ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2022

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting
Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AFRC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AFRC meets with management, internal auditors and Independent Registered Public Accounting Firm auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AFRC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and Independent Registered Public Accounting Firm auditors have unrestricted access to the AFRC.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2022, based on the framework established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2022.

PricewaterhouseCoopers LLP, an Independent Registered Public Accounting Firm appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company and its internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Gregory L. Ebel
Gregory L. Ebel
President and Chief Executive Officer

/s/ Vern D. Yu
Vern D. Yu
Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies

February 10, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2022 and 2021, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill Impairment Assessment

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,440 million at December 31, 2022. As disclosed by management, an annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. The quantitative goodwill impairment assessment involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Midstream (Gas Transmission) and Renewable Power Generation reporting units and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage (Gas Distribution) reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples. Management elected to perform a qualitative goodwill impairment assessment as of April 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission and Gas Distribution and did not identify impairment indicators. Due to changes in the macroeconomic environment that led to a rise in interest rates, management performed a quantitative assessment as of December 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission, Gas Distribution and Renewable Power Generation. A goodwill impairment of $2,465 million was recorded in relation to the Gas Transmission reporting unit. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution or Renewable Power Generation reporting units.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the significant judgments required by management when developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures, terminal value growth rates, projected regulatory rate base, rate base multiple and earnings multiples used to estimate the fair value of the reporting units, as applicable, as of December 1, 2022. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of management's significant assumptions used in the quantitative assessment. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's quantitative goodwill impairment assessment, including controls over the determination of the fair value estimates of the Company's reporting units. These procedures also included, among others, testing management's process for developing the fair value estimates of the Company's reporting units. Testing management's process for developing the fair value estimates included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness and accuracy of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in determining the fair value estimates including discount rates, projected operating income, expected future capital expenditures, projected regulatory rate base and rate base multiple, terminal value growth rates and earnings multiples. Assessing the reasonableness of projected operating income, expected future capital expenditures and the projected regulatory rate base involved evaluating whether these significant assumptions were reasonable considering the current and past performance of the Company's reporting units, external industry data and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management’s discounted cash flow and earnings multiples models and evaluating the reasonableness of significant assumptions used in the models, specifically discount rates, terminal value growth rates, rate base multiple and earnings multiples.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 10, 2023

We have served as the Company’s auditor since 1949.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**29,150**	26,873	19,259
Gas distribution sales	**5,653**	4,026	3,663
Transportation and other services	**18,506**	16,172	16,165
Total operating revenues *(Note 4)*	**53,309**	47,071	39,087
Operating expenses			
Commodity costs	**28,942**	26,608	18,890
Gas distribution costs	**3,647**	2,094	1,779
Operating and administrative	**8,219**	6,712	6,749
Depreciation and amortization	**4,317**	3,852	3,712
Impairment of long-lived assets	**541**	—	—
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Total operating expenses	**48,131**	39,266	31,130
Operating income	**5,178**	7,805	7,957
Income from equity investments *(Note 13)*	**2,056**	1,711	1,136
Impairment of equity investments *(Note 13)*	**—**	(111)	(2,351)
Gain on joint venture merger transaction *(Note 13)*	**1,076**	—	—
Other income/(expense) *(Note 28)*	**(589)**	979	238
Interest expense *(Note 18)*	**(3,179)**	(2,655)	(2,790)
Earnings before income taxes	**4,542**	7,729	4,190
Income tax expense *(Note 25)*	**(1,604)**	(1,415)	(774)
Earnings	**2,938**	6,314	3,416
(Earnings)/loss attributable to noncontrolling interests	**65**	(125)	(53)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings	**2,938**	6,314	3,416
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**847**	162	(457)
Change in unrealized gain/(loss) on net investment hedges	**(971)**	49	102
Other comprehensive loss from equity investees	**(6)**	(12)	(1)
Excluded components of fair value hedges	**(35)**	(5)	5
Reclassification to earnings of loss on cash flow hedges	**143**	235	198
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(10)**	21	13
Reclassification to earnings of (gain)/loss on equity investees	**16**	(62)	—
Actuarial gain/(loss) on pension and OPEB	**312**	394	(167)
Foreign currency translation adjustments	**4,406**	(507)	(853)
Other comprehensive income/(loss), net of tax	**4,702**	275	(1,160)
Comprehensive income	**7,640**	6,589	2,256
Comprehensive income attributable to noncontrolling interests	**(21)**	(95)	(22)
Comprehensive income attributable to controlling interests	**7,619**	6,494	2,234
Preference share dividends	**(414)**	(373)	(380)
Comprehensive income attributable to common shareholders	**7,205**	6,121	1,854

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning of year	**7,747**	7,747	7,747
Redemption of preference shares	**(929)**	—	—
Balance at end of year	**6,818**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,799**	64,768	64,746
Shares issued on exercise of stock options	**53**	31	22
Share purchases at stated value	**(88)**	—	—
Other	**(4)**	—	—
Balance at end of year	**64,760**	64,799	64,768
Additional paid-in capital			
Balance at beginning of year	**365**	277	187
Stock-based compensation	**36**	28	30
Purchase of noncontrolling interest	**(43)**	—	—
Options exercised	**(50)**	(23)	(21)
Change in reciprocal interest	**—**	98	76
Other	**(33)**	(15)	5
Balance at end of year	**275**	365	277
Deficit			
Balance at beginning of year	**(10,989)**	(9,995)	(6,314)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Common share dividends declared	**(7,023)**	(6,818)	(6,612)
Dividends paid to reciprocal shareholder	**—**	8	17
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	—	(66)
Share purchases in excess of stated value	**(63)**	—	—
Other	**—**	—	(3)
Balance at end of year	**(15,486)**	(10,989)	(9,995)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**(1,096)**	(1,401)	(272)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**4,616**	305	(1,129)
Balance at end of year	**3,520**	(1,096)	(1,401)
Reciprocal shareholding			
Balance at beginning of year	**—**	(29)	(51)
Change in reciprocal interest	**—**	29	22
Balance at end of year	**—**	—	(29)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826	61,367
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**2,542**	2,996	3,364
Earnings/(loss) attributable to noncontrolling interests	**(65)**	125	53
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(28)**	(15)	(6)
Foreign currency translation adjustments	**114**	(15)	(25)
	86	(30)	(31)
Comprehensive income attributable to noncontrolling interests	**21**	95	22
Distributions	**(259)**	(271)	(300)
Contributions	**1,105**	15	23
Redemption of noncontrolling interests	**—**	(293)	(112)
Purchase of noncontrolling interest	**55**	—	—
Other	**47**	—	(1)
Balance at end of year	**3,511**	2,542	2,996
Total equity	**63,398**	63,368	64,363
Dividends paid per common share	**3.44**	3.34	3.24

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities			
Earnings	**2,938**	6,314	3,416
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**4,317**	3,852	3,712
Deferred income tax expense *(Note 25)*	**957**	1,091	447
Unrealized derivative fair value (gain)/loss, net *(Note 24)*	**1,280**	(173)	(756)
Income from equity investments *(Note 13)*	**(2,056)**	(1,711)	(1,136)
Distributions from equity investments	**1,827**	1,630	1,392
Impairment of long-lived assets	**541**	—	—
Impairment of equity investments *(Note 13)*	**—**	111	2,351
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Gain on joint venture merger transaction *(Note 13)*	**(1,076)**	—	—
(Gain)/loss on dispositions	**12**	(319)	(6)
Other	**37**	(73)	268
Changes in operating assets and liabilities *(Note 29)*	**(12)**	(1,466)	93
Net cash provided by operating activities	**11,230**	9,256	9,781
Investing activities			
Capital expenditures	**(4,647)**	(7,818)	(5,405)
Long-term investments and restricted long-term investments	**(1,041)**	(640)	(487)
Distributions from equity investments in excess of cumulative earnings	**763**	533	705
Additions to intangible assets	**(174)**	(275)	(215)
Acquisitions	**(828)**	(3,785)	(24)
Proceeds from joint venture merger transaction *(Note 13)*	**522**	—	—
Proceeds from dispositions	**—**	1,263	265
Affiliate loans, net	**135**	65	(16)
Net cash used in investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities			
Net change in short-term borrowings	**481**	394	223
Net change in commercial paper and credit facility draws	**(1,333)**	2,960	1,542
Debenture and term note issues, net of issue costs	**7,547**	8,032	5,230
Debenture and term note repayments	**(4,198)**	(2,264)	(4,463)
Sale of noncontrolling interest in subsidiary *(Note 8)*	**1,092**	—	—
Contributions from noncontrolling interests	**13**	15	23
Distributions to noncontrolling interests	**(259)**	(271)	(300)
Common shares issued	**3**	5	5
Common shares repurchased	**(151)**	—	—
Preference share dividends	**(338)**	(367)	(380)
Common share dividends	**(6,968)**	(6,766)	(6,560)
Redemption of preference shares	**(1,003)**	—	—
Redemption of preferred shares held by subsidiary	**—**	(415)	—
Other	**(314)**	(87)	(90)
Net cash provided by/(used in) financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)
Cash and cash equivalents and restricted cash at beginning of year	**320**	490	676
Cash and cash equivalents and restricted cash at end of year	**907**	320	490
Supplementary cash flow information			
Cash paid for income taxes	**495**	489	524
Cash paid for interest, net of amount capitalized	**2,920**	2,427	2,538
Property, plant and equipment and intangible assets non-cash accruals	**937**	831	801

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2022**	2021
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**861**	286
Restricted cash	**46**	34
Accounts receivable and other *(Note 9)*	**8,871**	6,862
Accounts receivable from affiliates	**114**	107
Inventory *(Note 10)*	**2,255**	1,670
	12,147	8,959
Property, plant and equipment, net *(Note 11)*	**104,460**	100,067
Long-term investments *(Note 13)*	**15,936**	13,324
Restricted long-term investments *(Note 14)*	**593**	630
Deferred amounts and other assets	**9,542**	8,613
Intangible assets, net *(Note 15)*	**4,018**	4,008
Goodwill *(Note 16)*	**32,440**	32,775
Deferred income taxes *(Note 25)*	**472**	488
Total assets	**179,608**	168,864
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**1,996**	1,515
Accounts payable and other *(Note 17)*	**11,392**	9,767
Accounts payable to affiliates	**105**	90
Interest payable	**763**	693
Current portion of long-term debt *(Note 18)*	**6,045**	6,164
	20,301	18,229
Long-term debt *(Note 18)*	**72,939**	67,961
Other long-term liabilities	**9,189**	7,617
Deferred income taxes *(Note 25)*	**13,781**	11,689
	116,210	105,496
Commitments and contingencies *(Note 31)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**6,818**	7,747
Common shares *(2,025 and 2,026 outstanding at December 31, 2022 and 2021, respectively)*	**64,760**	64,799
Additional paid-in capital	**275**	365
Deficit	**(15,486)**	(10,989)
Accumulated other comprehensive income/(loss) *(Note 23)*	**3,520**	(1,096)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826
Noncontrolling interests *(Note 20)*	**3,511**	2,542
	63,398	63,368
Total liabilities and equity	**179,608**	168,864

Variable Interest Entities (VIEs) *(Note 12)*
The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

/s/ Pamela L. Carter	**/s/ Teresa S. Madden**
Pamela L. Carter Chair	Teresa S. Madden Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through five business segments: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, and Energy Services. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of pipelines and terminals in Canada and the United States (US) that transport and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, and Other. This segment also includes Moda Midstream Operating, LLC (Moda), which was acquired on October 12, 2021 *(Note 8)* and is a component of Gulf Coast and Mid-Continent.

GAS TRANSMISSION AND MIDSTREAM
Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream, and Other.

GAS DISTRIBUTION AND STORAGE
Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec. We sold our investment in Noverco Inc. (Noverco), previously reported in the Gas Distribution and Storage segment, to Trencap L.P. on December 30, 2021 *(Note 13)*.

RENEWABLE POWER GENERATION
Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario and Québec, and in the states of Colorado, Texas, Indiana and West Virginia. We also have offshore wind assets in operation and under development in the United Kingdom, Germany and France. This segment also includes Tri Global Energy, LLC (TGE) which was acquired on September 27, 2022 *(Note 8).*

ENERGY SERVICES
Our Energy Services businesses in Canada and the US undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems. Energy Services also provides energy marketing services to North American refiners, producers and other customers.

ELIMINATIONS AND OTHER
In addition to the segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (US GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission (SEC) registrant, we are permitted to use US GAAP for the purposes of meeting both our Canadian and US continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement benefits and OPEB *(Note 26)*; commitments and contingencies *(Note 31)*; and estimates of losses related to environmental remediation obligations *(Note 31)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and the accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity’s operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis if there are changes in the facts and circumstances related to a VIE. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

REGULATION

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the Ontario Energy Board (OEB) and la Régie de l'energie du Québec. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI). Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2022 is probable over the periods described in *Note 7 - Regulatory Matters*.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income/(expense) for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized. The equity component of AFUDC is included as a non-cash reconciling item to earnings within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

For certain regulated operations to which US GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with US GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with US GAAP and no regulatory asset is recorded.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer creditworthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from our liquids and natural gas pipeline businesses are recognized under the terms of committed delivery contracts, rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote. We also have long-term contracts where the revenue profile does not align with the cash receipt schedule, resulting in the recognition of deferred revenue.

