FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Year Ended December 31, 2025

February 11, 2026

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 2025 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 years ended December 31, 2025 and 2024, 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., 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. Any capitalized terms in this Forward-Looking Statement section that are not otherwise defined in this section are as defined in this MD&A.

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 the potential impact of new or revised tariffs on forecast and actual capital expenditures, and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI, and debenture issuances; the Corporation's estimated contractual obligations; the expected construction start or substantial completion dates for the various projects described in this MD&A; the expectation that the BCUC will issue its decision in FBC and FEI's application for their joint ERP Modernization Project and FBC's CIS Replacement Project in mid-2026; expected expenditures as rate base additions resulting from the Corporation's Demand-Side Management ("DSM") Expenditures Plan including the timing of such expenditures; statements that the immediate impact of the Global Minimum Tax Act ("GMTA") may be mitigated by transitional safe harbours provided under the GMTA; and the expectation that any applicable Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB") that are not mentioned in this MD&A will not have a material impact on the Corporation's Consolidated Financial Statements.

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 significant climate change impacts; absence of adverse weather conditions and natural disasters; absence of environmental, health and safety issues; the ability to maintain, replace or expand the Corporation's assets at a cost that is not impacted by the potential of new or revised tariffs; the availability of natural gas supply; the ability to obtain and maintain applicable permits; that the Indigenous engagement process will not delay or otherwise impact the

Corporation's ability to obtain government or regulatory approvals; the adequacy of the Corporation's existing insurance arrangements; the ability to arrange sufficient and cost effective financing (including absence of adverse rating actions by credit rating agencies); absence of significant interest costs; continued energy demand, population growth and new housing starts; the absence of significant counterparty credit issues resulting in non-performance by counterparties; 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 significant information technology infrastructure failure; absence of cybersecurity failure; absence of pandemic and public health crises impacts; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to 2027 or earlier; and the absence of damages, fines, or penalties arising from legal, administrative and other proceedings.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); natural gas competitiveness risk; commodity price risk; climate change risk; weather and natural disasters risk; environment, health and safety matters risk; asset breakdown, operation, maintenance and expansion risk; natural gas supply risk; permits risk; risks related to Indigenous rights and engagement; underinsured and uninsured losses; capital resources and liquidity risk; interest costs risk; impact of changes in economic conditions risk; counterparty credit risk; human resources risk; labour relations risk; employee future benefits risk; information technology infrastructure risk; cybersecurity risk; pandemic and public health crises risk; continued reporting in accordance with US GAAP risk; legal, administrative and other proceedings risk; and other risks described in the Corporation's most recent Annual Information Form ("AIF"). For additional information with respect to these risk factors, reference should be made to the "Business Risk Management" section of this MD&A and to the Corporation's most recent AIF.

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 1,104,500 residential, commercial, industrial, and transportation customers through approximately 51,870 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers, and obtains natural gas and Renewable Natural Gas ("RNG") 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

Rate Framework for 2025 to 2027 ("Rate Framework")

In March 2025, the BCUC issued its decision on FEI and FBC's application requesting approval of a Rate Framework for the years 2025 to 2027. The Rate Framework builds upon the 2020-2024 Multi-Year Rate Plan ("MRP") and for FEI includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised 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 and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in technology, an updated set of service quality indicators designed to ensure the Corporation maintains service levels, and a continued 50/50 sharing between customers and the Corporation of variances from the allowed return on equity ("ROE"). The Rate Framework also includes a continuation of the main deferral mechanisms that were in place under the MRP.

In November 2024, the BCUC approved a 2025 delivery rate increase of 7.75 percent over 2024 rates, on an interim and refundable basis, and a 2025 forecast average rate base of $6,470 million. In July 2025, FEI filed updated annual review materials for 2025, requesting to set the 2025 delivery rate increase of 7.75 percent as permanent, an updated 2025 forecast average rate base of $6,452 million, and deferral of the 2025 revenue deficiency. The filing also included a request for a 2026 delivery rate increase of 10.07 percent over 2025 rates, and a 2026 forecast average rate base of $6,835 million. The application was approved by the BCUC in December 2025.

Recovery of Equity Issuance Costs

As part of the Stage 1 Generic Cost of Capital ("GCOC") Decision received in September 2023, the BCUC accepted that any reasonable and prudently incurred costs of issuing equity can be considered for recovery, over and above the approved costs of capital. In December 2024, FEI and FBC submitted an application outlining a methodology to determine the actual incurred equity issuance costs, to recognize those costs in a deferral account, and to collect those costs from customers through a future rate-setting process. The application was approved by the BCUC in June 2025. The deferral account, and the proposed period of recovery, of costs attributable to equity injections going back to January 1, 2023 were included in the updated annual review materials for 2025 included in the 2026 annual review filing, and have been approved for collection through customer rates over five years, beginning January 1, 2026.

Price Risk Mitigation

In June 2023, the BCUC approved FEI's Price Risk Mitigation Application to implement fixed price financial derivatives as a strategy to limit the exposure to fluctuations in natural gas prices for customers who receive commodity supply from FEI. This approval allows the enhanced use of financial derivative instruments for up to a certain amount of FEI's annual baseload commodity portfolio, for the term beginning in April 2024 and ending March 2028. The settlement of these transactions are captured in the Commodity Cost Reconciliation Account ("CCRA").

Customer Rates and Deferral Mechanisms

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

Variances from regulated forecasts used to set rates for natural gas revenue and cost of natural gas are flowed back to customers in future rates through approved regulatory deferral mechanisms and therefore these variances do not have an impact on net earnings for the years ended December 31, 2025 and 2024.

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 has received approval to maintain the same commodity rate each quarter since January 1, 2024. That commodity rate was also approved to be maintained effective October 1, 2025. FEI received approval to increase the storage and transport rate effective January 1, 2025.

