Both 2022 and 2021 net earnings are based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent.
Revenue	**134**	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 higher investment in regulated assets, partially offset by • an increase in the refund of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory liability, compared to the prior year recovery of the MCRA gas storage and transport cost regulatory asset, and • a decrease in revenue associated with regulatory deferrals. Gas sales volumes were higher than the same quarter in the previous year, primarily due to higher consumption by residential and commercial customers, primarily due to colder weather, partially offset by lower consumption by transportation customers. The variance between revenue associated with actual consumption and revenue forecasted for rate-setting purposes is captured either in the Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenue and other revenue, resulting in no impact on total revenue.
Cost of natural gas	**127**	The increase was primarily due to: • a higher commodity cost, as approved by the BCUC, of $5.907 per GJ for the fourth quarter of 2022, as compared to $3.844 per GJ effective for the fourth quarter of 2021, • a higher storage and transport cost, as approved by the BCUC, of $1.505 per GJ for 2022, as compared to $1.350 per GJ for 2021, and • an increase in total consumption of gas by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity, partially offset by • a refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year recovery of the MCRA gas storage and transport cost regulatory asset. 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 2022, volumes provided to customers under bundled services were higher compared to the same quarter in 2021 while volumes provided to customers that received only delivery service were lower compared to the same quarter in 2021. The higher volumes provided to customers under bundled services drove a higher cost of natural gas in the fourth quarter of 2022.

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Operation and maintenance	**2**	The increase was primarily due to higher costs, the variances of which are retained by the utility, as well as inflationary increases contributing to an overall increase in expenses, partially offset by the timing of incurring operating costs and a lower service cost component of pension and other post-employment benefits expense ("OPEB").
Depreciation and amortization	**5**	The increase was primarily due to higher amortization of regulatory assets, as well as a higher depreciable asset base compared to the same period in 2021.
Other income	**33**	Other income primarily consists of dividend income from TLUP structures, the equity component of allowance for funds used during construction ("AFUDC"), and the non-service cost component of pension and OPEB. As part of the TLUP implemented in 2022, the Corporation received dividend income from FHI relating to a $3,000 million investment in preferred shares. The increase was primarily due to higher dividend income due to FEI having a TLUP in place from the second quarter of 2022 until partway through the fourth quarter of 2022, where no similar TLUP was implemented in 2021, an increase in the non-service cost component of pension and OPEB, and a higher equity component of AFUDC in 2022.
Finance charges	**33**	The increase was primarily due to FEI having a TLUP in place since the second quarter of 2022 until partway through the fourth quarter of 2022, where no similar TLUP was implemented in 2021.
Income tax expense	**(14)**	The decrease was primarily due to a higher TLUP tax recovery and higher deductible temporary differences associated with property, plant and equipment.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the year ended December 31, 2022 as compared to December 31, 2021:

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**45**	For the year ended December 31, 2022, net earnings were $227 million compared to $182 million for the same period in 2021. The increase 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 and winding-up the TLUP partway through the fourth 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, as compared to the same period in 2021, 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.
Revenue	**369**	The increase in revenue was primarily due to the same reasons as identified in the quarter. For the year ended December 31, 2022, gas sales volumes were higher compared to 2021 primarily due to the same reasons as identified in the quarter.
Cost of natural gas	**342**	The increase was primarily due to: • a higher commodity cost, as approved by the BCUC, of $4.503 per GJ for the first six months of 2022, and $5.907 GJ for the remainder of 2022, as compared to $2.844 per GJ for the first nine months of 2021 and $3.844 per GJ for the fourth quarter of 2021, • a higher storage and transport cost, as approved by the BCUC, of $1.505 per GJ for 2022, as compared to $1.350 per GJ for 2021, and