Certain offshore pipeline transportation contracts require us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For the years ended December 31, 2022, 2021 and 2020, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $238 million, $127 million and $292 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utility revenues are recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded on a gross basis as the related contracts are not held for trading purposes and we are acting as the principal in the transactions.

No non-affiliated customer exceeded 10.0% of our third-party revenues for the year ended December 31, 2022. Our largest non-affiliated customer accounted for approximately 13.5% and 13.6% of our third-party revenues for the years ended December 31, 2021 and 2020, respectively.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenue, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships
We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges
We use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges
We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges
Gains and losses arising from the translation of our net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We currently have designated a portion of our US dollar-denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar-denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives, as well as the translation of US dollar-denominated debt, are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from the disposal of a foreign operation.

Classification of Derivatives
We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS
Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. These investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Our equity investments are increased for contributions made to, and decreased for distributions received from, the investee. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS
Long-term investments that are restricted as to withdrawal or usage for the purposes of the CER's LMCI are presented as Restricted long-term investments in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS
Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost less impairment, if any, and adjusted for the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified. Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

Gains and losses arising from the translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect as at the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage for the purposes of the CER's LMCI or in accordance with specific commercial arrangements are presented as Restricted cash in the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

Long-term notes receivable from affiliates are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY

Inventory is comprised of natural gas held in storage by Enbridge Gas, crude oil and natural gas held primarily by businesses in the Energy Services segment and materials and supplies. Natural gas held in storage by Enbridge Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the OEB. Other inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; actual cost of removal of previously retired or decommissioned plant assets; the difference between the actual cost and approved cost of natural gas reflected in rates; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components, and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill beginning in the third quarter of 2022.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples for reporting units.

The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that have led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss for Gas Transmission *(Note 16)*. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution and Storage or Renewable Power Generation reporting units. Also, we did not identify any indicators of goodwill impairment during the remainder of 2022.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt securities and equity investments, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs. We determine whether the decline below carrying value is other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities. If the decline is determined to be other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

PENSION AND OTHER POSTRETIREMENT BENEFITS
We sponsor defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI, for our non-utilities' defined benefit pension plans and all defined benefit OPEB plans; and
- as a component of Deferred amounts and other assets and/or Other long-term liabilities, for our utilities' defined benefit pension plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulators, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets, over the expected average remaining service life of the plans' active employee group.

Our utility operations also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, our contributions are expensed when the contribution occurs.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge’s common shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to performance targets set out under the plan. We also award share settled RSUs which vest at the completion of a three-year term. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES
We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2022.

ADOPTION OF NEW ACCOUNTING STANDARDS
Disclosures About Government Assistance
Effective January 1, 2022, we adopted Accounting Standards Update (ASU) 2021-10 on a prospective basis. The new standard was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with governments that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Certain Lessor Leases with Variable Lease Payments
Effective January 1, 2022, we adopted ASU 2021-05 on a prospective basis. The new standard was issued in July 2021 to amend lessor accounting for certain leases with variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a loss at lease commencement if classified as a sales-type or a direct financing lease. The ASU amends the classification requirements of such leases for lessors to result in an operating lease classification. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts
Effective January 1, 2022, we adopted ASU 2021-04 on a prospective basis. The new standard was issued in May 2021 to clarify issuer accounting for modifications or exchanges of freestanding equity-classified written call options that remain equity classified after modification or exchange. The ASU requires an issuer to determine the accounting for the modification or exchange based on the economic substance of the modification or exchange. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
Effective January 1, 2022, we adopted ASU 2020-06 on a modified retrospective basis. The new standard was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. The adoption of this ASU did not have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**11,283**	**5,012**	**782**	**—**	**—**	**—**	**17,077**
Storage and other revenue	**235**	**350**	**308**	**—**	**—**	**—**	**893**
Gas gathering and processing revenue	**—**	**22**	**—**	**—**	**—**	**—**	**22**
Gas distribution revenue	**—**	**—**	**5,643**	**—**	**—**	**—**	**5,643**
Electricity and transmission revenue	**—**	**—**	**—**	**281**	**—**	**—**	**281**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**—**	**—**	**23,916**
Commodity sales	**—**	**—**	**—**	**—**	**29,150**	**—**	**29,150**
Other revenue[1,2]	**(81)**	**39**	**(20)**	**305**	**—**	**—**	**243**
Intersegment revenue	**615**	**3**	**16**	**(4)**	**25**	**(655)**	**—**
Total revenue	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,492	4,364	676	—	—	—	14,532
Storage and other revenue	147	255	246	—	—	—	648
Gas gathering and processing revenue	—	49	—	—	—	—	49
Gas distribution revenue	—	—	4,026	—	—	—	4,026
Electricity and transmission revenue	—	—	—	177	—	—	177
Total revenue from contracts with customers	9,639	4,668	4,948	177	—	—	19,432
Commodity sales	—	—	—	—	26,873	—	26,873
Other revenue[1,2]	375	42	13	336	—	—	766
Intersegment revenue	567	1	19	(1)	44	(630)	—
Total revenue	10,581	4,711	4,980	512	26,917	(630)	47,071

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	9,161	4,523	674	—	—	—	14,358
Storage and other revenue	94	274	203	—	—	—	571
Gas gathering and processing revenue	—	27	—	—	—	—	27
Gas distribution revenue	—	—	3,663	—	—	—	3,663
Electricity and transmission revenue	—	—	—	198	—	—	198
Total revenue from contracts with customers	9,255	4,824	4,540	198	—	—	18,817
Commodity sales	—	—	—	—	19,259	—	19,259
Other revenue[1,2]	584	44	17	389	—	(23)	1,011
Intersegment revenue	584	2	12	—	24	(622)	—
Total revenue	10,423	4,870	4,569	587	19,283	(645)	39,087

1 *Includes mark-to-market losses from our hedging program for the year ended December 31, 2022 of $431 million (2021 - $59 million gain; 2020 - $265 million gain).*

2 *Includes revenues from lease contracts. Refer to* Note 27 - Leases*.*

We disaggregate revenue into categories which represent our principal performance obligations within each business segment. These revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2022	**3,183**	**230**	**2,241**
Balance as at December 31, 2021	2,369	213	1,898

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or have partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2022 included in contract liabilities at the beginning of the year is $166 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2022, were $453 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGL • Sale of crude oil, natural gas and NGL
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized during the year ended December 31, 2022 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution and Storage customers are received on a continuous basis based on established billing cycles.

Certain contracts in our US offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period that is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs are recorded as contract liabilities. The FMPs are not considered to be a financing arrangement as payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations
Total revenue from performance obligations expected to be fulfilled in future periods is $58.6 billion, of which $7.6 billion is expected to be recognized during the year ending December 31, 2023.

The revenues excluded from the amounts above based on optional exemptions available under Accounting Standards Codification (ASC) 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts of revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE
Long-Term Transportation Agreements
For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Variable Consideration
Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

During the year ended December 31, 2022, revenue for the Canadian Mainline has been recognized in accordance with the terms of the Competitive Toll Settlement (CTS), which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until a new commercial arrangement is implemented and are subject to finalization and adjustment applicable to the interim period, if any. Due to the uncertainty of adjustment to tolling pursuant to a CER decision and potential customer negotiations, interim toll revenue recognized during the year ended December 31, 2022 is considered variable consideration.

Recognition and Measurement of Revenue

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	**—**	**—**	**127**	**—**	**127**
Revenue from products and services transferred over time[1]	**11,518**	**5,384**	**6,606**	**281**	**23,789**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**23,916**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	70	—	70
Revenue from products and services transferred over time[1]	9,639	4,668	4,878	177	19,362
Total revenue from contracts with customers	9,639	4,668	4,948	177	19,432

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	60	—	60
Revenue from products and services transferred over time[1]	9,255	4,824	4,480	198	18,757
Total revenue from contracts with customers	9,255	4,824	4,540	198	18,817

1 *Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.*

Performance Obligations Satisfied Over Time

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices

Prices for transportation and gas processing services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services, plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices, plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2022, 2021 and 2020 is as follows:

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**
Commodity and gas distribution costs	**—**	**—**	**(3,693)**	**(16)**	**(29,525)**	**645**	**(32,589)**
Operating and administrative	**(4,287)**	**(2,254)**	**(1,289)**	**(255)**	**(49)**	**(85)**	**(8,219)**
Impairment of long-lived assets	**(245)**	**—**	**—**	**(235)**	**(13)**	**(48)**	**(541)**
Impairment of goodwill *(Note 16)*	**—**	**(2,465)**	**—**	**—**	**—**	**—**	**(2,465)**
Income/(loss) from equity investments *(Note 13)*	**785**	**1,133**	**1**	**141**	**—**	**(4)**	**2,056**
Gain on joint venture merger transaction *(Note 13)*	**—**	**1,076**	**—**	**—**	**—**	**—**	**1,076**
Other income/(expense) *(Note 28)*	**59**	**210**	**79**	**45**	**(5)**	**(977)**	**(589)**
Earnings/(loss) before interest, income taxes and depreciation and amortization	**8,364**	**3,126**	**1,827**	**262**	**(417)**	**(1,124)**	**12,038**
Depreciation and amortization							**(4,317)**
Interest expense *(Note 18)*							**(3,179)**
Income tax expense *(Note 25)*							**(1,604)**
Earnings							**2,938**
Capital expenditures[1]	**1,418**	**1,690**	**1,499**	**50**	**—**	**33**	**4,690**
Total property, plant and equipment, net *(Note 11)*	**53,567**	**29,666**	**17,857**	**3,082**	**6**	**282**	**104,460**

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	10,581	4,711	4,980	512	26,917	(630)	47,071
Commodity and gas distribution costs	(25)	—	(2,147)	—	(27,174)	644	(28,702)
Operating and administrative	(3,431)	(1,877)	(1,143)	(180)	(48)	(33)	(6,712)
Income/(loss) from equity investments *(Note 13)*	759	813	42	101	—	(4)	1,711
Impairment of equity investments *(Note 13)*	—	(111)	—	—	—	—	(111)
Other income/(expense) *(Note 28)*	13	135	385	75	(8)	379	979
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,897	3,671	2,117	508	(313)	356	14,236
Depreciation and amortization							(3,852)
Interest expense *(Note 18)*							(2,655)
Income tax expense *(Note 25)*							(1,415)
Earnings							6,314
Capital expenditures[1]	4,051	2,420	1,343	16	1	54	7,885
Total property, plant and equipment, net *(Note 11)*	52,530	27,028	16,904	3,315	23	267	100,067

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	10,423	4,870	4,569	587	19,283	(645)	39,087
Commodity and gas distribution costs	(20)	—	(1,810)	(2)	(19,450)	613	(20,669)
Operating and administrative	(3,331)	(1,859)	(1,091)	(191)	(67)	(210)	(6,749)
Income/(loss) from equity investments *(Note 13)*	558	479	9	94	(3)	(1)	1,136
Impairment of equity investments *(Note 13)*	—	(2,351)	—	—	—	—	(2,351)
Other income/(expense) *(Note 28)*	53	(52)	71	35	1	130	238
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,683	1,087	1,748	523	(236)	(113)	10,692
Depreciation and amortization							(3,712)
Interest expense *(Note 18)*							(2,790)
Income tax expense *(Note 25)*							(774)
Earnings							3,416
Capital expenditures[1]	2,033	2,130	1,134	81	2	90	5,470
Total property, plant and equipment, net	48,799	25,745	16,079	3,495	24	429	94,571

1 Includes allowance for equity funds used during construction.

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Canada	**27,498**	20,474	16,453
US	**25,811**	26,597	22,634
	53,309	47,071	39,087

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment[1]

December 31,	**2022**	2021
(millions of Canadian dollars)		
Canada	**47,602**	47,102
US	**56,858**	52,965
	104,460	100,067

1 Amounts are based on the location where the assets are held.

6. EARNINGS PER COMMON SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. On December 30, 2021, we closed the sale of our minority ownership in Noverco. The weighted average number of common shares outstanding was reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million and 5 million as at December 31, 2021 and 2020, respectively, resulting from our reciprocal investment in Noverco.

DILUTED

The treasury stock method is used to determine the dilutive impact of stock options and RSUs. This method assumes any proceeds from the exercise of stock options and vesting of RSUs would be used to purchase common shares at the average market price during the period.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

December 31,	**2022**	2021	2020
(number of shares in millions)			
Weighted average shares outstanding	**2,025**	2,023	2,020
Effect of dilutive options and RSUs	**4**	2	1
Diluted weighted average shares outstanding	**2,029**	2,025	2,021

For the years ended December 31, 2022, 2021 and 2020, 10.4 million, 18.6 million and 29.8 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $56.49, $52.89 and $51.42, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion. Our significant regulated businesses and the related accounting impacts are described below.

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory Deferred income taxes balance and the related earnings impact would not be recorded.