As part of the MRP for the years 2020 to 2024, and the Rate Framework for the years 2025 to 2027, the BCUC has approved certain regulatory deferral mechanisms, including those that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation. These deferral mechanisms capture variances from regulated forecasts and flow them through customer rates in subsequent years. Variances from the allowed ROE, including most components of operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, are shared.

Directions to the BCUC

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

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

During 2017, the Provincial government amended the Greenhouse Gas Reductions Regulations ("GGRR") to allow specified amounts of FEI investment in infrastructure and incentive funding to further expand the FEI natural gas for transportation ("NGT") programs, for a total of $330 million. Specifically, incentives toward LNG powered marine and rail, incentives toward NGT customers that consume natural gas procured from biomass or biogas sources, and investments in related LNG bunkering infrastructure and assets required to enable the development of LNG bunkering capability to fuel LNG powered marine vessels calling at ports in BC, were allowed under the amended GGRR to be included in FEI's regulated rate base, if certain conditions are met. In addition, in the same GGRR amendment, the Provincial government authorized the utility to acquire RNG of up to 5 percent 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 RNG FEI can acquire from 5 percent to 15 percent 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 RNG to $31 per GJ, indexed to inflation.

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

FEI's opportunities under the GGRR and future successive legislation to further expand its investments in LNG for domestic use, as well as expand its investment into and supply of RNG, 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	**2025**	2024	Variance	**2025**	2024	Variance
Gas sales *(petajoules)*	**65**	67	(2)	**217**	220	(3)
($ millions)						
Revenue	**571**	517	54	**1,854**	1,646	208
Cost of natural gas	**170**	137	33	**544**	419	125
Operation and maintenance	**108**	96	12	**351**	322	29
Property and other taxes	**26**	23	3	**91**	89	2
Depreciation and amortization	**91**	85	6	**365**	337	28
Total expenses	**395**	341	54	**1,351**	1,167	184
Operating income	**176**	176	-	**503**	479	24
Add: Other income	**17**	14	3	**53**	44	9
Less: Finance charges	**38**	38	-	**153**	156	(3)
Earnings before income taxes	**155**	152	3	**403**	367	36
Income tax expense	**23**	34	(11)	**73**	81	(8)
Net earnings	**132**	118	14	**330**	286	44
Net earnings attributable to non-controlling interests	-	-	-	**1**	1	-
Net earnings attributable to controlling interest	**132**	118	14	**329**	285	44

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the quarter ended December 31, 2025 as compared to December 31, 2024:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**14**	Net earnings attributable to controlling interest for the quarter ended December 31, 2025 were $132 million compared to $118 million in net earnings attributable to controlling interest for the same period in 2024. The increase was primarily due to: • a higher investment in regulated assets, inclusive of the equity component of allowance for funds used during construction ("AFUDC") on FEI's investment in the EGP Project, which didn't reach $400 million until part way through the fourth quarter of 2024 as described in the "Projected Capital Expenditures" section of this MD&A, partially offset by • lower favourable regulated variances, primarily attributable to operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2024. Both 2025 and 2024 net earnings are based on an allowed ROE of 9.65 percent and a deemed equity component of capital structure of 45 percent.
Revenue	**54**	The increase was primarily due to: • an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, • a decrease in the refund of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior period, and • an increase in revenue related to the amortization of prior year alternative revenue flow-through deferrals, partially offset by • a decrease in revenue associated with regulatory deferrals, and • a lower cost of natural gas recovered from customers, as approved by the BCUC. Gas sales volumes were lower than the same quarter in the previous year due to lower consumption by residential, commercial and transportation customers, partially offset by higher consumption by LNG customers. Variances between revenue associated with actual consumption and revenue forecasted for rate-setting purposes are captured either in the Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenue and other revenue, resulting in no net impact on total revenue compared to what is approved in rates in the current year.

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Cost of natural gas	**33**	The increase was primarily due to: • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior year, and • a higher storage and transport cost, approved by the BCUC, of $1.260 per GJ for the fourth quarter of 2025, as compared to $1.102 per GJ for the fourth quarter of 2024, partially offset by • a decrease in total consumption by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity. 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 2025, volumes provided to customers under bundled services and customers that received only delivery service were both lower compared to the same quarter in 2024. Although total sales volumes were lower, only the lower volumes provided to customers under bundled services drove a lower cost of natural gas in the fourth quarter of 2025.
Operation and maintenance	**12**	The increase was primarily due to inflationary increases, the timing of incurring operating costs that are shared with or flowed through to customers, which includes a higher service cost component of pension and other post-employment benefit ("OPEB") expense, and higher regulated operating costs.
Depreciation and amortization	**6**	The increase was primarily due to higher amortization of regulatory assets and a higher depreciable asset base compared to 2024, partially offset by a decrease in the average depreciation rate applicable to the asset base, as approved in the Rate Framework Decision.
Income tax expense	**(11)**	The decrease was primarily due higher deductible temporary differences associated with property, plant and equipment, and lower taxable temporary differences associated with amortization of regulatory assets and liabilities being recovered from customers in rates, partially offset by higher earnings before income taxes.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the year ended December 31, 2025 as compared to December 31, 2024:

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**44**	For the year ended December 31, 2025, net earnings attributable to controlling interest were $329 million compared to $285 million for the same period in 2024. The increase was primarily due to the same reasons as identified in the quarter, partially offset by higher operating costs compared to the same period in 2024, which are retained by the utility.
Revenue	**208**	The increase was primarily due to: • an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior period, • an increase in revenue related to the amortization of prior year alternative revenue flow-through deferrals, and • a higher cost of natural gas recovered from customers, as approved by the BCUC, partially offset by • a decrease in revenue associated with regulatory deferrals. For the year ended December 31, 2025, gas sales volumes were lower compared to the same period in 2024 primarily due to lower consumption by transportation and residential customers, partially offset by higher consumption by LNG and industrial customers.
Cost of natural gas	**125**	The increase was primarily due to: • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior year, • an increase in total consumption by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity, and • a higher storage and transport cost, approved by the BCUC, of $1.260 per GJ for 2025, as compared to $1.102 per GJ for 2024.
Operation and maintenance	**29**	The increase was primarily due to inflationary increases, a higher service cost component of pension and OPEB expense, higher regulated operating costs and higher costs, the variances of which are retained by the utility.
Depreciation and amortization	**28**	The increase was primarily due to the same reasons as identified in the quarter.