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
		• an increase in total consumption of gas by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity, partially offset by • a refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year recovery of the MCRA gas storage and transport cost regulatory asset.
Operation and maintenance	**8**	The increase was primarily due to higher costs, the variances of which are retained by the utility, as well as inflationary increases contributing to an overall increase in expenses, partially offset by a lower service cost component of pension and OPEB expense.
Depreciation and amortization	**17**	The increase was primarily due to the same reasons as identified in the quarter.
Other income	**111**	The increase was primarily due to the same reasons as identified in the quarter.
Finance charges	**102**	The increase was primarily due to the same reasons as identified in the quarter.
Income tax expense	**(35)**	The decrease was primarily due to the same reasons as identified in the quarter, partially offset by higher earnings before income tax.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2021 through December 31, 2022. 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, 2022	724	91
September 30, 2022	269	(7)
June 30, 2022	396	25
March 31, 2022	694	118
December 31, 2021	590	78
September 30, 2021	222	(20)
June 30, 2021	316	14
March 31, 2021	586	110

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

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

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

March 2022/2021 – Net earnings were higher primarily due to higher investment in regulated assets as well as lower 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, 2022 and December 31, 2021:

Balance Sheet Account	**Increase (Decrease)** *($ millions)*	**Explanation**
Cash	**39**	The increase was primarily due to the receipt of a cash deposit relating to the development expenditures to be incurred for the EGP project, and the timing of draws on the credit facility as compared to payment of certain invoices.
Accounts receivable and other current assets, net	**236**	The increase was primarily due to: • higher tariff-based trade receivables, primarily as a result of an increase in customer rates, customer additions, and increased consumption due to colder weather in the fourth quarter of 2022 as compared to the fourth quarter of 2021, • higher gas cost mitigation receivables, • a change in the fair value of natural gas derivatives, and • higher cash collateral paid for natural gas contracts.
Inventories	**47**	The increase was primarily due to a higher weighted average cost of natural gas in storage and higher volumes of natural gas in storage.
Regulatory assets (current and long-term)	**47**	The increase was primarily due to: • the change in fair market value of natural gas derivatives, • an increase in DSM expenditures, • an increase in the biomethane variance account due to costs incurred to acquire biomethane gas exceeding those costs recovered in customer rates, • an increase in the variance between actual pension costs and those approved for recovery in rates, and • a higher Commodity Cost Reconciliation Account regulatory asset due to commodity costs exceeding those costs recovered in customer rates, partially offset by • an increase in unrecognized actuarial gains for pension and OPEB, the offset of which moved from a regulatory asset position as at December 31, 2021 to a regulatory liability position as at December 31, 2022.
Property, plant and equipment, net	**359**	The increase was primarily due to capital expenditures of $573 million, $13 million in equity AFUDC, and $1 million of project development costs which were transferred from regulatory assets to capital projects in 2022, less: • depreciation expense, excluding net salvage provision, of $189 million, • costs of removal of $19 million incurred, which is included as part of the net salvage provision in regulatory liabilities, • contributions in aid of construction ("CIAC") of $15 million, and • changes in accrued capital expenditures of $5 million.
Credit facilities	**(39)**	The decrease was primarily a result of net repayments with proceeds from the issuance of $150 million in unsecured Medium Term Note ("MTN") Debentures during the fourth quarter of 2022, partially offset by borrowings used to fund working capital.
Accounts payable and other current liabilities	**258**	The increase was primarily due to: • a change in the fair value of natural gas derivatives, • higher cash deposits held relating to development expenditures incurred for the EGP project, • higher income tax payable,