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our mainline system and is subject to regulation by the CER. Tolls, excluding Lines 8 and 9, are governed by the 10-year CTS which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until new tolls are finalized and approved by the CER *(Note 4).* The CTS established a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. Under the CTS, we have recognized a regulatory asset of $2.1 billion as at December 31, 2022 (2021 - $2.1 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The US and Canadian portions of the Southern Lights Pipeline are regulated by the FERC and CER, respectively. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax return on equity (ROE) of 10%.

GAS TRANSMISSION AND MIDSTREAM

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast (M&N) Canada are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems currently operate under the terms of their respective 2022-2026 and 2022-2023 settlement agreements, which stipulate an allowable ROE and the continuation and establishment of certain deferral and variance accounts.

US Gas Transmission

Most of our US gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. The FERC regulates natural gas transmission in US interstate commerce including the establishment of rates for services, while rates for intrastate commerce and/or gathering services are regulated by the state agencies. Cost-of-service is the basis for the calculation of regulated tariff rates, although the FERC also allows the use of negotiated and discounted rates within contracts with shippers that may result in a rate that is above or below the FERC-regulated recourse rate for that service.

GAS DISTRIBUTION AND STORAGE

Enbridge Gas

Enbridge Gas' distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved ROE.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position.

December 31,	**2022**	2021	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**190**	15	2023
Under-recovery of fuel costs	**109**	114	2023
Other current regulatory assets	**305**	130	2023
Total current regulatory assets[1] *(Note 9)*	**604**	259	
Long-term regulatory assets			
Deferred income taxes[2]	**4,473**	4,176	Various
Long-term debt[3]	**378**	398	2032-2046
Negative salvage[4]	**265**	243	Various
Purchase gas variance	**244**	215	2024
Accounting policy changes[5]	**219**	157	Various
Pension plan receivable[6]	**40**	78	Various
Other long-term regulatory assets	**244**	339	Various
Total long-term regulatory assets[1]	**5,863**	5,606	
Total regulatory assets	**6,467**	5,865	
Current regulatory liabilities			
Other current regulatory liabilities	**167**	106	2023
Total current regulatory liabilities[7]	**167**	106	
Long-term regulatory liabilities			
Future removal and site restoration reserves[8]	**1,615**	1,543	Various
Regulatory liability related to US income taxes[9]	**918**	895	2050-2072
Pipeline future abandonment costs *(Note 14)*	**610**	649	Various
Pension plan payable[6]	**231**	—	Various
Other long-term regulatory liabilities	**250**	234	Various
Total long-term regulatory liabilities[7]	**3,624**	3,321	
Total regulatory liabilities	**3,791**	3,427	

1 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

2 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.

3 Represents our regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (Spectra Energy). The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

4 The negative salvage balance represents the recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.

5 This deferral primarily consists of unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas Limited, relating to the period up to our merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income/(expense) and recovered in rates, as previously approved by the OEB.

6 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

7 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

8 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

9 The regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. These balances will be refunded to customers in accordance with the respective rate settlements approved by the FERC.

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Tri Global Energy, LLC

On September 27, 2022, through a wholly-owned US subsidiary, we acquired all of the outstanding common units in TGE for cash consideration of $295 million (US$215 million) plus potential contingent payments of up to $72 million (US$53 million) dependent on the achievement of performance milestones by TGE (the TGE Acquisition). The TGE Acquisition is subject to customary closing and working capital adjustments. TGE is an onshore renewable project developer in the US with a development portfolio of wind and solar projects. The TGE Acquisition enhances Enbridge's renewable power platform and accelerates our North American growth strategy.

We accounted for the TGE Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities are recorded at their estimated fair values as at the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of TGE:

	September 27, 2022
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**3**
Long-term investments	**8**
Intangible assets (a)	**117**
Long-term assets	**3**
Current liabilities	**61**
Long-term debt *(Note 18)*	**18**
Long-term liabilities (b)	**105**
Goodwill (c)	**392**
Purchase price:	
Cash	**295**
Contingent consideration (d)	**49**
	344

a) Intangible assets consist of compensation expected to be earned by TGE on existing development contracts once certain project development milestones are met. Fair value was determined using a discounted cash flow method which is an income-based approach to valuation that estimates the present value of future projected benefits from the contracts. The intangible assets will be amortized on a straight-line basis over an expected useful life of three and a half years.

b) Long-term liabilities consist primarily of obligations payable to third parties which are contingent on the timing of milestones being met for certain projects. Fair value represents the present value of the future cash flow payments at the date of the TGE Acquisition.

c) Goodwill is primarily attributable to expected future returns from new opportunities to develop wind and solar projects, as well as enhanced scale and operational diversity of our renewable projects portfolio. The goodwill balance recognized has been assigned to our Renewable Power Generation segment and is tax deductible over 15 years.

d) We agreed to pay additional contingent consideration of up to US$53 million to TGE's former common unit holders if performance milestones are met on certain projects. The US$36 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined using an income-based approach.

Upon completion of the TGE Acquisition, we began consolidating TGE. For the period beginning September 27, 2022 through to December 31, 2022, operating revenues and earnings attributable to common shareholders generated by TGE were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2022 and 2021, as if the TGE Acquisition had been completed on January 1, 2021, was also immaterial.

Moda Midstream Operating, LLC
On October 12, 2021, through a wholly-owned US subsidiary, we acquired all of the outstanding membership interests in Moda for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments of up to US$150 million dependent on performance of the assets (the Moda Acquisition). The Moda Acquisition was also subject to customary closing and working capital adjustments. Moda owns and operates a light crude export platform with very large crude carrier capability. The Moda Acquisition aligns with and advances our US Gulf Coast export strategy and enables connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

We accounted for the Moda Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities were recorded at their estimated fair values as at the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of Moda:

	October 12, 2021
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	62
Property, plant and equipment (a)	1,480
Long-term investments (b)	427
Intangible assets (c)	1,781
Current liabilities	59
Long-term liabilities	17
Goodwill (d)	268
Purchase price:	
Cash	3,755
Contingent consideration (e)	187
	3,942

a) Due to the specialized nature of Moda's property, plant and equipment, which includes groups of assets configured for use as storage facilities, pipelines and export terminals, the depreciated replacement cost approach was adopted as the primary valuation methodology. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence. The fair value of land was determined using a market approach, which is based on rents and offerings for comparable properties.

b) Long-term investments represent Moda's 20% equity interest in Cactus II Pipeline LLC (Cactus II). The fair value of Cactus II was determined using the discounted cash flow method. The discounted cash flow method is an income-based approach to valuation which estimates the present value of future projected benefits from the investment.

c) Intangible assets consist primarily of customer relationships associated with long-term take-or-pay contracts. Fair value was determined using an income-based approach by estimating the present value of the after-tax earnings attributable to the contracts, including earnings associated with expected renewal terms, and will be amortized on a straight-line basis over an expected useful life of 10 years.

d) Goodwill is primarily attributable to uncontracted future revenues, existing assembled assets that cannot be duplicated at the same cost by a new entrant, and enhanced scale and geographic diversity which provide greater optionality and platforms for future growth. The goodwill balance recognized has been assigned to our Liquids Pipelines segment and is tax deductible over 15 years.

e) We agreed to pay additional contingent consideration of up to US$150 million to Moda's former membership interest holders if Moda's monthly volumes of crude oil loaded onto a vessel equal or exceed specified throughput levels. These performance requirements terminate the earlier of December 31, 2023 or the date the final contingent payment is made. The US$150 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition and was fully settled as at December 31, 2022.

Acquisition-related expenses incurred were approximately $21 million for the year ended December 31, 2021 and are included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Moda Acquisition, we began consolidating Moda. For the period beginning October 12, 2021 through to December 31, 2021, Moda generated approximately $80 million in operating revenues and $9 million in earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2021 and 2020, including the results of operations for Moda as if the Moda Acquisition had been completed on January 1, 2020, are as follows:

Year ended December 31,	2021	2020
(unaudited; millions of Canadian dollars)		
Operating revenues	47,339	39,435
Earnings attributable to common shareholders[1,2]	5,771	2,938

1 Acquisition-related expenses of $21 million (after-tax $16 million) were excluded from earnings attributable to common shareholders for the year ended December 31, 2021 and deducted for the year ended December 31, 2020.

2 Includes the amortization of fair value adjustments recorded for acquired property, plant and equipment, long-term investments and intangible assets of $193 million and $207 million (after-tax of $145 million and $155 million) for the years ended December 31, 2021 and 2020, respectively.

DISPOSITIONS
Athabasca Regional Oil Sands System
On October 5, 2022, we closed the sale of an 11.6% non-operating interest in seven pipelines in the Athabasca region of northern Alberta from our Regional Oil Sands System to Athabasca Indigenous Investments Limited Partnership (Aii), an entity representing 23 First Nation and Métis communities, for total consideration of approximately $1.1 billion, less customary closing adjustments. No gain or loss was recognized on the sale and a noncontrolling interest was recorded in our Consolidated Statements of Financial Position as at December 31, 2022 to reflect the interest held by Aii *(Note 20)*.

Subsequent to the sale, we maintained an 88.4% controlling interest in these assets, which are a component of our Liquids Pipelines segment, and continue to manage, operate and provide administrative services to them.

Line 10 Crude Oil Pipeline
In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. owned the Canadian and US portions of Line 10, respectively, and the related assets were included in our Liquids Pipelines segment. The transaction closed on June 1, 2020. No gain or loss on disposition was recorded.

Montana-Alberta Tie Line
On May 1, 2020, we closed the sale of the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta, for cash proceeds of approximately $189 million. After closing adjustments, a gain on disposal of $4 million was included in Other income/(expense) in the Consolidated Statements of Earnings. MATL was included in our Renewable Power Generation segment.

Ozark Gas Transmission
On April 1, 2020, we closed the sale of our Ozark Gas Transmission and Ozark Gas Gathering assets (Ozark assets) for cash proceeds of approximately $63 million. After closing adjustments, a gain on disposal of $1 million was included in Other income/(expense) in the Consolidated Statements of Earnings. The Ozark assets are composed of a transmission system that extends from southeastern Oklahoma through Arkansas to southeastern Missouri, and a fee-based gathering system that accesses Fayetteville Shale and Arkoma production. These assets were included in our Gas Transmission and Midstream segment.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**5,616**	4,957
Short-term portion of derivative assets *(Note 24)*	**1,015**	529
Regulatory assets *(Note 7)*	**604**	259
Gas imbalance	**461**	276
Taxes receivable	**323**	407
Other	**852**	434
	8,871	6,862

1 Net of allowance for expected credit losses of $92 million and $87 million as at December 31, 2022 and 2021, respectively.

10. INVENTORY

December 31,	2022	2021
(millions of Canadian dollars)		
Natural gas	**1,491**	953
Crude oil	**652**	624
Other	**112**	93
	2,255	1,670

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2022	2021
(millions of Canadian dollars)			
Pipelines	2.9 %	**66,528**	62,997
Facilities and equipment	3.5 %	**37,028**	34,331
Land and right-of-way[1]	2.2 %	**3,637**	3,320
Gas mains, services and other	2.6 %	**14,491**	13,606
Storage	2.3 %	**3,477**	3,099
Wind turbines, solar panels and other	4.1 %	**4,912**	4,912
Other	8.5 %	**1,611**	1,507
Under construction	— %	**2,316**	2,268
Total property, plant and equipment		**134,000**	126,040
Total accumulated depreciation		**(29,540)**	(25,973)
Property, plant and equipment, net		**104,460**	100,067

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense for the years ended December 31, 2022, 2021 and 2020 was $3.8 billion, $3.5 billion and $3.4 billion, respectively.

IMPAIRMENT

Magic Valley Wind Farm

Magic Valley Wind Farm (Magic Valley) has commercial challenges caused by electricity transmission congestion and a negative price differential arising from higher transmission costs resulting in a lower electricity sale price. As a result, we have recognized an impairment loss of $227 million to our investment in Magic Valley, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Bakken Pipeline System

The Bakken Pipeline System currently has long-term take-or-pay contracts that are set to expire in 2023. In connection with the upcoming expiration of the contracts, we have recognized an impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Liquids Pipelines segment.

Impairment charges were based on the amount by which the carrying value of the assets exceeded fair value, determined using expected discounted future cash flows.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Our consolidated VIEs consist of legal entities where we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide us with (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

The following table includes assets to be used to settle liabilities of our consolidated VIEs. The creditors of the liabilities of our consolidated VIEs do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	**2022**[1]	2021
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**426**	247
Restricted cash	**12**	4
Accounts receivable and other	**199**	99
Accounts receivable from affiliates	**23**	—
Inventory	**12**	9
	672	359
Property, plant and equipment, net	**7,707**	3,052
Long-term investments	**14**	16
Restricted long-term investments	**98**	101
Deferred amounts and other assets	**158**	2
Intangible assets, net	**102**	108
	8,751	3,638
Liabilities		
Accounts payable and other	**251**	84
Accounts payable to affiliates	**21**	—
	272	84
Other long-term liabilities	**859**	182
Deferred income taxes	**5**	5
	1,136	271
	7,615	3,367

1 *Includes assets and liabilities of newly created Enbridge Athabasca Midstream Trunkline LP and Enbridge Athabasca Midstream Investor LP following the sale of a minority interest in certain Athabasca Regional Oil Sands System assets. Refer to* Note 8 - Acquisitions and Dispositions.