Year		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Other income	**9**	Other income primarily consists of the equity component of AFUDC, interest income, and the non-service cost component of pension and other post-employment benefits, which is recognized as a credit to other income. The increase was primarily due to a higher equity component of AFUDC, partially offset by a decrease in the non-service cost component of pension and other post-employment benefits.
Income tax expense	**(8)**	The decrease was primarily due to higher deductible differences associated with property, plant and equipment, partially offset by higher earnings before income taxes, and higher taxable temporary differences associated with amortization of regulatory assets and liabilities being recovered from customers in rates.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2024 through December 31, 2025. 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, 2025	571	132
September 30, 2025	276	(1)
June 30, 2025	367	44
March 31, 2025	640	154
December 31, 2024	517	118
September 30, 2024	241	(6)
June 30, 2024	332	29
March 31, 2024	556	144

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

A summary of the past eight quarters reflects the seasonality associated with the Corporation's business. Due to the seasonal nature of natural gas consumption patterns based on weather and its impact on revenues, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters of the fiscal year and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. Certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year. As a result of the seasonality, interim net earnings are not indicative of net earnings on an annual basis. From time to time the Corporation has implemented tax loss utilization plans ("TLUP"), which would have an impact on earnings recognized during interim periods depending on the timing of implementing such structures.

December 2025/2024 – Net earnings were higher due to a higher investment in regulated assets, partially offset by lower favourable regulated variances, primarily attributable to operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2024.

September 2025/2024 – Net loss was lower due to a higher investment in regulated assets, higher favourable regulated variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2024, and lower operating costs, the variances of which are retained by the utility.

June 2025/2024 – Net earnings were higher due to a higher investment in regulated assets, and lower operating costs compared to the same period in 2024, the variances of which are retained by the utility.

March 2025/2024 – Net earnings were higher due to a higher investment in regulated assets, and higher favourable regulated variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2024, partially offset by higher operating costs, the variances of which are retained by the utility.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between December 31, 2025 and December 31, 2024:

Balance Sheet Account	**Increase (Decrease)** *($ millions)*	**Explanation**
Accounts receivable and other current assets	**(26)**	The decrease was primarily due to lower tariff-based trade receivables, primarily as a result of the elimination of carbon tax and lower volumes sold in the fourth quarter of 2025 as compared to the fourth quarter of 2024, partially offset by an increase in the delivery rate, as well as lower gas cost mitigation receivables.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Regulatory assets (current and long-term)	**303**	The increase was primarily due to: • an increase in regulated deferred income tax liabilities, the offset of which has been deferred as a regulatory asset, • an increase in DSM expenditures during the period, recognized as part of regulatory assets, • a $15 million increase in the regulatory asset recognized related to the revenue deficiency deferral as a result of the 2025 Annual Review Decision, • a $37 million increase in the meter costs recovery account related to the remaining net book value of meters removed from service as part of the AMI Project, • an increase in the RSAM regulatory asset due to variances in gas use for residential and commercial customers, and • an increase in the MCRA regulatory asset due to midstream costs incurred exceeding the costs recovered in customer rates and lower mitigation activities, partially offset by • a decrease in the RNG variance regulatory asset due to costs recovered in customer rates exceeding costs incurred to acquire RNG, and due to the transfer of the RNG mitigation revenue regulatory liability balance.
Property, plant and equipment, net	**380**	The increase was primarily due to capital expenditures of $1,232 million, $34 million in equity AFUDC, and changes in accrued capital expenditures of $13 million, less: • depreciation expense, excluding net salvage provision, of $205 million, • contributions in aid of construction ("CIAC"), inclusive of certain amounts provided for the EGP Project, of $630 million, • transferring $37 million in remaining net book value of meters removed from service, which have been recognized in the meter costs recovery deferral in regulatory assets, • disposal of assets of $6 million, the offset of which has been partially recognized in regulatory assets, • costs of removal of $17 million incurred, which are recognized against the net salvage provision in regulatory liabilities, and • changes in finance leases of $4 million.
Credit facilities	**(123)**	The decrease was primarily a result of repayments on credit facilities using proceeds from the receipt of cash deposits relating to construction costs to be incurred for the EGP Project, the issuance of $200 million of unsecured Medium Term Note ("MTN") Debentures in October 2025, and a $225 million equity issuance during the first quarter of 2025, partially offset by borrowings on credit facilities to fund the debt component of the Corporation's capital expenditure program during the period.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Accounts payable and other current liabilities	**99**	The increase was primarily due to: • an increase in cash deposits held relating to construction costs to be incurred for the EGP Project, • higher gas cost payables, due to a higher weighted average cost of gas purchased, and • higher accrued capital expenditures, partially offset by • a decrease in carbon tax payable of $68 million as a result of the provincial government of BC effectively repealing the consumer carbon tax by reducing the rate to zero on April 1, 2025, and • a change in the fair value of natural gas derivatives.
Long-term debt (current and long-term)	**200**	The increase was due to the issuance of $200 million of unsecured MTN Debentures in October 2025, the proceeds of which were used to repay borrowings on credit facilities in support of the debt component of the Corporation's capital expenditure program.
Regulatory liabilities (current and long-term)	**44**	The increase was primarily due to: • an increase in the net salvage provision, • an increase in the CCRA regulatory liability due to costs recovered in customer rates exceeding commodity costs incurred, partially offset by • a decrease in the MCRA regulatory liability due to midstream costs incurred exceeding the costs recovered in customer rates and lower mitigation activities, • a decrease in the RNG mitigation revenue regulatory liability, due to the transfer of the balance to the RNG variance regulatory asset, and • an increase in unrecognized actuarial gains in defined benefit pension and OPEB plans, the offset of which is deferred as a regulatory liability.
Deferred income tax	**122**	The increase was primarily due to higher deductible temporary differences associated with property, plant and equipment, lower taxable temporary differences associated with regulatory assets and liabilities, the utilization of carried-forward losses, partially offset by changes in other liabilities.
Other liabilities	**(21)**	The decrease was primarily due to a decrease in operating lease obligations, and due to a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**225**	The increase was due to a $225 million equity issuance during the first quarter of 2025, 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 dividend payments. Cash flow is also required to fund capital expenditure programs; pre-development capital costs; regulated deferral accounts, and those regulatory mechanisms that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation; and investments in DSM. Funding requirements are expected to be financed from a combination of cash flow from operations, borrowings under the credit facility, equity injections from FHI, and long-term debenture issuances in accordance with the deemed regulatory capital structure approved by the BCUC of 45 percent equity and 55 percent debt, and in certain circumstances, funding provided by CIAC for certain capital expenditures.