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
		• higher gas cost payables, as a result of higher volume and cost of gas purchased, • higher accrued capital expenditures, and • higher carbon tax payable, as a result of higher volumes sold and a higher carbon tax rate.
Regulatory liabilities (current and long-term)	**288**	The increase was primarily due to: • a higher MCRA regulatory liability due to higher mitigation activities and amounts collected in customer rates exceeding the midstream costs incurred, • recognition of actuarial gains for pension and OPEB, the offset of which was deferred as a regulatory liability, • a higher RSAM regulatory liability due to variances in gas use for residential and commercial customers, • an increase in the net salvage provision, and • an increase in the emissions regulations deferral account due to the sale of carbon credits generated under the BC Low Carbon Fuel Standard, which will be refunded to customers through delivery rates in 2023.
Long-term debt	**150**	The increase was due to the issuance of $150 million of unsecured MTN Debentures during the fourth quarter of 2022, net of debt issuance costs. The proceeds were used to finance or refinance eligible projects under FEI's Green Bond Framework.
Other liabilities (long-term)	**(119)**	The decrease was primarily due to a decrease in the unfunded status of the Corporation's defined benefit pension and OPEB plans, which was primarily driven by an increase in the discount rate used to measure the projected benefit obligation, partially offset by a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**150**	The increase was due to a $150 million FEI equity issuance during the first quarter of 2022, the proceeds of which were used to repay credit facilities in support of the equity component of FEI's capital expenditure program.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements and Liquidity

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

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

The Corporation's ability to service its debt obligations and pay dividends on its common shares is dependent on the financial results of the Corporation. Depending on the timing of cash payments, borrowings under the Corporation's credit facility may be required from time to time to support the servicing of working capital deficiencies and payment of dividends. The Corporation may have to rely upon the proceeds of new debenture issuances to meet its principal debt obligations when they become due.

Summary of Consolidated Cash Flows

Years Ended December 31	2022	2021	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**612**	515	97
Investing activities	**(659)**	(550)	(109)
Financing activities	**86**	30	56
Net change in cash	**39**	(5)	44

Operating Activities

Cash from operating activities was $97 million higher compared to the same period in 2021 primarily due to higher net earnings after non-cash adjustments and changes in regulatory assets and liabilities, partially offset by changes in working capital that were driven primarily by changes in accounts receivable.

Investing Activities

Cash used in investing activities was $109 million higher compared to the same period in 2021 primarily due to higher capital expenditures.

Financing Activities

Cash from financing activities was $56 million higher compared to the same period in 2021. During 2022, net proceeds from a $150 million debenture issuance and a $150 million issuance of common shares were used for repayments on the credit facility, compared to the same period in 2021 where net proceeds from a $150 million debenture issuance and a $100 million issuance of common shares were used for repayments on the credit facility and to make termination payments on FEI's lease-in, lease-out arrangements.

During 2022, FEI paid common share dividends of $170 million (2021 - $165 million) to its parent company, FHI.

Contractual Obligations

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

As at December 31, 2022	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)							
Long-term debt [1]	**3,295**	**-**	**-**	**-**	**150**	**-**	**3,145**
Interest obligations on long-term debt	**2,647**	**152**	**152**	**152**	**150**	**148**	**1,893**
Gas purchase obligations (a)	**4,791**	**757**	**368**	**346**	**296**	**260**	**2,764**
Other (b)	**25**	**18**	**4**	**2**	**1**	**-**	**-**
Total	**10,758**	**927**	**524**	**500**	**597**	**408**	**7,802**

[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, 2022.

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 addition to the items in the table above, the Corporation has issued commitment letters to customers who may meet the criteria to obtain energy efficiency funding under the DSM Expenditures Plan approved by the BCUC. As at December 31, 2022, the Corporation had issued $14 million (December 31, 2021 - $16 million) of commitment letters to these customers.

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, 2022, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $54 million (December 31, 2021 - $42 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 at 38.5 per cent equity and 61.5 per cent debt. 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 2016 decision on FEI's application to review the benchmark utility ROE and common equity component of capital structure, 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. The BCUC is currently reviewing the cost of capital for regulated utilities in BC through a GCOC Proceeding, which could affect FEI's capital structure and allowed ROE.

Credit Ratings

Debentures issued by the Corporation are rated by DBRS Morningstar 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**
DBRS Morningstar	A	Unsecured Debentures	Stable
Moody's	A3	Unsecured Debentures	Stable

During 2022, Moody's issued an updated credit rating report and, in January 2023, DBRS Morningstar issued an updated credit rating report, both confirming the Corporation's debenture rating and outlook.