We do not have obligations to provide additional financial support to any of our consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We currently hold interests in several non-consolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact their economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive kick-out rights or participating rights. The power to direct the activities of a majority of these non-consolidated limited partnership VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE, and none of the partners may make significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2022 and 2021 are presented below:

December 31, 2022	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**91**	**117**
EIH S.á r.l.[2]	**37**	**637**
Rampion Offshore Wind Limited[3]	**413**	**468**
Vector Pipeline L.P.[4]	**195**	**325**
Woodfibre LNG Limited Partnership[5,6]	**635**	**2,476**
Other[7]	**245**	**443**
	1,616	**4,466**

December 31, 2021	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	113	195
EIH S.á r.l.[2]	38	664
Enbridge Renewable Infrastructure Investments S.á r.l.[8,9]	54	2,121
Rampion Offshore Wind Limited[3]	450	508
Vector Pipeline L.P.[4]	189	374
Other[7]	210	426
	1,054	4,288

1 *As at December 31, 2022 and 2021, the maximum exposure to loss includes a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.*
2 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the three French offshore wind projects for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $56 million and $73 million held by us as at December 31, 2022 and 2021, respectively.*
3 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE.*
4 *As at December 31, 2022 and 2021, the maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable for $25 million and $80 million held by us as at December 31, 2022 and 2021, respectively, and an outstanding credit facility for $105 million as at December 31, 2022 and 2021.*
5 *In November 2022, Enbridge acquired a 30% interest in Woodfibre LNG Limited Partnership (Woodfibre). Refer to* Note 13 - Long-Term Investments*. Woodfibre is a VIE due to its lack of sufficient equity at risk to finance its activities. Enbridge does not hold decision-making rights to direct Woodfibre's activities that most significantly impact its economic performance.*
6 *As at December 31, 2022, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE.*
7 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the projects for which we would be liable in the event of default by the VIE.*
8 *As at December 31, 2021, the maximum exposure to loss included our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $807 million held by us as at December 31, 2021.*
9 *Following a reconsideration event in connection with an additional equity injection to facilitate debt and equity rebalancing of Enbridge Renewable Infrastructure Investments S.á r.l. (ERII) in the third quarter of 2022, ERII's equity is now sufficient for it to finance its activities without additional subordinated financial support. Therefore, it is no longer considered to be a VIE.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2022 and 2021.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2022**	2021
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company LLC[1]	75.0%	**1,968**	1,752
DCP Midstream, LLC (Class B Units)[2]	90.0%	**1,394**	469
Seaway Crude Holdings LLC	50.0%	**2,744**	2,634
Illinois Extension Pipeline Company, L.L.C.[3]	65.0%	**622**	593
Cactus II Pipeline LLC[4]	30.0%	**658**	434
Other	30.0% - 43.8%	**76**	71
Gas Transmission and Midstream			
Alliance Pipeline[5]	50.0%	**430**	504
Aux Sable[6]	42.7% - 50.0%	**214**	238
DCP Midstream, LLC (Class A Units)[7]	23.4%	**317**	397
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,274**	1,180
Nexus Gas Transmission, LLC	50.0%	**1,813**	1,724
Sabal Trail Transmission, LLC	50.0%	**1,535**	1,464
Southeast Supply Header, LLC	50.0%	**86**	82
Steckman Ridge, LP	50.0%	**91**	88
Vector Pipeline[8]	60.0%	**195**	189
Woodfibre LNG Limited Partnership	30.0%	**635**	—
Offshore - various joint ventures	22.0% - 74.3%	**314**	309
Other	20.0% - 33.3%	**—**	14
Gas Distribution and Storage			
Other	47.6% - 50.0%	**20**	20
Renewable Power Generation			
EIH S.à.r.l.[9]	51.0%	**37**	38
Enbridge Renewable Infrastructure Investments S.à.r.l.	51.0%	**163**	54
Rampion Offshore Wind Limited	24.9%	**413**	450
NextBridge Infrastructure LP	25.0%	**241**	186
Other	15.8% - 50.0%	**107**	92
OTHER LONG-TERM INVESTMENTS			
Gas Transmission and Midstream			
Fairwood Peninsula Energy Corporation		**22**	20
Gas Distribution and Storage			
Oakville Enterprises Corporation[10]		**48**	—
Renewable Power Generation			
Emerging Technologies and Other		**31**	32
Eliminations and Other			
Other[11]		**488**	290
		15,936	13,324

1 *Owns a 49.0% interest in Bakken Pipeline Investments L.L.C. Bakken Pipeline Investments L.L.C. owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System by us.*

2 *We own 90.0% of the Class B units of DCP Midstream, LLC. These units track to a 65.0% ownership in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% effective interest in Gray Oak by us. In 2021, we owned a 35.0% interest in Gray Oak Holdings LLC, which owned a 65.0% interest in Gray Oak, resulting in a 22.8% effective interest in Gray Oak by us.*

3 *Owns the Southern Access Extension Project.*

4 *On October 12, 2021, we acquired an effective 20.0% interest in Cactus II through the acquisition of Moda. Refer to* Note 8 - Acquisitions and Dispositions *for further discussion. On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%.*

5 *Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.*

6 *Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products LP and Aux Sable Midstream LLC in the US.*

7 We own 23.4% of the Class A units of DCP Midstream, LLC. These units track to a 56.5% ownership in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP by us. In 2021, we owned an effective 28.3% interest in DCP.
8 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US.
9 On March 18, 2021, we sold 49.0% of EIH S.à.r.l., an entity that holds our 50.0% interest in Éolien Maritime France SAS (EMF), to the Canada Pension Plan Investment Board. This resulted in a 25.5% effective interest in EMF. Through our investment in EMF, we own equity interests in three French offshore wind projects, including effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
10 On August 2, 2022, we acquired a 10.0% interest in Oakville Enterprises Corporation.
11 Consists of investments in debt and equity securities held by our wholly-owned captive insurance subsidiaries. Refer to Note 24 - Risk Management and Financial Instruments.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2022, this basis difference was $3.4 billion (2021 - $2.5 billion), of which $1.5 billion (2021 - $730 million) was amortizable.

For the years ended December 31, 2022, 2021 and 2020, distributions received from equity investments were $2.6 billion, $2.2 billion and $2.1 billion, respectively.

Summarized combined financial information of our interest in unconsolidated equity investments (presented at 100%) is as follows:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating revenues	**27,043**	20,021	14,096
Operating expenses	**23,043**	16,706	12,411
Earnings	**4,334**	3,022	2,324
Earnings attributable to Enbridge	**2,056**	1,711	1,136

December 31,	**2022**	2021
(millions of Canadian dollars)		
Current assets	**4,196**	3,639
Non-current assets	**53,405**	44,863
Current liabilities	**4,843**	3,741
Non-current liabilities	**18,595**	16,979
Noncontrolling interests	**3,785**	3,786

DCP Midstream, LLC

On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream, LLC, holding both our and P66's indirect ownership interests in Gray Oak and DCP. Our ownership in DCP Midstream, LLC consists of Class A and Class B Interests which track to our investments in DCP, included in the Gas Transmission and Midstream segment, and Gray Oak, included in the Liquids Pipelines segment, respectively. Through our investment in DCP Midstream, LLC, we increased our effective economic interest in Gray Oak to 58.5% from 22.8% and reduced our effective economic interest in DCP to 13.2% from 28.3%. As a result of the transaction, Enbridge will assume operatorship of Gray Oak in the second quarter of 2023.

We determined the fair value of our decrease in economic interest in DCP based on the unadjusted quoted market price of DCP's publicly traded common units on the transaction closing date. The fair value of our increased economic interest in Gray Oak was determined using the fair value prescribed to the change in our economic interest in DCP. As a result of the merger transaction and the realignment of our economic interests in DCP and Gray Oak, we also received cash consideration of approximately $522 million (US$404 million) and recorded an accounting gain of $1.1 billion (US$832 million) to Gain on joint venture merger transaction in the Consolidated Statements of Earnings. Both DCP and Gray Oak continue to be accounted for as equity method investments.

Woodfibre LNG Limited Partnership
On November 29, 2022, Enbridge acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre. Woodfibre will operate a liquified natural gas export facility in BC being constructed by us and our partners.

Noverco Inc.
On June 7, 2021, IPL System Inc., a wholly-owned subsidiary of Enbridge, entered into a purchase and sale agreement to sell its 38.9% common share and preferred share interest in Noverco to Trencap L.P. On December 30, 2021, we closed the sale of Noverco for cash proceeds of $1.1 billion. After closing adjustments, a gain on disposal of $303 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2021. Noverco was previously included in our Gas Distribution and Storage segment.

IMPAIRMENT OF EQUITY INVESTMENTS
PennEast Pipeline Company, LLC
PennEast Pipeline Company, LLC (PennEast) is a joint venture formed to develop a natural gas transmission pipeline to serve local distribution companies and power generators in southeastern Pennsylvania and New Jersey, is owned 20.0% by Enbridge, and is recorded as an equity method investment. In the third quarter of 2021, PennEast determined further development of the project was no longer viable and development of the project was ceased. As a result, we recorded an other-than-temporary impairment loss of $111 million on our investment for the year ended December 31, 2021 based on the estimated fair value of our share of the net assets. The carrying value of this investment as at December 31, 2022 and 2021 was nil and $12 million, respectively.

Steckman Ridge, LP
Steckman Ridge, LP (Steckman Ridge) is engaged in the storage of natural gas, is owned 50.0% by Enbridge, and is recorded as an equity method investment. During the year ended December 31, 2020, Steckman Ridge’s forecasted performance was adjusted for the expectation that future available capacity will be re-contracted at lower than expected rates. As a result, we recorded an other-than-temporary impairment loss of $221 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $91 million and $88 million, respectively.

Southeast Supply Header, L.L.C.
Southeast Supply Header, L.L.C. (SESH) provides natural gas transmission services from east Texas and northern Louisiana to the southeast markets of the Gulf Coast, is owned 50.0% by Enbridge, and is recorded as an equity method investment. The forecasted performance of SESH was revised during the year ended December 31, 2020 to reflect downward revisions to future negotiated rates as well as higher than expected available capacity levels, caused primarily by a significant contract expiry. As a result, we recorded an other-than-temporary impairment loss of $394 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $86 million and $82 million, respectively.

DCP Midstream, LLC
DCP Midstream, LLC, an entity of which we had a 50.0% ownership interest in prior to the joint venture merger transaction with P66, holds an equity interest in DCP. A decline in the market price of DCP's publicly traded units during the first quarter of 2020 resulted in an other-than-temporary impairment loss on our investment in DCP Midstream, LLC of $1.7 billion for the year ended December 31, 2020. In addition, we incurred losses of $324 million through our equity earnings pick up in relation to asset and goodwill impairment losses recorded by DCP. The carrying value of our investment in DCP Midstream, LLC (Class A Units) as at December 31, 2022 and 2021 was $317 million and $397 million, respectively.

Our investments in PennEast, Steckman, SESH and DCP Midstream, LLC (Class A Units) form part of our Gas Transmission and Midstream segment. The impairment losses were recorded within Impairment of equity investments in the Consolidated Statements of Earnings.

14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues in the Consolidated Statements of Earnings and Restricted long-term investments in the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense in the Consolidated Statements of Earnings and Other long-term liabilities in the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the US and Canada.

As at December 31, 2022 and 2021, we had restricted long-term investments held in trust and classified as available-for-sale of $593 million and $630 million, respectively.

We had Restricted long-term investments held in trust totaling $236 million and $217 million as at December 31, 2022 and 2021, respectively, which are classified as Level 1 in the fair value hierarchy. We also had Restricted long-term investments held in trust totaling $357 million (cost basis - $437 million) and $413 million (cost basis - $383 million) as at December 31, 2022 and 2021, respectively, which are classified as Level 2 in the fair value hierarchy. There were unrealized holding losses of $122 million and $8 million on our Restricted long-term investments for the years ended December 31, 2022 and 2021, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $610 million and $649 million as at December 31, 2022 and 2021, respectively *(Note 7)*.

15. INTANGIBLE ASSETS

December 31, 2022	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.9%	**2,019**	**(1,042)**	**977**
Power purchase agreements	4.2%	**64**	**(23)**	**41**
Project agreement[1]	4.0%	**163**	**(36)**	**127**
Customer relationships	8.6%	**2,701**	**(459)**	**2,242**
Other intangible assets	5.9%	**621**	**(148)**	**473**
Under development	—%	**158**	**—**	**158**
		5,726	**(1,708)**	**4,018**

December 31, 2021	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.0%	2,067	(1,148)	919
Power purchase agreements	4.5%	63	(21)	42
Project agreement[1]	4.0%	152	(27)	125
Customer relationships	8.5%	2,532	(215)	2,317
Other intangible assets	3.9%	475	(116)	359
Under development	—%	246	—	246
		5,535	(1,527)	4,008

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.

For the years ended December 31, 2022, 2021 and 2020, our amortization expense related to intangible assets totaled $483 million, $348 million and $294 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2023 to 2027 is $498 million.