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

Year ended December 31	**2025**	2024	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**720**	735	(15)
Investing activities	**(815)**	(1,149)	334
Financing activities	**99**	426	(327)
Net change in cash	**4**	12	(8)

Operating Activities

Cash from operating activities was $15 million lower compared to the same period in 2024 primarily due to:

- changes in working capital, which was driven by changes in accounts payable that included a decrease in carbon tax payable during 2025 as a result of the provincial government of BC effectively repealing the consumer carbon tax by reducing the rate to zero on April 1, 2025, compared to an increase in carbon tax payable during 2024, as well as changes in tax receivable balances between years, partially offset by
- higher net earnings after non-cash adjustments.

Investing Activities

Cash used in investing activities was $334 million lower compared to the same period in 2024 primarily due to lower net capital expenditures, where construction costs on the EGP Project were funded through contributions received from Woodfibre LNG recognized as CIAC during 2025, whereas FEI funded approximately $400 million of capital expenditures on the EGP Project during 2024, as well as $5 million related to proceeds on disposal of assets, partially offset by higher DSM expenditures during 2025 compared to 2024.

Financing Activities

Cash from financing activities was $327 million lower compared to the same period in 2024. During 2025, net repayments on the credit facility and capital expenditures were funded, in part, by the issuance of $200 million of unsecured MTN Debentures in October 2025, and a $225 million issuance of common shares, whereas during 2024 net proceeds from the credit facility and from a $275 million issuance of common shares were used to fund a higher level of capital expenditures.

During 2025, FEI paid common share dividends of $200 million (2024 - $300 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, 2025	Total	Due within 1 Year	Due in Year 2	Due in Year 3	Due in Year 4	Due in Year 5	Due after 5 Years
($ millions)							
Gas purchase obligations (a)	**5,295**	697	515	432	358	313	2,980
Long-term debt [1]	**3,495**	150	-	-	150	200	2,995
Interest obligations on long-term debt	**2,226**	157	155	155	155	144	1,460
Other (b)	**45**	28	6	3	2	2	4
Total	**11,061**	1,032	676	590	665	659	7,439

[1] Excludes unamortized debt issuance costs.

(a) The Corporation enters into contracts to purchase natural gas, RNG, 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 RNG 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, 2025. The RNG supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

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

In January 2012, two unrelated parties collectively purchased a 15 percent 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 percent 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, 2025, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $39 million (December 31, 2024 - $39 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 45 percent equity and 55 percent debt, effective January 1, 2023 as a result of the GCOC Stage 1 Decision. This capital structure excludes the financing of goodwill and other non-regulated items that do not impact the deemed capital structure. As part of the last review performed and the resulting GCOC Stage 1 Decision, the BCUC determined that the common equity component of capital structure and ROE for FEI will remain in effect until otherwise determined by the Commission.

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

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

During 2025, Morningstar DBRS and Moody's issued updated credit rating reports confirming the Corporation's debenture ratings and outlook.

Credit Facilities and Debentures

Credit Facilities
In July 2025, the Corporation extended the maturity date of its $900 million syndicated operating credit facility to July 2030. The credit facility continues to incorporate a Sustainability Linked Loan component, with performance targets considering avoided emissions from renewable and low carbon gas and capital project opportunities with Indigenous participation. As at December 31, 2025, the Corporation also had a $55 million uncommitted letter of credit facility in place, which matures in March 2026.

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

($ millions)	**2025**	2024
Operating credit facility	**900**	900
Letter of credit facility	**55**	55
Draws on operating credit facility	**(395)**	(518)
Letters of credit outstanding	**(39)**	(39)
Credit facilities available	**521**	398

Debentures
On October 14, 2025, the Corporation entered into an agreement to issue $200 million of unsecured Medium Term Note ("MTN") Debentures. The MTN Debentures bear interest at a rate of 3.38 percent to be paid semi-annually and mature on October 16, 2030. The closing of the issuance occurred on October 16, 2025, with net proceeds being used to repay draws on the operating credit facility.

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.

PROJECTED CAPITAL EXPENDITURES

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenditures that will be incurred in the ongoing operation of its business.