Credit Facilities and Debentures

Credit Facilities

As at December 31, 2022, the Corporation had a $700 million syndicated operating credit facility in place, which matures in July 2027, and a $55 million uncommitted letter of credit facility in place which matures in March 2024.

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

($ millions)	**2022**	2021
Operating credit facility	**700**	700
Letter of credit facility	**55**	55
Draws on operating credit facility	**(203)**	(242)
Letters of credit outstanding	**(54)**	(42)
Credit facilities available	**498**	471

In December 2022, FEI executed an amendment to its operating credit facility to incorporate a Sustainability Linked Loan ("SLL") component. The SLL will incorporate sustainability performance targets considering avoided emissions from renewable gas and capital project opportunities with Indigenous participation. The amendment to the credit facility has been approved by the BCUC.

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.

On November 23, 2022, FEI entered into an agreement to issue $150 million of MTN Debentures Series 35. The issuance is the second under FEI's Green Bond Framework, the first of which was in 2020. Net proceeds have been used to finance or refinance eligible projects under FEI's Green Bond Framework and were primarily allocated to energy efficiency, pollution prevention and control, and RNG categories. The MTN Debentures bear interest at a rate of 4.67 per cent to be paid semi-annually and mature on November 28, 2052. The closing of the issuance occurred on November 28, 2022.

As at December 31, 2022, $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. In 2022, none of these restrictions constrained the distribution of FEI earnings not otherwise needed for reinvestment.

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 2023 projected capital expenditures are approximately $536 million, inclusive of AFUDC and excluding customer CIAC, and are necessary to provide service, public and employee safety, and reliability of supply of natural gas to the Corporation's customer base. In addition to the rate base amounts approved in annual regulatory decisions, multi-year projects under construction earn a regulated return. The 2022 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")

In December 2018, FEI filed a CPCN application, in the amount of approximately $220 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 continue throughout 2023.

Pattullo Gas Line Replacement ("PGR")

In August 2020, FEI filed a CPCN application, in the amount of approximately $175 million to be incurred primarily between 2021 and 2023, to replace the distribution system capacity currently provided by FEI's distribution gas line affixed on the Pattullo Bridge, which must be decommissioned in 2023 prior to the demolition of the Pattullo Bridge by the Province. The CPCN application was approved by the BCUC in June 2021, and construction will complete in 2023.

Okanagan Capacity Upgrade ("OCU")

In November 2020, FEI filed a CPCN application, in the amount of approximately $200 million to be incurred primarily between 2023 and 2024 if approved, 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.

Tilbury LNG Storage Expansion ("TLSE")

In December 2020, FEI filed a CPCN application, in the amount of approximately $530 million and expected to begin during 2023 if approved, to replace the original Tilbury Base Plant with a new storage tank, as well as regasification capacity. The TLSE project is also subject to various Environmental Assessment processes requiring approval. The TLSE project will 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. The regulatory process is complete, with a decision expected by mid-2023.

Advanced Metering Infrastructure ("AMI") Project

In May 2021, FEI filed a CPCN application, in the amount of approximately $400 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 regulatory process is complete, with a decision expected in the first quarter of 2023.

Transmission Integrity Management Capabilities ("TIMC")

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 regulatory process for this component is underway, with a decision expected in the last half of 2023.

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 Tilbury Phase 1A Expansion Project. 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 2023, FEI will continue to proceed with its pre-Front-End Engineering Design ("FEED") and FEED studies.

Other Capital Projects

In addition to the above, beyond 2023 the Corporation continues to pursue additional LNG infrastructure investment opportunities in BC, including the EGP gas line expansion to the proposed Woodfibre LNG site near Squamish, BC, and 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 the EGP pipeline expansion to the Woodfibre LNG site and for certain further expansions at the Tilbury site, subject to certain conditions.