16. GOODWILL

	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2021	7,828	19,480	5,378	—	2	32,688
Foreign exchange and other	(55)	(145)	—	—	—	(200)
Acquisition[3]	268	—	19	—	—	287
Balance at December 31, 2021[1,2]	8,041	19,335	5,397	—	2	32,775
Impairment	**—**	**(2,465)**	**—**	**—**	**—**	**(2,465)**
Foreign exchange and other	**506**	**1,236**	**—**	**(4)**	**—**	**1,738**
Acquisition[4]	**—**	**—**	**—**	**392**	**—**	**392**
Balance at December 31, 2022[1,2]	**8,547**	**18,106**	**5,397**	**388**	**2**	**32,440**

1 Gross goodwill as at December 31, 2022 and 2021 was $36.5 billion and $34.4 billion, respectively.
2 Accumulated impairment as at December 31, 2022 and 2021 was $4.1 billion and $1.6 billion, respectively.
3 In 2021 we recorded $268 million of goodwill related to the acquisition of Moda. Refer to Note 8 - Acquisitions and Dispositions.
4 In 2022, we recorded $392 million of goodwill related to the acquisition of TGE. Refer to Note 8 - Acquisitions and Dispositions.

IMPAIRMENT
Gas Transmission
During the year ended December 31, 2022, we recorded goodwill impairment of $2.5 billion related to our Gas Transmission reporting unit. The fair value of the reporting unit, determined using a combination of discounted cash flow and earnings multiples techniques, was impacted by a rise in cost of capital and lower projected long term growth rates for our existing assets.

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**5,235**	4,470
Dividends payable	**1,825**	1,773
Current deferred credits	**1,056**	853
Construction payables and contractor holdbacks	**937**	844
Current derivative liabilities *(Note 24)*	**898**	717
Taxes payable	**683**	478
Other	**758**	632
	11,392	9,767

18. DEBT

December 31,	Weighted Average Interest Rate[9]	Maturity	**2022**	2021
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	3.5%	2023 - 2051	**12,060**	10,992
Medium-term notes	3.8%	2023 - 2064	**8,223**	8,123
Sustainability-linked bonds	2.0%	2032 - 2033	**3,355**	2,363
Fixed-to-fixed subordinated term notes[1]	4.1%	2080 - 2083	**3,596**	1,263
Fixed-to-floating rate subordinated term notes[2]	5.9%	2077 - 2078	**6,736**	6,442
Floating rate notes[3]		2023 - 2024	**1,491**	1,579
Commercial paper and credit facility draws	4.8%	2023 - 2027	**7,984**	7,837
Other[4]			**15**	5
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.5%	2024 - 2027	**4,199**	4,845
Other[4]			**7**	7
Enbridge Energy Partners, L.P.				
Senior notes	6.5%	2025 - 2045	**3,320**	3,095
Enbridge Gas Inc.				
Medium-term notes	4.1%	2023 - 2052	**9,535**	9,010
Debentures	9.1%	2024 - 2025	**210**	210
Commercial paper and credit facility draws	4.5%	2024	**2,000**	1,515
Other[4]			**1**	—
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0%	2040	**921**	949
Enbridge Pipelines Inc.				
Medium-term notes[5]	4.2%	2023 - 2051	**5,425**	5,575
Debentures	8.2%	2024	**200**	200
Commercial paper and credit facility draws	4.6%	2024	**312**	667
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	**222**	240
Spectra Energy Capital, LLC				
Senior notes	7.0%	2032 - 2038	**234**	218
Algonquin Gas Transmission, LLC				
Senior notes	3.3%	2024 - 2029	**1,152**	1,074
East Tennessee Natural Gas, LLC				
Senior notes	3.1%	2024	**258**	240
Texas Eastern Transmission, LP				
Senior notes	3.3%	2028 - 2048	**3,455**	3,095
Spectra Energy Partners, LP				
Senior notes	4.3%	2024 - 2045	**4,336**	4,042
Tri Global Energy, LLC				
Senior notes	12.7%	2024	**18**	—
Westcoast Energy Inc.				
Medium-term notes	4.9%	2024 - 2041	**1,225**	1,475
Debentures	8.1%	2025 - 2026	**275**	275
Fair value adjustment			**608**	667
Other[6]			**(393)**	(363)
Total debt[7]			**80,980**	75,640
Current maturities			**(6,045)**	(6,164)
Short-term borrowings[8]			**(1,996)**	(1,515)
Long-term debt			**72,939**	67,961

1 *For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*

2 *For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate or the London Interbank Offered Rate (LIBOR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*

3 *The notes carry an interest rate equal to Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points and SOFR plus a margin of 63 basis points.*

4 *Primarily finance lease obligations.*

5 *Included in medium-term notes is $100 million with a maturity date of 2112.*

6 *Primarily unamortized discounts, premiums and debt issuance costs.*

7 *2022 - $38 billion and US$31 billion; 2021 - $36 billion and US$31 billion. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.*

8 *Weighted average interest rates on outstanding commercial paper were 4.5% as at December 31, 2022 (2021 - 0.5%).*

9 *Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2022.*

As at December 31, 2022, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2022, we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2023 to 2027.

As at December 31, 2022 and 2021, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $10.5 billion and $11.3 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2022, we completed the following long-term debt issuances totaling US$3.2 billion and $3.4 billion:

Company	Issue Date			Principal Amount
(millions of Canadian dollars unless otherwise stated)				
Enbridge Inc.				
	January 2022	5.00%	fixed-to-fixed subordinated notes due January 2082[1]	$750
	February 2022	Floating rate senior notes due February 2024[2]		US$600
	February 2022	2.15%	senior notes due February 2024	US$400
	February 2022	2.50%	senior notes due February 2025	US$500
	September 2022	7.38%	fixed-to-fixed subordinated notes due January 2083[3]	US$500
	September 2022	7.63%	fixed-to-fixed subordinated notes due January 2083[4]	US$600
	November 2022	5.70%	medium-term notes due November 2027	$600
	November 2022	6.10%	sustainability-linked medium-term notes due November 2032[5]	$900
	November 2022	6.51%	medium-term notes due November 2052	$500
Enbridge Gas Inc.				
	August 2022	4.15%	medium-term notes due August 2032	$325
	August 2022	4.55%	medium-term notes due August 2052	$325
Texas Eastern Transmission LP				
	December 2022	6.20%	senior notes due December 2032	US$600

1 *For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 3.54%. Subsequent to year 10, every five years, the Five-Year Government of Canada bond yield is reset. At year 30, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 4.29%.*

2 *Notes carry an interest rate set to equal the SOFR plus a margin of 63 basis points.*

3 *For the initial five years, the notes carry a fixed interest rate. At year five, the interest rate will be set to equal to the Five-Year US Treasury rate plus a margin of 3.71%. At year 10, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 3.96%. Subsequent to year 10, every five years, the Five-Year US Treasury rate is reset. At year 25, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.71%.*

4 *For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.42%. Subsequent to year 10, every five years, the Five-Year US Treasury rate will be reset. At year 30, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 5.17%.*

5 *The sustainability-linked medium-term notes are subject to a sustainability performance target of 35% reduction in emissions intensity at an observation date of December 31, 2030. If the target is not met, on November 9, 2031, the interest rate will be set to equal 6.10% plus a margin of 70 basis points.*

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2022, we completed the following long-term debt repayments totaling $1.5 billion and US$2.0 billion, respectively:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2022	Floating rate notes[1]		US$750
	February 2022	4.85%	medium-term notes	$200
	July 2022	2.90%	senior notes	US$700
	December 2022	3.19%	medium-term notes	$350
	December 2022	3.19%	medium-term notes	$450
Enbridge Gas Inc.				
	April 2022	4.85%	medium-term notes	$125
Enbridge Pipelines (Southern Lights) L.L.C.				
	June and December 2022	3.98%	senior notes	US$72
Enbridge Pipelines Inc.				
	November 2022	2.93%	medium-term notes	$150
Enbridge Southern Lights LP				
	June and December 2022	4.01%	senior notes	$18
Texas Eastern Transmission, LP				
	October 2022	2.80%	senior notes	US$500
Westcoast Energy Inc.				
	December 2022	3.12%	medium-term notes	$250

1 Notes carried an interest rate set to equal the Three-Month LIBOR plus a margin of 50 basis points.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2022, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Debentures and term notes	**2,910**	2,806	2,873
Commercial paper and credit facility draws	**388**	114	163
Amortization of fair value adjustment	**(45)**	(50)	(54)
Capitalized interest	**(74)**	(215)	(192)
	3,179	2,655	2,790

19. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets and obligations related to right-of way agreements and contractual leases for land use.

The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% to 9.0%).

A reconciliation of movements in our ARO liabilities is as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Obligations at beginning of year	**502**	496
Liabilities incurred	**30**	—
Liabilities settled	**(126)**	(67)
Change in estimate and other	**51**	70
Foreign currency translation adjustment	**24**	(3)
Accretion expense	**7**	6
Obligations at end of year	**488**	502
Presented as follows:		
Accounts payable and other	**83**	160
Other long-term liabilities	**405**	342
	488	502

20. NONCONTROLLING INTERESTS

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Algonquin Gas Transmission, LLC	**400**	377
Enbridge Athabasca Midstream Investor Limited Partnership[1]	**1,106**	—
Maritimes & Northeast Pipeline, L.L.C.	**582**	546
Renewable energy assets	**1,302**	1,503
Westcoast Energy Inc.[2]	**117**	116
Other	**4**	—
	3,511	2,542

1 *On October 5, 2022, we closed the sale of an 11.6% non-operating interest in certain assets from our Regional Oil Sands System to Aii. Refer to* Note 8 - Acquisitions and Dispositions.

2 *During 2021, Westcoast Energy Inc. redeemed all of its remaining Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares.*

21. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2022		2021		2020	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,026**	**64,799**	2,026	64,768	2,025	64,746
Shares issued on exercise of stock options	**2**	**53**	—	31	1	22
Share purchases at stated value[1]	**(3)**	**(88)**	—	—	—	—
Other	**—**	**(4)**	—	—	—	—
Balance at end of year	**2,025**	**64,760**	2,026	64,799	2,026	64,768

1 *Reflects the repurchase and cancellation of common shares under our normal course issuer bid.*

PREFERENCE SHARES

December 31,	**2022** Number of Shares	**2022** Amount	2021 Number of Shares	2021 Amount	2020 Number of Shares	2020 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	18	457	18	457
Preference Shares, Series C[1]	**—**	**—**	2	43	2	43
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J[2]	**—**	**—**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**24**	**600**	24	600	24	600
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 17[3]	**—**	**—**	30	750	30	750
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(135)**		(155)		(155)
Balance at end of year		**6,818**		7,747		7,747

1 On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.
2 On June 1, 2022, we redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J.
3 On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20%	$1.30052	$25	June 1, 2027	Series C
Preference Shares, Series D	4.46%	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69%	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38%	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series L[6]	5.86%	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	5.09%	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38%	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07%	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95%	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74%	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38%	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45%	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10%	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94%	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04%	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98%	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 19	4.90%	$1.22500	$25	March 1, 2023	Series 20

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.*

2 *Preference Shares, Series A may be redeemed any time at our option. For all other series of preference shares, we may at our option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.*

4 *With the exception of Preference Shares, Series A, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in year) x Three-Month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.*

6 *The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.*

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of our shareholders in connection with any takeover offer. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

22. STOCK OPTION AND STOCK UNIT PLANS

We maintain three long-term incentive compensation plans: the ISO Plan, the PSU Plan and the RSU Plan. Total stock-based compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 was $260 million, $157 million and $145 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

Certain key employees are granted ISOs to purchase common shares at the grant date market price. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2022	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**34,017**	**49.28**		
Options granted	**3,430**	**49.58**		
Options exercised[1]	**(8,684)**	**44.55**		
Options cancelled or expired	**(1,139)**	**51.32**		
Options outstanding at end of year	**27,624**	**48.46**	**5.7**	**133**
Options vested at end of year[2]	**17,631**	**49.20**	**4.4**	**84**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $66 million, $24 million and $13 million, respectively, and cash received on exercise was $3 million, $2 million and $4 million, respectively.

2 The total fair value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $21 million, $25 million and $30 million, respectively.

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2022**	2021	2020
Fair value per option *(Canadian dollars)*[1]	**5.07**	4.10	4.01
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**21.9%**	25.5%	18.3%
Expected dividend yield[4]	**6.5%**	7.6%	5.9%
Risk-free interest rate[5]	**1.8%**	0.7%	1.3%

1 Options granted to US employees are based on the New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the US and the Canadian options. The fair values per option for the years ended December 31, 2022, 2021 and 2020 were $4.78, $3.91 and $3.75, respectively, for Canadian employees and US$4.62, US$3.65 and US$3.62, respectively, for US employees.

2 The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian bond yields and the US Treasury bond yields.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for ISOs was $15 million, $16 million and $24 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $12 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of 2.0 if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, infrequent or other non-operating factors, relative to targets established at the time of grant. To calculate the 2022 expense, a multiplier of 1.25 was used for 2022 PSU grants, 1.25 for 2021 PSU grants and 2.00 for the 2020 PSU grants.