The initial approval from the BCUC to proceed with capital projects can occur through a number of processes, including revenue requirement applications and Certificate of Public Convenience and Necessity ("CPCN") applications. Once the projects are approved, the regulatory process allows for capital project costs to be reviewed by the BCUC subsequent to the capital project being completed and in service to confirm that all costs are recoverable in customer rates.

The 2026 projected capital expenditures are approximately $1,151 million, inclusive of AFUDC and excluding customer CIAC that is inclusive of approximately $466 million in deposit funding to be applied from Woodfibre LNG related to the EGP project. The 2026 projected capital expenditures 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 2026 projected capital expenditures are dependent on timing of spending on multi-year capital projects, including the potential impact of new or revised tariffs, based in part on the timing of any remaining regulatory and permitting approvals required for certain projects. The 2025 capital expenditures were $1,261 million, inclusive of AFUDC and excluding CIAC.

Also included in these 2026 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 RNG 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.

Advanced Metering Infrastructure ("AMI") Project
In May 2021, FEI filed a CPCN application, in the amount of approximately $740 million, excluding AFUDC, to automate the meter reading process for FEI customers, providing better information access to customers as well as operational opportunities that support the safety, resiliency, and efficient operation of the gas distribution system. The CPCN application was approved by the BCUC in May 2023, and construction is expected to be substantially complete in 2028.

Transmission Integrity Management Capabilities ("TIMC") Project
The multi-year TIMC Project, which will be carried out in several phases, is focused on improving gas line safety and the integrity of the transmission system, including gas line modifications and looping. In May 2022, FEI's CPCN application for the Coastal Transmission System component of the TIMC Project, in the amount of

approximately $120 million, was approved by the BCUC, and construction is now substantially complete. In September 2022, FEI's CPCN application for the Interior Transmission System component of the TIMC Project, in the amount of approximately $75 million, was submitted to the BCUC. The CPCN application was approved by the BCUC in January 2024, and construction is expected to be substantially complete in 2026.

Tilbury LNG Storage Expansion ("TLSE") Project

In December 2020, FEI filed an initial CPCN application to replace the original Tilbury Base Plant. Supplemental evidence was provided in October 2024, and in October 2025, the CPCN application was approved by the BCUC in the amount of approximately $860 million, excluding AFUDC, with construction expected to begin as early as late 2026 depending on the progress and timing of various Environmental Assessment processes still requiring approval. Consistent with expansion options outlined in the CPCN, the approval will allow FEI to replace the original Tilbury Base Plant with a new, expanded LNG storage tank, as well as increased regasification capacity, to ensure FEI can continue to provide reliable and resilient energy services, including in the event of a disruption in the supply of natural gas to FEI's system.

Enterprise Resource Planning ("ERP") Modernization and Customer Information System ("CIS") Replacement Project

In November 2025, FEI and FBC filed a joint application with the BCUC for approval of capital expenditures related to a joint ERP Modernization Project and a CIS Replacement Project for FBC. The combined project will modernize FEI and FBC's core SAP enterprise applications and replace FBC's legacy CIS by upgrading to SAP's S/4HANA. The combined capital cost of the projects is approximately $145 million, to be allocated between FEI and FBC. A decision on the joint application is expected mid-2026.

Tilbury Phase 1B Expansion Project

This project consists of construction of additional liquefaction and dispensing facilities, including on-shore piping, in support of marine bunkering and optimizing the existing investment in the Tilbury Phase 1A Expansion Project, which was completed in 2018. As explained under "Directions to the BCUC", 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 2026, FEI will continue to evaluate the investment opportunity and proceed with necessary pre-Front-End Engineering Design ("FEED") and FEED studies.

Eagle Mountain Pipeline ("EGP") Project

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

As explained under "Directions to the BCUC" above, the BC Provincial government issued an OIC that grants FEI an exemption from the requirement to seek a CPCN approval from the BCUC for the EGP Project. In addition, FEI received approval from the BCUC, as directed by an OIC, in May 2023 for an amended rate schedule for Large Volume Industrial Transportation and two corresponding Transportation Agreements, which included a net investment by FEI of $750 million.

FEI and Woodfibre LNG had previously entered into a pre-execution work agreement, along with subsequent amendments and ancillary commercial agreements ("WFLNG Agreements"), that established the amount and timing of funding requirements to be provided by Woodfibre LNG to FEI for project feasibility and development costs prior to construction, and for capital expenditures during construction and into commissioning.

In August 2023, FEI either waived or satisfied remaining conditions under the WFLNG Agreements to move forward with initial construction activities, which started in September 2023. Capital expenditures incurred from September to December 2023 were funded through contributions received from Woodfibre LNG and recognized through CIAC as capital expenditures occur. As stipulated in the WFLNG Agreements, FEI's funding commencement date began January 1, 2024, which resulted in FEI incurring capital expenditures up to an amount of $400 million before contributions from Woodfibre LNG began again in September 2024, which are being recognized through CIAC as capital expenditures occur, with up to an additional $350 million of FEI investment upon project completion in 2027.

FEI's projected capital expenditures, net of AFUDC and forecasted contributions from Woodfibre LNG, will be $750 million by the time the project is complete in 2027.

Other Capital Projects
In addition to the above, beyond 2025 the Corporation continues to pursue additional LNG infrastructure investment opportunities in BC, including a further expansion of the Tilbury site as well as interconnection with a planned marine jetty.

In February 2020, in conjunction with FEI's parent company FHI, an initial project description for further expansion of the Tilbury site was filed with regulators to begin the federal impact assessment and provincial environmental assessment processes. This expansion incorporates an increase to storage capacity and strengthening of the resiliency of FEI's gas system, as included in the TLSE Project approved under a separate CPCN process, as well as enabling additional liquefaction capacity. The various Environmental Assessment processes related to FEI's further expansion of the Tilbury site, which include the TLSE Project, still require approval.