With respect to FEI's potential EGP gas line expansion, the anticipated capital expenditures, net of the forecasted customer contribution, are $420 million. The current estimate of FEI's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of the customer contribution amount. FEI and Woodfibre LNG have entered into a pre-execution work agreement that establishes the funding requirements to be provided by Woodfibre LNG for FEI to incur ongoing project feasibility and development costs prior to construction. In April 2022, Woodfibre LNG issued a Notice to Proceed to its prime contractor for the proposed LNG site in Squamish, BC, and in July 2022, Woodfibre LNG's parent company announced a partner to jointly invest in the construction and operation of Woodfibre LNG, however FEI's project remains contingent on certain conditions of Woodfibre LNG and on FEI receiving the remaining regulatory and permitting approvals.

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 July 2022, FEI filed a DSM Expenditures Plan to invest approximately $141 million in 2023 and include such expenditures as rate base additions. The regulatory process is complete, with a decision expected in the first quarter of 2023.

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 rates 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. Fair regulatory treatment that allows the Corporation a reasonable opportunity to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as on-going capital attraction and growth. 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 expected or fair rate of return. The BCUC is reviewing the cost of capital for regulated utilities in BC through a GCOC Proceeding, which could affect FEI's capital structure and allowed ROE. The results of the GCOC Proceeding 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. There can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the expected rate of return.

A failure to obtain rates that recover the costs of providing service, or provide a reasonable opportunity to earn an appropriate ROE and capital structure as applied for, 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 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.

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; however, these supply costs are significantly higher than conventional natural gas, which could impact cost competitiveness in the short-term relative to electricity.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock, 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 franchise agreements, permits, building codes and zoning bylaws 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 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. 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 “Competitiveness and Commodity Price Risk”, 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 which includes 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.

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 DSM 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, forest fire, 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.

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 *Oil and Gas 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 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.

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 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 Rates

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 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.

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 natural gas has a lower penetration rate. 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 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, viruses and other causes could result in service disruptions and system failures. 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 security breach could have a material adverse effect on the Corporation's results of operations and financial position.

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. The nature of the Corporation's regulatory deferral mechanisms allow for recovery through customer rates in subsequent years.

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").

The ultimate timing and impact of a standard based on the IASB Exposure Draft 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, 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, 2022, there were no ASUs issued by FASB that have a material impact on these Consolidated Financial Statements.

Future Accounting Pronouncements

Any ASUs issued by FASB that are not included in this MD&A were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on these 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, 2022, the Corporation recognized $1,260 million in current and long-term regulatory assets (December 31, 2021 - $1,213 million) and $524 million in current and long-term regulatory liabilities (December 31, 2021 - $236 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, 2022, the Corporation's property, plant and equipment and intangible assets were $5,965 million, or approximately 67 per cent of total assets, compared to $5,603 million, or approximately 69 per cent of total assets, as at December 31, 2021. 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 2022.

As at December 31, 2022, goodwill totaled $913 million (December 31, 2021 - $913 million).

During 2022, 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 2022, was 6.50 per cent, which is an increase from the 5.70 per cent that was assumed in 2021. 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, 2022, and to determine the pension net benefit cost for 2023, is 5.25 per cent. This is an increase from the 3.00 per cent discount rate used to measure the projected benefit obligations as at December 31, 2021, and to determine the pension net benefit cost for 2022.

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 2023 related to its defined benefit pension plans, prior to regulatory adjustments, to be $nil, a decrease of $21 million compared to 2022, which is primarily due to a decrease in current service costs and amortization of actuarial gains, partially offset by an increase in interest costs, which are driven by the increased discount rate, and 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 2022 net benefit pension 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	**(6)**	**13**
1% decrease in the expected rate of return	**-**	**(35)**
1% increase in the discount rate	**(10)**	**(100)**
1% decrease in the discount rate	**21**	**116**

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, 2022, the Corporation had a pension projected benefit net liability of $7 million (December 31, 2021 - $129 million) and an OPEB projected benefit liability of $86 million (December 31, 2021 - $120 million). The decrease in the projected pension benefit net liability during 2022 was primarily a result of the 2.25 per cent increase in the discount rate used to measure the projected benefit liability, partially offset by a lower than expected return on plan assets. The decrease in the OPEB projected benefit liability was also driven by the increase in the discount rate. During 2022, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $19 million (2021 - $32 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, 2022 and 2021.