December 31, 2022	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,429**		
Units granted	**1,467**		
Units cancelled	**(131)**		
Units matured[1]	**(1,700)**		
Dividend reinvestment	**184**		
Units outstanding at end of year	**3,249**	**1.1**	**261**

1 The total amount paid during the years ended December 31, 2022, 2021 and 2020 for PSUs was $90 million, $70 million and $14 million, respectively.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for PSUs was $169 million, $56 million and $76 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested PSUs was $72 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Under RSU awards, cash awards are paid to certain of our employees vesting in equal installments on each of the first, second and third anniversaries of the grant date. Share-settled awards are given to certain senior management employees following a three year maturity period. RSU holders receive shares or cash equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2022	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**2,705**		
Units granted	**1,400**		
Units cancelled	**(134)**		
Units matured[1]	**(602)**		
Dividend reinvestment	**196**		
Units outstanding at end of year	**3,565**	**1.0**	**185**

1 The total amount paid during the years ended December 31, 2022, 2021 and 2020 for RSUs was $32 million, $72 million and $27 million, respectively.

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for RSUs was $76 million, $85 million and $44 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested RSUs was $35 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

23. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2022, 2021 and 2020 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2022	**(897)**	**—**	**(166)**	**56**	**(5)**	**(84)**	**(1,096)**
Other comprehensive income/(loss) retained in AOCI	**1,125**	**(35)**	**(971)**	**4,292**	**(6)**	**411**	**4,816**
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	**186**	**—**	**—**	**—**	**—**	**—**	**186**
Foreign exchange contracts[2]	**(4)**	**—**	**—**	**—**	**—**	**—**	**(4)**
Other contracts[3]	**4**	**—**	**—**	**—**	**—**	**—**	**4**
Amortization of pension and OPEB actuarial gain[4]	**—**	**—**	**—**	**—**	**—**	**(14)**	**(14)**
Other	**—**	**—**	**—**	**—**	**16**	**—**	**16**
	1,311	**(35)**	**(971)**	**4,292**	**10**	**397**	**5,004**
Tax impact							
Income tax on amounts retained in AOCI	**(250)**	**—**	**—**	**—**	**—**	**(99)**	**(349)**
Income tax on amounts reclassified to earnings	**(43)**	**—**	**—**	**—**	**—**	**4**	**(39)**
	(293)	**—**	**—**	**—**	**—**	**(95)**	**(388)**
Balance as at December 31, 2022	**121**	**(35)**	**(1,137)**	**4,348**	**5**	**218**	**3,520**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2021	(1,326)	5	(215)	568	66	(499)	(1,401)
Other comprehensive income/(loss) retained in AOCI	238	(5)	49	(492)	(12)	520	298
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	296	—	—	—	—	—	296
Commodity contracts[5]	1	—	—	—	—	—	1
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	2	—	—	—	—	—	2
Equity investment disposal	—	—	—	—	(66)	—	(66)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	28	28
Other	17	—	—	(20)	3	—	—
	559	(5)	49	(512)	(75)	548	564
Tax impact							
Income tax on amounts retained in AOCI	(61)	—	—	—	—	(126)	(187)
Income tax on amounts reclassified to earnings	(69)	—	—	—	4	(7)	(72)
	(130)	—	—	—	4	(133)	(259)
Balance as at December 31, 2021	(897)	—	(166)	56	(5)	(84)	(1,096)

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2020	(1,073)	—	(317)	1,396	67	(345)	(272)
Other comprehensive income/(loss) retained in AOCI	(591)	5	115	(828)	(2)	(221)	(1,522)
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	253	—	—	—	—	—	253
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	(2)	—	—	—	—	—	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	17	17
	(335)	5	115	(828)	(2)	(204)	(1,249)
Tax impact							
Income tax on amounts retained in AOCI	140	—	(13)	—	1	54	182
Income tax on amounts reclassified to earnings	(58)	—	—	—	—	(4)	(62)
	82	—	(13)	—	1	50	120
Balance as at December 31, 2020	(1,326)	5	(215)	568	66	(499)	(1,401)

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.
3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
4 These components are included in the computation of net periodic benefit (credit)/cost and are reported within Other income/(expense) in the Consolidated Statements of Earnings.
5 Reported within Transportation and other services revenues, Commodity sales, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying cash flow, fair value and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar-denominated investments and subsidiaries using foreign currency derivatives and US dollar-denominated debt.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps. These hedges have an average fixed rate of 4.0%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2022, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

Commodity Price Risk
Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS
We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts in the event of the specific circumstances described above. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2022	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**—**	**—**	**46**	**46**	**(41)**	**5**
Interest rate contracts	**649**	**—**	**11**	**660**	**—**	**660**
Commodity contracts	**—**	**—**	**302**	**302**	**(182)**	**120**
Other contracts	**—**	**—**	**7**	**7**	**—**	**7**
	649	**—**	**366**	**1,015**	**(223)**	**792**
Deferred amounts and other assets						
Foreign exchange contracts	**—**	**156**	**153**	**309**	**(138)**	**171**
Interest rate contracts	**254**	**—**	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**—**	**61**	**61**	**(25)**	**36**
Other contracts	**1**	**—**	**2**	**3**	**—**	**3**
	255	**156**	**216**	**627**	**(163)**	**464**
Accounts payable and other						
Foreign exchange contracts	**—**	**(42)**	**(524)**	**(566)**	**41**	**(525)**
Commodity contracts	**(48)**	**—**	**(284)**	**(332)**	**182**	**(150)**
	(48)	**(42)**	**(808)**	**(898)**	**223**	**(675)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(1,116)**	**(1,116)**	**138**	**(978)**
Interest rate contracts	**(3)**	**—**	**(1)**	**(4)**	**—**	**(4)**
Commodity contracts	**(37)**	**—**	**(133)**	**(170)**	**25**	**(145)**
	(40)	**—**	**(1,250)**	**(1,290)**	**163**	**(1,127)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**—**	**114**	**(1,441)**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**900**	**—**	**10**	**910**	**—**	**910**
Commodity contracts	**(85)**	**—**	**(54)**	**(139)**	**—**	**(139)**
Other contracts	**1**	**—**	**9**	**10**	**—**	**10**
	816	**114**	**(1,476)**	**(546)**	**—**	**(546)**

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	—	—	259	259	(41)	218
Interest rate contracts	64	—	—	64	—	64
Commodity contracts	—	—	204	204	(129)	75
Other contracts	—	—	2	2	—	2
	64	—	465	529	(170)	359
Deferred amounts and other assets						
Foreign exchange contracts	—	—	240	240	(61)	179
Interest rate contracts	88	—	—	88	(1)	87
Commodity contracts	—	—	29	29	(13)	16
Other contracts	—	—	3	3	—	3
	88	—	272	360	(75)	285
Accounts payable and other						
Foreign exchange contracts	(15)	(112)	(176)	(303)	41	(262)
Interest rate contracts	(150)	—	—	(150)	—	(150)
Commodity contracts	(14)	—	(250)	(264)	129	(135)
	(179)	(112)	(426)	(717)	170	(547)
Other long-term liabilities						
Foreign exchange contracts	—	—	(423)	(423)	61	(362)
Interest rate contracts	(1)	—	(23)	(24)	1	(23)
Commodity contracts	(17)	—	(67)	(84)	13	(71)
	(18)	—	(513)	(531)	75	(456)
Total net derivative asset/(liability)						
Foreign exchange contracts	(15)	(112)	(100)	(227)	—	(227)
Interest rate contracts	1	—	(23)	(22)	—	(22)
Commodity contracts	(31)	—	(84)	(115)	—	(115)
Other contracts	—	—	5	5	—	5
	(45)	(112)	(202)	(359)	—	(359)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

	2022							2021
As at December 31,	2023	2024	2025	2026	2027	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**655**	**1,000**	**500**	**—**	**—**	**—**	**2,155**	2,508
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**8,297**	**6,386**	**4,613**	**4,121**	**2,837**	**1,356**	**27,610**	25,427
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**29**	**30**	**30**	**28**	**32**	**—**	**149**	177
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**92**	**91**	**86**	**85**	**81**	**262**	**697**	801
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**84,800**	**—**	**—**	**—**	**84,800**	72,500
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**8,698**	**538**	**30**	**26**	**25**	**39**	**9,356**	597
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**5,496**	**1,766**	**589**	**—**	**—**	**—**	**7,851**	5,279
Equity contracts *(millions of Canadian dollars)*	**37**	**31**	**12**	**—**	**—**	**—**	**80**	67
Commodity contracts - natural gas *(billions of cubic feet)*	**52**	**25**	**15**	**1**	**—**	**—**	**93**	199
Commodity contracts - crude oil *(millions of barrels)*	**16**	**—**	**—**	**—**	**—**	**—**	**16**	12
Commodity contracts - power *(megawatt per hour (MW/H))*	**26**	**(25)**	**(44)**	**—**	**—**	**—**	**(14)** [1]	(43) [1]

1 Total is an average net purchase/(sell) of power.

Fair Value Derivatives

For foreign exchange derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. The offsetting loss or gain on the hedged item attributable to the hedged risk is included in Other income/(expense) in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

Year ended December 31,	2022	2021
(millions of Canadian dollars)		
Unrealized gain on derivative	**262**	8
Unrealized loss on hedged item	**(254)**	(15)
Realized loss on derivative	**(110)**	(41)
Realized gain on hedged item	**85**	45

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	2022	2021	2020
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**3**	(29)	(1)
Interest rate contracts	**1,151**	252	(595)
Commodity contracts	**(53)**	(28)	2
Other contracts	**(4)**	1	(3)
Fair value hedges			
Foreign exchange contracts	**(35)**	(5)	5
Net investment hedges			
Foreign exchange contracts	**—**	—	13
	1,062	191	(579)
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**13**	5	5
Interest rate contracts[2]	**186**	296	253
Commodity contracts[3]	**—**	1	—
Other contracts[3]	**4**	2	(2)
	203	304	256

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.

2 Reported within Interest expense in the Consolidated Statements of Earnings.

3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a gain of $67 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 36 months as at December 31, 2022.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(1,344)**	92	902
Interest rate contracts[2]	**10**	2	(25)
Commodity contracts[3]	**50**	71	(114)
Other contracts[4]	**4**	8	(7)
Total unrealized derivative fair value gain/(loss), net	**(1,280)**	173	756

1 For the respective annual periods, reported within Transportation and other services revenue (2022 - $238 million loss; 2021 - $98 million gain; 2020 - $533 million gain) and Other income/(expense) (2022 - $1,106 million loss; 2021 - $6 million loss; 2020 - $369 million gain) in the Consolidated Statements of Earnings.

2 Reported as an increase within Interest expense in the Consolidated Statements of Earnings.

3 For the respective annual periods, reported within Transportation and other services revenue (2022 - $13 million gain; 2021 - $9 million gain; 2020 - $2 million loss), Commodity sales (2022 - $89 million gain; 2021 - $160 million gain; 2020 - $321 million loss), Commodity costs (2022 - $102 million loss; 2021 - $105 million loss; 2020 - $207 million gain) and Operating and administrative expense (2022 - $50 million gain; 2021 - $7 million gain; 2020 - $2 million gain) in the Consolidated Statements of Earnings.

4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK
Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2022. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities.

CREDIT RISK
Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Canadian financial institutions	**644**	424
US financial institutions	**277**	130
European financial institutions	**334**	181
Asian financial institutions	**224**	30
Other[1]	**105**	122
	1,584	887

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2022, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2022 and December 31, 2021.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas, credit risk is mitigated by the utility's large and diversified customer base and the ability to recover an estimate for expected credit losses through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our financial instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations, US and Canadian treasury bills, investments in exchange-traded equity funds held by our captive insurance subsidiaries, as well as restricted long-term investments in Canadian equity securities that are held in trust in accordance with the CER's regulatory requirements under the LMCI.