During 2024, separate Environmental Assessment certificates for the planned marine jetty were issued by the Province of BC and by the federal government to a partnership that includes FEI's parent, FHI, who is working towards building a marine jetty at the Tilbury site. If constructed, the marine jetty would rely on FEI's assets at the Tilbury site to service marine bunkering and potential export activities.

FEI's parent company FHI entered into an agreement with an Indigenous community in July 2022 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 the projected capital expenditures, FEI has a DSM Expenditures Plan which delivers a portfolio of energy efficiency and conservation measures and activities, which was accepted by the BCUC in February 2024. The DSM Expenditures Plan is expected to result in approximately $627 million of expenditures for the periods 2024 to 2027 as rate base additions.

BUSINESS RISK MANAGEMENT

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

Regulatory Approval and Rate Orders
The regulated operations of the Corporation are subject to the uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. The ability of the Corporation to recover the actual costs of providing services and to earn the approved rate of return is impacted by achieving the forecasts established in the rate-setting process. The cost for upgrading existing facilities and adding new facilities requires the approval of the BCUC for inclusion in the rate base, at times through a CPCN if certain criteria are met. There is no assurance that CPCNs or capital projects perceived

as required by the Corporation will be approved or that conditions to such approval will not be imposed. In addition, an inability to acquire any necessary regulatory approvals, especially those required for major projects needed to increase system capacity, could limit the Corporation's future growth opportunities.

Rate applications that 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 Framework for the Corporation for a term of 2025 through 2027. Rates during this term will be determined through a review process which will occur on an annual basis, however there can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the allowed rate of return.

Through the regulatory process, the BCUC approves the ROE that the Corporation is allowed to earn and the deemed capital structure. This regulatory process allows the Corporation a reasonable opportunity to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments, which is essential for on-going capital attraction and growth. However, there can be no assurance that the rate orders issued by the BCUC will permit the Corporation to recover all costs actually incurred and to earn the allowed rate of return. The BCUC periodically reviews the cost of capital for regulated utilities in BC, which could affect FEI's capital structure and allowed ROE. The last review concluded in 2023, and the timing of the next cost of capital review is not known. Any changes resulting from future cost of capital reviews could materially impact the Corporation's earnings.

A failure to obtain rates that recover the costs of providing service, or provide a reasonable opportunity to earn a fair return, may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed upgrades or expansion projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, have a material adverse effect on the Corporation's results of operations and financial position. Additionally, in 2024, the federal government enacted the GMTA, which imposes a 15 percent global minimum tax on profits for multinational enterprises with consolidated annual revenues exceeding a certain threshold. The immediate impact of the new rules may be mitigated by transitional safe harbours provided under the GMTA, however any future impact could impact tax expense for which the recovery through customer rates is not guaranteed.

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 would not be recoverable from customers.

Natural Gas Competitiveness

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

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

Government policy has also impacted the competitiveness of natural gas and the future use of natural gas in BC. Federally, the Canadian Net-Zero Emissions Accountability Act became law in June 2021 and establishes in legislation Canada's commitment to achieve net-zero emissions by 2050. Provincially, in October 2021, the

Government of BC released an update to its economic and climate action plan, the CleanBC Roadmap to 2030 (“CleanBC”). Originally introduced in 2018, CleanBC frames BC’s approach to reducing emissions and transitioning to a low-carbon economy. The update includes a series of actions designed to achieve the Government of BC’s legislated climate targets to reduce GHG emissions by 40 percent 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 phasing out of incentives for conventional gas-fired heating equipment, and a new high efficiency standard requiring space and water heating equipment to meet or exceed 100 percent efficiency after 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. Additional government policy may also be released in the future which could impact the competitiveness of natural gas in BC. For example, the Province completed an independent review of CleanBC in 2025, which remains under consideration and may give rise to further policy details, enabling regulation, and implementation plans.

In response to climate policy, FEI has increased the proportion of RNG into its gas supply portfolio through committed supply contracts and expects to continue to increase the proportion of RNG into its gas supply portfolio; however, these supply costs are significantly higher than the supply costs for conventional natural gas, which could impact cost competitiveness relative to electricity. An inability to flow through the full cost of gas supply could have a material adverse effect on the Corporation’s results of operations and financial position. Additionally, technology may not develop at a fast enough rate, or at a low enough cost, such that high efficiency gas appliances are able to meet efficiency requirements in the CleanBC or other government policy requirements, which may impact the demand for natural gas.

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

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

Commodity Price

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

Climate Change

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

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

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

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

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

Weather and Natural Disasters

The facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events, some of which could be caused by climate change. A major natural disaster, such as an earthquake, wildfire, flood, washout, landslide, avalanche or other similar natural event could severely damage the Corporation's natural gas transmission, distribution and storage systems and access to natural gas supply. Although the Corporation's facilities have been constructed, and are 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, or could be subject to liabilities associated with such events. 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 relating to the protection of the environment and other health and safety matters, 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 archaeological disturbances, 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, health 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

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

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

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

There can be no assurance that the current BCUC approved deferral mechanisms allowing for the flow through of natural gas supply costs will continue in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through the full cost of natural gas could have a material adverse effect on the Corporation's results of operations and financial position.

Permits

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

Indigenous Rights and Indigenous Engagement

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

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

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

Recent court decisions have created uncertainty in land tenure in British Columbia. As these matters are under appeal, their final outcome remains unknown. While the Corporation does not have material assets located on the lands that are at issue in the recent proceedings, some of the Corporation's facilities are situated on Indigenous and other lands pursuant to rights of way or other land tenure agreements or rights. Our inability to maintain such agreements or rights, including to maintain or renew such land rights or obtain replacement land rights, could have a material adverse effect on the Corporation's operations or overall financial position.