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, 2022 the amount of accrued unbilled revenue recorded in accounts receivable was $271 million (December 31, 2021 - $200 million) on annual natural gas revenues of $2,079 million (December 31, 2021 - $1,645 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)	**2022**	2021
Assets		
Current	**47**	4
Total assets	**47**	4
Liabilities		
Current	**(70)**	(4)
Long-term	**(37)**	-
Total liabilities	**(107)**	(4)
Total liabilities, net	**(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, 2022, 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)	**2022**	2021
Unrealized net loss recorded to current regulatory assets	**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, 2022		December 31, 2021	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,295**	**3,101**	3,145	3,817

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	**2022**	2021	2020
($ millions)			
Revenue	**2,083**	1,714	1,385
Net earnings attributable to controlling interest	**227**	182	188
Total assets	**8,909**	8,173	7,738
Long-term debt, excluding current portion	**3,273**	3,123	2,973
Dividends on common shares	**170**	165	160

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 discussed further under "Projected Capital 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.

2021/2020 – Revenue increased $329 million and net earnings decreased $6 million over 2020. The increase in revenue was primarily due to a higher cost of natural gas recovered from customers, as approved by the BCUC, an increase in revenue approved for rate-setting purposes resulting from a higher investment in regulated assets, an increase in the recovery of the MCRA gas storage and transport cost regulatory asset compared to the prior year refund of the MCRA gas storage and transport cost regulatory liability, and an increase in revenue associated with regulatory deferrals. The decrease in net earnings was primarily due to a lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2020, where no similar TLUP was implemented in 2021, and the recognition of a non-recurring income tax recovery not subject to rate-setting in 2020, partially offset by a higher investment in regulated assets. The increase in total assets was mainly due to investment in DSM and the Corporation's capital expenditure program. The increase in long-term debt was due to the issuance of $150 million of unsecured MTN Debentures during the second quarter of 2021.

From 2020 to 2022, dividends were paid to assist in maintaining the BCUC approved capital structure of 38.5 per cent equity.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FBC and ACGS, in financing transactions and to provide or receive services and materials. The following transactions were measured at the exchange 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)	**2022**	2021
Other income received from FHI (a)	**100**	-
Operation and maintenance expense charged to FBC (b)	**8**	7
Operation and maintenance expense charged to FHI (c)	**1**	1
Operation and maintenance expense charged to ACGS (d)	**1**	1
Total related party recoveries	**110**	9

(a) The Corporation received dividend income from FHI relating to a $3,000 million (2021 - $nil) investment in preferred shares, as part of TLUP implemented in the second quarter of 2022.

(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)	**2022**	2021
Finance charges paid to FHI (a)	**100**	-
Gas storage and purchases charged by ACGS (b)	**37**	38
Operation and maintenance expense charged by FHI (c)	**13**	12
Operation and maintenance expense charged by FBC (d)	**7**	6
Total related party costs	**157**	56

(a) FHI charged the Corporation interest on $3,000 million (2021 - $nil) of intercompany subordinated debt, as part of a TLUP implemented in the second quarter of 2022.

(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:

	2022		2021	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
ACGS	**-**	**(4)**	-	(5)
FHI	**-**	**(2)**	-	(2)
FBC	**-**	**-**	1	**-**
Total (due to) due from related parties	**-**	**(6)**	1	(7)

OTHER DEVELOPMENTS

Collective Agreements

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

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

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 357,212,009 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

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

For further information, please contact:

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