Level 2

Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the financial instrument. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our long-term debt, investments in debt securities held by our captive insurance subsidiaries, and restricted long-term investments in Canadian government bonds held in accordance with the CER's regulatory requirements under the LMCI as Level 2. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor. When possible, the fair value of our restricted long-term investments is based on quoted market prices for similar instruments and, if not available, based on broker quotes.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps, as well as physical forward commodity contracts. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

We have categorized our derivative assets and liabilities measured at fair value as follows:

December 31, 2022	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**46**	**—**	**46**
Interest rate contracts	**—**	**660**	**—**	**660**
Commodity contracts	**65**	**90**	**147**	**302**
Other contracts	**—**	**7**	**—**	**7**
	65	**803**	**147**	**1,015**
Long-term derivative assets				
Foreign exchange contracts	**—**	**309**	**—**	**309**
Interest rate contracts	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**17**	**44**	**61**
Other contracts	**—**	**3**	**—**	**3**
	—	**583**	**44**	**627**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(566)**	**—**	**(566)**
Commodity contracts	**(60)**	**(77)**	**(195)**	**(332)**
	(60)	**(643)**	**(195)**	**(898)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,116)**	**—**	**(1,116)**
Interest rate contracts	**—**	**(4)**	**—**	**(4)**
Commodity contracts	**—**	**(38)**	**(132)**	**(170)**
	—	**(1,158)**	**(132)**	**(1,290)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**—**	**910**	**—**	**910**
Commodity contracts	**5**	**(8)**	**(136)**	**(139)**
Other contracts	**—**	**10**	**—**	**10**
	5	**(415)**	**(136)**	**(546)**

December 31, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	259	—	259
Interest rate contracts	—	64	—	64
Commodity contracts	38	71	95	204
Other contracts	—	2	—	2
	38	396	95	529
Long-term derivative assets				
Foreign exchange contracts	—	240	—	240
Interest rate contracts	—	88	—	88
Commodity contracts	—	21	8	29
Other contracts	—	3	—	3
	—	352	8	360
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(303)	—	(303)
Interest rate contracts	—	(150)	—	(150)
Commodity contracts	(52)	(66)	(146)	(264)
	(52)	(519)	(146)	(717)
Long-term derivative liabilities				
Foreign exchange contracts	—	(423)	—	(423)
Interest rate contracts	—	(24)	—	(24)
Commodity contracts	—	(19)	(65)	(84)
	—	(466)	(65)	(531)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(227)	—	(227)
Interest rate contracts	—	(22)	—	(22)
Commodity contracts	(14)	7	(108)	(115)
Other contracts	—	5	—	5
	(14)	(237)	(108)	(359)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2022	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(35)**	**Forward gas price**	**4.57**	**34.56**	**6.25**	**$/mmbtu[2]**
Crude	**(4)**	**Forward crude price**	**71.10**	**105.22**	**83.26**	**$/barrel**
Power	**(71)**	**Forward power price**	**36.63**	**364.00**	**103.30**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(41)**	**Forward gas price**	**1.67**	**33.89**	**6.00**	**$/mmbtu[2]**
Crude	**(2)**	**Forward crude price**	**64.43**	**116.60**	**86.25**	**$/barrel**
Power	**17**	**Forward power price**	**30.49**	**183.88**	**72.48**	**$/MW/H**
	(136)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(108)**	(191)
Total gain/(loss)		
Included in earnings[1]	**6**	(39)
Included in OCI	**(54)**	(29)
Settlements	**20**	151
Level 3 net derivative liability at end of period	**(136)**	(108)

1 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

There were no transfers into or out of Level 3 as at December 31, 2022 or 2021.

NET INVESTMENT HEDGES

We currently have designated a portion of our US dollar-denominated debt as a hedge of our net investment in US dollar-denominated investments and subsidiaries.

During the years ended December 31, 2022 and 2021, we recognized an unrealized foreign exchange loss of $954 million and gain of $49 million, respectively, on the translation of US dollar-denominated debt, in OCI. No unrealized gains or losses on the change in fair value of our outstanding foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. No realized gains or losses associated with the settlement of foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. During the years ended December 31, 2022 and 2021, we recognized a realized loss of $21 million and nil, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $102 million and $52 million as at December 31, 2022 and 2021, respectively.

As at December 31, 2022, the fair value of short- and long-term investments in equity funds and debt securities held by our captive insurance subsidiaries was $145 million and $488 million, respectively (2021 - $14 million and $290 million, respectively). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, and are recorded in Accounts receivable and other and Long-term investments, respectively, in the Consolidated Statements of Financial Position. There were unrealized holding losses in equity funds and debt securities of $26 million for the year ended December 31, 2022 (2021 - losses of $12 million).

As at December 31, 2022 and 2021, our long-term debt had a carrying value of $79.3 billion and $74.4 billion, respectively, before debt issuance costs and a fair value of $73.5 billion and $82.0 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2022 and 2021, the non-current notes receivable had a carrying value of $752 million and $954 million, respectively, which also approximates their fair value.

The fair value of financial assets and liabilities other than derivative instruments, long-term investments, restricted long-term investments, long-term debt and non-current notes receivable described above approximate their carrying value due to the short period to maturity.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes	**4,542**	7,729	4,190
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**681**	1,159	629
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**108**	228	288
Foreign and other statutory rate differentials[2]	**295**	134	(53)
Effects of rate-regulated accounting[3]	**(122)**	(139)	(145)
Foreign allowable interest deductions	**—**	—	(4)
Part VI.1 tax, net of federal Part I deduction[4]	**76**	73	76
US Minimum Tax[5]	**107**	—	44
Non-taxable portion of gain on sale of investment[6]	**—**	(23)	—
Valuation allowance	**6**	5	(6)
Accounting impairment of non-deductible goodwill[7]	**370**	—	—
Noncontrolling interests[8]	**9**	(17)	(8)
Other[9]	**74**	(5)	(47)
Income tax expense	**1,604**	1,415	774
Effective income tax rate	**35.3%**	18.3%	18.5%

1 *The change in provincial and state income taxes from 2021 to 2022 reflects the decrease in earnings from Canadian operations and the effect of the reduction in the Pennsylvania corporate income tax rate in the US, partially offset by the increase in earnings from US operations before the non-deductible goodwill impairment relating to the Gas Transmission reporting unit in combination with state tax apportionment changes. Refer to* Note 16 - Goodwill.

2 *The change in foreign and other statutory rate differentials from 2021 to 2022 reflects the increase in earnings from US operations, before the goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.

3 *The amount in 2022 relates to the federal component of the tax impact relating to the 2022 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.

4 *Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.*

5 *There was no US Minimum Tax in 2021 as a result of tax losses from bonus tax depreciation.*

6 *The amount in 2021 relates to the federal impact of the gain on sale of the investment in Noverco.*

7 *The amount in 2022 relates to the federal impact of the non-deductible goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.

8 *The amount in 2022 includes the federal tax impact of an impairment to Magic Valley attributable to noncontrolling interests. Refer to* Note 11 - Property, Plant and Equipment.

9 *The amount in 2022 includes the federal component of the tax impact relating to the 2021 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**583**	3,399	2,789
US	**2,865**	3,336	407
Other	**1,094**	994	994
	4,542	7,729	4,190
Current income taxes			
Canada	**360**	162	165
US	**201**	80	64
Other	**86**	82	98
	647	324	327
Deferred income taxes			
Canada	**(358)**	344	378
US	**1,309**	741	66
Other	**6**	6	3
	957	1,091	447
Income tax expense	**1,604**	1,415	774

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(9,096)**	(8,721)
Investments	**(7,099)**	(6,097)
Regulatory assets	**(1,291)**	(1,245)
Pension and OPEB plans	**(30)**	—
Other	**(46)**	(208)
Total deferred income tax liabilities	**(17,562)**	(16,271)
Deferred income tax assets		
Financial instruments	**456**	315
Pension and OPEB plans	**—**	110
Loss carryforwards	**2,259**	3,081
Other	**1,753**	1,648
Total deferred income tax assets	**4,468**	5,154
Less valuation allowance	**(215)**	(84)
Total deferred income tax assets, net	**4,253**	5,070
Net deferred income tax liabilities	**(13,309)**	(11,201)
Presented as follows:		
Total deferred income tax assets	**472**	488
Total deferred income tax liabilities	**(13,781)**	(11,689)
Net deferred income tax liabilities	**(13,309)**	(11,201)

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2022, we recognized the benefit of unused tax loss carryforwards of $2.1 billion (2021 - $1.9 billion) in Canada which expire in 2030 and beyond.

As at December 31, 2022, we recognized the benefit of unused tax loss carryforwards of $8.1 billion (2021 - $11.0 billion) in the US. Unused tax loss carryforwards of $0.2 billion (2021 - $3.5 billion) begin to expire in 2023, and unused tax loss carryforwards of $7.9 billion (2021 - $7.5 billion) have no expiration.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $8.0 billion and $4.3 billion for the periods ended December 31, 2022 and 2021, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities applicable to such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Québec). We are open to examination by Canadian tax authorities for the 2015 to 2022 tax years and by US tax authorities for the 2019 to 2022 tax years. We are currently under examination for income tax matters in Canada for the 2016 to 2019 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2022**	2021
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**76**	121
Gross increases for tax positions of current year	**—**	1
Gross decreases for tax positions of prior year	**(17)**	(26)
Change in translation of foreign currency	**1**	(1)
Lapses of statute of limitations	**(5)**	(19)
Unrecognized tax benefits at end of year	**55**	76

The unrecognized tax benefits as at December 31, 2022, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2022 and 2021 were a $1 million expense and $5 million recovery, respectively. As at December 31, 2022 and 2021, interest and penalties of $13 million and $12 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and US contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian pension plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The US pension plans provide defined benefit pension benefits to our US employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the US.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension plans:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,600**	4,855	**1,184**	1,243
Service cost	**131**	139	**43**	44
Interest cost	**127**	101	**24**	17
Participant contributions	**29**	28	**—**	—
Actuarial gain[1]	**(1,069)**	(329)	**(201)**	(21)
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**77**	(11)
Other	**(1)**	—	**(4)**	(4)
Projected benefit obligation at end of year[2]	**3,630**	4,600	**1,029**	1,184
Change in plan assets				
Fair value of plan assets at beginning of year	**4,536**	4,077	**1,160**	1,062
Actual return/(loss) on plan assets	**(235)**	505	**(64)**	151
Employer contributions[3]	**91**	120	**4**	43
Participant contributions	**29**	28	**—**	—
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**78**	(8)
Other	**—**	—	**(4)**	(4)
Fair value of plan assets at end of year[4]	**4,234**	4,536	**1,080**	1,160
Overfunded/(underfunded) status at end of year	**604**	(64)	**51**	(24)
Presented as follows:				
Deferred amounts and other assets	**764**	250	**141**	98
Accounts payable and other	**(9)**	(9)	**(5)**	(4)
Other long-term liabilities	**(151)**	(305)	**(85)**	(118)
	604	(64)	**51**	(24)

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.

2 The accumulated benefit obligation for our Canadian pension plans was $3.4 billion and $4.3 billion as at December 31, 2022 and 2021, respectively. The accumulated benefit obligation for our US pension plans was $1.0 billion and $1.1 billion as at December 31, 2022 and 2021, respectively.

3 Lower employer contributions in 2022 compared to 2021 primarily due to more plans in an overfunded status.

4 Assets in the amount of $10 million (2021 - $13 million) and $58 million (2021 - $84 million), related to our Canadian and US non-registered supplemental pension plan obligations, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**360**	440	**89**	115
Fair value of plan assets	**218**	247	**—**	—

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Projected benefit obligation	**377**	1,272	**90**	121
Fair value of plan assets	**218**	1,020	**—**	—

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our pension plans are as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(64)**	226	**40**	92
Prior service (credit)/cost	**—**	—	**1**	(1)
Total amount recognized in AOCI[1]	**(64)**	226	**41**	91

1 Excludes amounts related to CTA.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

	Canada			US		
Year ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**131**	139	148	**43**	44	44
Interest cost[1]	**127**	101	128	**24**	17	31
Expected return on plan assets[1]	**(295)**	(252)	(260)	**(85)**	(73)	(88)
Amortization/settlement of net actuarial loss[1]	**8**	54	42	**—**	11	1
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(2)**	—	(1)
Net periodic benefit (credit)/cost	**(29)**	42	58	**(20)**	(1)	(13)
Defined contribution benefit cost	**10**	7	6	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**(19)**	49	64	**(20)**	(1)	(13)
Amount recognized in OCI:						
Amortization/settlement of net actuarial loss	**(2)**	(25)	(21)	**—**	(11)	(1)
Amortization/curtailment of prior service credit	**—**	—	—	**2**	—	1
Net actuarial (gain)/loss arising during the year	**(288)**	(291)	118	**(52)**	(99)	100
Total amount recognized in OCI	**(290)**	(316)	97	**(50)**	(110)	100
Total amount recognized in Comprehensive income	**(309)**	(267)	161	**(70)**	(111)	87

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			US		
	2022	2021	2020	**2022**	2021	2020
Projected benefit obligation						
Discount rate	**5.1 %**	3.2 %	2.6 %	**4.9 %**	2.6 %	2.2 %
Rate of salary increase	**2.9 %**	2.9 %	2.3 %	**2.8 %**	2.8 %	2.7 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.3 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.0 %	**2.6 %**	2.2 %	3.0 %
Rate of return on plan assets	**6.6 %**	6.2 %	6.8 %	**7.4 %**	7.3 %	7.9 %
Rate of salary increase	**2.9 %**	2.3 %	3.2 %	**2.8 %**	2.7 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.5 %

OTHER POSTRETIREMENT BENEFIT PLANS

We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**274**	321	**173**	254
Service cost	**4**	6	**1**	1
Interest cost	**7**	7	**3**	3
Participant contributions	**—**	—	**6**	8
Actuarial gain[1]	**(66)**	(51)	**(37)**	(69)
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**11**	(3)
Other	**—**	—	**—**	1
Accumulated postretirement benefit obligation at end of year	**211**	274	**136**	173
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**201**	188
Actual return/(loss) on plan assets	**—**	—	**(21)**	22
Employer contributions	**8**	9	**7**	6
Participant contributions	**—**	—	**6**	8
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**13**	(3)
Other	**—**	—	**—**	2
Fair value of plan assets at end of year	**—**	—	**185**	201
Overfunded/(underfunded) status at end of year	**(211)**	(274)	**49**	28
Presented as follows:				
Deferred amounts and other assets	**—**	—	**75**	71
Accounts payable and other	**(12)**	(12)	**—**	—
Other long-term liabilities	**(199)**	(262)	**(26)**	(43)
	(211)	(274)	**49**	28

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.