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 credit rating agencies, and general economic conditions. In the future, the ability to arrange sufficient financing could also be impacted by investment policies that limit financing of natural gas utilities and projects. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will be available on acceptable terms to fund capital expenditures and to repay existing debt.

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

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

Interest Costs

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

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, economic impacts of tariffs, trade relations, geopolitical events, inflation, and interest rates, energy prices, housing starts, and customer growth. New customer additions at the Corporation are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Corporation is also affected by changes in trends in housing starts from single family dwellings to multi-family dwellings, for which the proportion that use natural gas for space and hot water heating is lower. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Corporation's service territories. The level of these activities can influence energy demand which could have a material adverse effect on the Corporation.

Natural gas revenue variances from forecasts used 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 variances could have a material adverse effect on the Corporation's results of operations and financial position.

A severe and prolonged downturn in economic conditions could have a material adverse effect on the Corporation despite regulatory measures available for compensating for reduced demand or increased cost to customers, which could have a material adverse effect on the Corporation.

Counterparty Credit

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; however, the credit quality of counterparties can change rapidly. In the event of non-performance by counterparties, there could be a material adverse effect on the Corporation's results of operations and financial position.

Human Resources

The ability of the Corporation to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain skilled workforces. Competitive labour market conditions create challenges in attracting and retaining technical and professional staff. Like other utilities across Canada, the

Corporation is also faced with demographic challenges relating to such skilled workforces. The inability to attract, develop and retain skilled workforces could have a material adverse effect on the Corporation.

Labour Relations

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

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

Employee Future Benefits

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

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

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

Information Technology Infrastructure

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

Cybersecurity

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

Pandemics and Public Health Crises

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

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

Continued Reporting in Accordance with US GAAP

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

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

The Exposure Draft is currently being reviewed by the IASB against consultative feedback. The timing of publishing a final standard based on the IASB Exposure Draft is expected in the second half of 2026, with an expected effective date of January 1, 2029. The ultimate timing and impact of a requirement to adopt IFRS Accounting Standards for external reporting purposes is not yet known.

Legal, Administrative and Other Proceedings

Legal, administrative and other proceedings arise in the ordinary course of business and may include environmental, sustainability, or climate-related claims, employment-related claims, marketing and advertising related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, cost-recovery claims, competition-related proceedings, 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

Improvements to Income Tax Disclosures

ASU No. 2023-09, *Improvements to Income Tax Disclosures*, issued in December 2023, is effective for the Corporation January 1, 2025 on a prospective basis, with retrospective application permitted. Principally, it requires additional disclosure in annual financial statements of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. The updated disclosures required of ASU No. 2023-09 have been applied retrospectively and included in Note 20 and Note 21 to the Consolidated Financial Statements.

FEI considers the applicability and impact of all ASUs issued by FASB. During the year ended December 31, 2025, there were no other ASUs issued by FASB that have a material impact on the Corporation's Consolidated Financial Statements.

Future Accounting Pronouncements

The following updates have been issued by FASB, but have not yet been adopted by the Corporation. Any ASUs issued by FASB that are not included in the Corporation's Consolidated Financial Statements were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on the Corporation's Consolidated Financial Statements.

Disaggregation of Income Statement Expenses

ASU No. 2024-03, Disaggregation of Income Statement Expenses, issued in November 2024, is effective for the Corporation's December 31, 2027 annual financial statements, and for interim periods beginning in 2028 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires entities to disclose disaggregated information about five expense categories underlying its income statement line items. The Corporation is assessing the impact of adoption of this ASU on the disclosures to its Consolidated Financial Statements.

Targeted Improvements to the Accounting for Internal-Use Software

ASU No. 2025-06, Targeted Improvements to the Accounting for Internal-Use Software, issued in September 2025, is effective for the Corporation's December 31, 2028 annual financial statements, and may be adopted prospectively, retrospectively, or using a modified transition approach, with early adoption permitted. The ASU removes references to development stages and requires capitalization of software costs once funding is authorized and project completion is probable, including assessment of whether significant development uncertainty exists. The guidance also clarifies that all capitalized internal-use software costs must follow the disclosure requirements in ASC Topic 360, Property, Plant and Equipment. The Corporation is assessing the impact of adoption of this ASU on its consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

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

Regulation

Generally, the accounting policies used by the Corporation in its regulated operations are subject to examination and approval by the Corporation's regulatory authority, the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of 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, 2025, the Corporation recognized $2,023 million in current and long-term regulatory assets (December 31, 2024 - $1,720 million) and $461 million in current and long-term regulatory liabilities (December 31, 2024 - $417 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, 2025, the Corporation's property, plant and equipment and intangible assets were $7,405 million, or approximately 69 percent of total assets, compared to $7,013 million, or approximately 70 percent of total assets as at December 31, 2024. 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. 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 2025 or 2024.

As at December 31, 2025, goodwill totaled $913 million (December 31, 2024 - $913 million).

During 2025, 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 2025, was 6.38 percent, which is an increase from the 6.36 percent that was assumed in 2024. 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, 2025, and to determine the pension net benefit cost for 2026, is 5.00 percent. This is an increase from the 4.75 percent discount rate used to measure the projected benefit obligations as at December 31, 2024, and to determine the pension net benefit cost for 2025.

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 2026 related to its defined benefit pension plans, prior to regulatory adjustments, to be $7 million, unchanged from 2025.

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 2025 pension net benefit cost, and the related projected benefit obligations recognized in the Corporation's Consolidated Financial Statements:

Increase (Decrease) *($ millions)*	**Net Benefit Cost**	**Projected Benefit Obligation**
1% increase in the expected rate of return	**(9)**	**3**
1% decrease in the expected rate of return	**5**	**(53)**
1% increase in the discount rate	**(6)**	**(116)**
1% decrease in the discount rate	**12**	**148**

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, 2025, the Corporation had a pension projected benefit net liability of $23 million (December 31, 2024 - $32 million) and an OPEB projected benefit liability of $84 million (December 31, 2024 - $85 million). The increase in the projected pension benefit net liability during 2025 was primarily a result of the pension valuation updates for the Corporation's registered pension plans during the period. During 2025, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $13 million (2024 - $7 million).

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, 2025 the amount of accrued unbilled revenue recorded in accounts receivable was $164 million (December 31, 2024 - $144 million) on annual natural gas revenues of $1,766 million (December 31, 2024 - $1,538 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.

In 2024, the federal government enacted legislation with respect to EIFEL and the GMTA, both of which were applicable to the Corporation as of January 1, 2024. There was no material impact to the Corporation in the year as a result of the enacted legislation. The Corporation anticipates that any restricted interest and financing expenses that has been realized will be deductible in future taxation years.

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)	**2025**	2024
Assets		
Current	**-**	1
Long-term	**1**	1
Total assets	**1**	2
Liabilities		
Current	**(42)**	(74)
Long-term	**(17)**	(28)
Total liabilities	**(59)**	(102)
Total liabilities, net	**(58)**	(100)

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, 2025, 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)	**2025**	2024
Unrealized net loss recorded to current regulatory assets	**58**	100

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

Financial Instruments Not Measured At Fair Value
The following table includes the carrying value, excluding unamortized debt issuance costs, and estimated fair value of the Corporation's long-term debt as at December 31:

		2025		2024	
($ millions)	*Fair Value Hierarchy*	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,495**	**3,398**	3,295	3,252

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	**2025**	2024	2023
($ millions)			
Revenue	**1,854**	1,646	1,937
Net earnings attributable to controlling interest	**329**	285	337
Total assets	**10,757**	10,082	9,236
Long-term debt, excluding current portion	**3,324**	3,274	3,274
Dividends on common shares	**200**	300	240

2025/2024 – Revenue increased $208 million and net earnings increased $44 million over 2024. The increase in revenue was primarily due to an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior period, an increase in revenue related to the amortization of prior year alternative revenue flow-through deferrals, and a higher cost of gas recovered from customers, as approved by the BCUC, partially offset by an increase in revenue associated with regulatory deferrals. The increase in net earnings was primarily due to a higher investment in regulated assets, partially offset by lower favourable regulated variances, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2024.

The increase in total assets was mainly due to investment in DSM and the Corporation's capital expenditure program, as well as changes in rate stabilization accounts recognized in regulatory assets. Long-term debt increased due to the issuance of $200 million of unsecured MTN Debentures in October 2025, partially offset by the reclass of $150 million of unsecured MTN Debentures which mature in April 2026.

2024/2023 – Revenue decreased $291 million and net earnings decreased $52 million over 2023. The decrease in revenue was primarily due to an increase in the refund of the MCRA gas storage and transport cost regulatory liability, compared to the prior year, a lower cost of natural gas recovered from customers, as approved by the BCUC, and a decrease in revenue associated with regulatory deferrals, partially offset by an increase in delivery revenue approved for rate-setting purposes, resulting primarily from collecting in rates part of the 2024 impact of the GCOC Stage 1 Decision. The decrease in net earnings was primarily due to a $70 million lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2023, where no similar TLUP was implemented in 2024, and a decrease in gas mitigation incentive revenue, partially offset by a higher net investment in regulated assets, and lower operating 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 capital expenditures incurred on the EGP project as stipulated under the WFLNG Agreements, where FEI's funding commencement date began January 1, 2024, and which resulted in FEI incurring capital expenditures up to an amount of $400 million before contributions from Woodfibre LNG began again in September 2024, as well as an increase in regulatory assets. Long-term debt was consistent with 2023.

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 FAES. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries
The amounts charged to related parties for the years ended December 31 were as follows:

($ millions)	**2025**	2024
Operation and maintenance expense charged to FBC (a)	**13**	11
Operation and maintenance expense charged to FHI (b)	**2**	2
Operation and maintenance expense charged to FAES (c)	**1**	1
Total related party recoveries	**16**	14

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

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

(c) The Corporation charged FAES for management services and other labour.

Related Party Costs

The amounts charged by related parties for the years ended December 31 were as follows:

($ millions)	**2025**	2024
Operation and maintenance expense charged by FHI (a)	**15**	14
Operation and maintenance expense charged by FBC (b)	**9**	9
Total related party costs	**24**	23

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

(b) 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, and the amounts due to related parties, included in accounts payable and other current liabilities, were as follows as at December 31:

	2025		2024	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(1)**	-	(2)
FBC	**-**	**(1)**	1	-
Total (due to) due from related parties	**-**	**(2)**	1	(2)

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, was ratified in October 2024 and expires on June 30, 2028. The second collective agreement, representing customer service employees was ratified during June 2023 and expires on March 31, 2027.

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expired March 31, 2024. During October, a new collective agreement was ratified, which now expires on March 31, 2029. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

Carbon Tax Legislation

On April 1, 2025, the provincial government of BC effectively repealed the consumer carbon tax by reducing the rate to zero. As a result of these changes, FEI no longer collects carbon tax from customers. For FEI's customers, the change resulted in a reduction to their total utility bill. As a result of this change to the carbon tax legislated rate, the carbon tax payable included in accounts payable and other current liabilities in FEI's condensed consolidated financial statements as at December 31, 2025 was $nil (December 31, 2024 - $68 million).

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 418,568,459 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

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

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