Certain of our OPEB plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**211**	274	**76**	94
Fair value of plan assets	**—**	—	**50**	51

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial gain	**(101)**	(35)	**(102)**	(104)
Prior service credit	**(1)**	(1)	**(30)**	(37)
Total amount recognized in AOCI[1]	**(102)**	(36)	**(132)**	(141)

1 Excludes amounts related to CTA.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

	Canada			US		
Year ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**4**	6	5	**1**	1	2
Interest cost[1]	**7**	7	8	**3**	3	7
Expected return on plan assets[1]	**—**	—	—	**(12)**	(10)	(12)
Amortization/settlement of net actuarial gain[1]	**(1)**	—	(1)	**(6)**	(1)	(1)
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(7)**	(7)	(2)
Net periodic benefit (credit)/cost recognized in Earnings	**10**	13	12	**(21)**	(14)	(6)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**1**	—	1	**6**	1	1
Amortization/curtailment of prior service credit	**—**	—	—	**7**	7	2
Net actuarial (gain)/loss arising during the year	**(67)**	(50)	21	**(4)**	(80)	15
Prior service credit	**—**	—	—	**—**	—	(33)
Total amount recognized in OCI	**(66)**	(50)	22	**9**	(72)	(15)
Total amount recognized in Comprehensive income	**(56)**	(37)	34	**(12)**	(86)	(21)

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			US		
	2022	2021	2020	**2022**	2021	2020
Accumulated postretirement benefit obligation						
Discount rate	**5.3 %**	3.2 %	2.6 %	**4.9 %**	2.4 %	2.0 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.1 %	**2.4 %**	2.0 %	2.8 %
Rate of return on plan assets	**N/A**	N/A	N/A	**6.0 %**	6.0 %	6.7 %

Assumed Health Care Cost Trend Rates
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		US[1]	
	2022	2021	**2022**	2021
Health care cost trend rate assumed for next year	**4.0 %**	4.0 %	**4.7 %**	7.0 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0 %**	4.0 %	**3.3 %**	4.5 %
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2021 - 2045**	2037

1 In addition, under the Enbridge Employee Services, Inc., Health Reimbursement Account Plan, health care costs will increase by 5.0% every three years.

PLAN ASSETS
We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

	Canada			US		
	Target	December 31,		**Target**	December 31,	
Asset Category	**Allocation**	**2022**	2021	**Allocation**	**2022**	2021
Equity securities	**43.8 %**	**38.2 %**	46.7 %	**45.0 %**	**38.3 %**	52.5 %
Fixed income securities	**28.4 %**	**31.7 %**	29.8 %	**20.0 %**	**20.5 %**	18.4 %
Alternatives[1]	**27.8 %**	**30.1 %**	23.5 %	**35.0 %**	**41.2 %**	29.1 %

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

Pension Plans

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2022								
Cash and cash equivalents	**272**	**—**	**—**	**272**	**13**	**—**	**—**	**13**
Equity securities								
Canada	**—**	**355**	**—**	**355**	**—**	**—**	**—**	**—**
Global	**—**	**1,263**	**—**	**1,263**	**—**	**414**	**—**	**414**
Fixed income securities								
Government	**201**	**435**	**—**	**636**	**—**	**87**	**—**	**87**
Corporate	**—**	**433**	**—**	**433**	**—**	**121**	**—**	**121**
Alternatives[4]	**—**	**—**	**1,291**	**1,291**	**—**	**—**	**445**	**445**
Forward currency contracts	**—**	**(16)**	**—**	**(16)**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**473**	**2,470**	**1,291**	**4,234**	**13**	**622**	**445**	**1,080**
December 31, 2021								
Cash and cash equivalents	180	—	—	180	10	—	—	10
Equity securities								
Canada	198	228	—	426	—	—	—	—
US	1	—	—	1	—	—	—	—
Global	—	1,693	—	1,693	—	609	—	609
Fixed income securities								
Government	258	459	—	717	—	86	—	86
Corporate	—	453	—	453	—	118	—	118
Alternatives[4]	—	—	1,064	1,064	—	—	337	337
Forward currency contracts	—	2	—	2	—	—	—	—
Total pension plan assets at fair value	637	2,835	1,064	4,536	10	813	337	1,160

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		US	
December 31,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Balance at beginning of year	**1,064**	912	**337**	289
Unrealized and realized gains	**155**	77	**78**	38
Purchases and settlements, net	**72**	75	**30**	10
Balance at end of year	**1,291**	1,064	**445**	337

OPEB Plans

The following table summarizes the fair value of plan assets for our US funded OPEB plans recorded at each fair value hierarchy level:

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2022				
Cash and cash equivalents	**2**	**—**	**—**	**2**
Equity securities				
US	**—**	**34**	**—**	**34**
Global	**—**	**62**	**—**	**62**
Fixed income securities				
Government	**46**	**5**	**—**	**51**
Corporate	**—**	**8**	**—**	**8**
Alternatives[4]	**—**	**—**	**28**	**28**
Total OPEB plan assets at fair value	**48**	**109**	**28**	**185**
December 31, 2021				
Cash and cash equivalents	4	—	—	4
Equity securities				
US	—	39	—	39
Global	—	75	—	75
Fixed income securities				
Government	47	6	—	53
Corporate	—	8	—	8
Alternatives[4]	—	—	22	22
Total OPEB plan assets at fair value	51	128	22	201

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives includes investments in private debt, private equity, infrastructure and real estate.

Changes in the net fair value of US funded OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2022**	2021
(millions of Canadian dollars)		
Balance at beginning of year	**22**	22
Unrealized and realized gains	**4**	2
Purchases and settlements, net	**2**	(2)
Balance at end of year	**28**	22

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2023	2024	2025	2026	2027	2028-2032
(millions of Canadian dollars)						
Pension						
Canada	204	210	216	221	226	1,208
US	88	87	87	88	90	424
OPEB						
Canada	12	12	13	13	13	68
US	16	15	14	13	12	49

EXPECTED EMPLOYER CONTRIBUTIONS

In 2023, we expect to contribute approximately $29 million and $5 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6.0% of eligible pay per pay period. For the year ended December 31, 2022, pre-tax employer matching contribution costs were $30 million ($27 million in each of 2021 and 2020).

27. LEASES

LESSEE

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 1 month to 24 years as at December 31, 2022.

For the years ended December 31, 2022, 2021 and 2020, we incurred operating lease expenses of $118 million, $95 million and $107 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2022, 2021 and 2020, operating lease payments to settle lease liabilities were $123 million, $118 million and $133 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	December 31, 2022	December 31, 2021
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**680**	645
Operating lease liabilities - current[3]	**87**	92
Operating lease liabilities - long-term[3]	**677**	612
Total operating lease liabilities	**764**	704
Finance leases		
Finance lease right-of-use assets, net[4]	**62**	49
Finance lease liabilities - current[5]	**17**	13
Finance lease liabilities - long-term[3]	**39**	33
Total finance lease liabilities	**56**	46
Weighted average remaining lease term		
Operating leases	**12 years**	12 years
Finance leases	**5 years**	7 years
Weighted average discount rate		
Operating leases	**4.2 %**	4.1 %
Finance leases	**4.4 %**	3.8 %

1 Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2022 were $47 million (December 31, 2021 - $51 million), $5 million (December 31, 2021 - $5 million) and $43 million (December 31, 2021 - $47 million), respectively.

2 Operating lease ROU assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.

3 Current operating lease liabilities and long-term operating and finance lease liabilities are reported under Accounts payable and other and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.

4 Finance lease ROU assets are reported under Property, plant and equipment, net in the Consolidated Statements of Financial Position.

5 Current finance lease liabilities are reported under Current portion of long-term debt in the Consolidated Statements of Financial Position.

As at December 31, 2022, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	Finance leases
(millions of Canadian dollars)		
2023	**109**	**19**
2024	**110**	**16**
2025	**104**	**8**
2026	**90**	**8**
2027	**82**	**1**
Thereafter	**489**	**10**
Total undiscounted lease payments	**984**	**62**
Less imputed interest	**(220)**	**(6)**
Total	**764**	**56**

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 1 month to 29 years as at December 31, 2022.

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating lease income	**266**	263	265
Variable lease income	**321**	333	361
Total lease income[1]	**587**	596	626

1 Lease income is recorded under Transportation and other services in the Consolidated Statements of Earnings.

As at December 31, 2022, our future lease payments to be received under operating lease contracts where we are the lessor are as follows:

	Operating leases
(millions of Canadian dollars)	
2023	**227**
2024	**215**
2025	**204**
2026	**198**
2027	**201**
Thereafter	**1,832**
Future lease payments	**2,877**

28. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Gain/(loss) on dispositions	**(12)**	319	(17)
Realized foreign currency gain/(loss)	**92**	126	(10)
Unrealized foreign currency gain/(loss)	**(1,094)**	160	191
Net defined pension and OPEB credit	**239**	150	148
Other	**186**	224	(74)
	(589)	979	238

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Accounts receivable and other	**(967)**	(1,228)	1,546
Accounts receivable from affiliates	**17**	(38)	8
Inventory	**(599)**	(118)	(254)
Deferred amounts and other assets	**1**	(195)	(586)
Accounts payable and other	**1,100**	87	(770)
Accounts payable to affiliates	**16**	52	1
Interest payable	**58**	43	31
Other long-term liabilities	**362**	(69)	117
	(12)	(1,466)	93

30. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

We provide transportation services to several significantly influenced investees which we record as transportation and other services revenue. We also purchase and sell natural gas and crude oil with several of our significantly influenced investees. These revenues and costs are recorded as commodity sales and commodity costs. We contract for firm transportation services to meet our annual natural gas supply requirements which we record as gas distribution costs.

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Transportation and other revenues	**185**	237	219
Commodity sales	**51**	20	21
Operating and administrative[1]	**503**	380	338
Commodity costs[2]	**778**	790	518
Gas distribution costs	**136**	131	135

1 *During the years ended December 31, 2022, 2021 and 2020, we had Operating and administrative costs from the Seaway Crude Pipeline System of $495 million, $389 million and $342 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business.*

2 *During the years ended December 31, 2022, 2021 and 2020, we had Commodity costs from Aux Sable Canada LP of $571 million, $447 million and $91 million, respectively.*

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2022, amounts receivable from affiliates include a series of loans totaling $752 million (2021 - $954 million), which require quarterly or semi-annual interest payments at annual interest rates ranging from 3% to 8%. Interest income recognized from these notes totaled $30 million, $39 million and $44 million for the years ended December 31, 2022, 2021 and 2020, respectively. The amounts receivable from affiliates are included in Deferred amounts and other assets in the Consolidated Statements of Financial position.

31. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2022, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	78,742	6,024	8,220	6,051	3,730	10,344	44,373
Purchase of services, pipe and other materials, including transportation[2]	10,661	3,553	1,513	1,070	1,001	767	2,757
Maintenance agreements[3]	536	53	53	53	53	55	269
Right-of-ways commitments	1,474	45	45	46	46	46	1,246
Total	91,413	9,675	9,831	7,220	4,830	11,212	48,645

1 *Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and fair value adjustment. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.*

2 *Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.*

3 *Consists primarily of maintenance service contracts for our wind and solar assets.*

ENVIRONMENTAL

We are subject to various Canadian and US federal, provincial/state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and its affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

AUX SABLE

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim.

On November 27, 2019, the counterparty filed an amended amended claim providing further particulars of its claim against Aux Sable, increasing its damages claimed, and adding defendants Aux Sable Liquid Products Inc. and Aux Sable Extraction LLC (general partners of the previously existing defendants). Aux Sable filed an amended Statement of Defence responding to the amended amended claim on January 31, 2020.

While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

OTHER LITIGATION
We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS
We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

INSURANCE
We maintain a comprehensive insurance program for us, our operating subsidiaries and certain equity investments. This program includes insurance coverage in types and amounts and is subject to certain deductibles, terms, exclusions and conditions that are generally consistent with coverage considered customary for our industry, however insurance does not cover all events in all circumstances. We self-insure a significant portion of expected losses relating to certain insurance property and casualty risk exposures in the US and Canada through our wholly-owned captive insurance subsidiaries.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among entities on an equitable basis based on an insurance allocation agreement we have entered into with us and other subsidiaries. Insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods.

32. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2022, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2022					
Operating revenues	**15,097**	**13,215**	**11,573**	**13,424**	**53,309**
Operating income/(loss)	**2,420**	**1,520**	**1,778**	**(540)**	**5,178**
Earnings/(loss)	**2,057**	**607**	**1,383**	**(1,109)**	**2,938**
Earnings/(loss) attributable to controlling interests	**2,029**	**595**	**1,362**	**(983)**	**3,003**
Earnings/(loss) attributable to common shareholders	**1,927**	**450**	**1,279**	**(1,067)**	**2,589**
Earnings/(loss) per common share					
Basic	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
Diluted	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
2021					
Operating revenues	12,187	10,948	11,466	12,470	47,071
Operating income	2,548	1,816	1,388	2,053	7,805
Earnings	2,014	1,521	814	1,965	6,314
Earnings attributable to controlling interests	1,992	1,484	780	1,933	6,189
Earnings attributable to common shareholders	1,900	1,394	682	1,840	5,816
Earnings per common share					
Basic	0.94	0.69	0.34	0.91	2.87
Diluted	0.94	0.69	0.34	0.91	2.87

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2022

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2022 and 2021 items and year-over-year comparisons between 2022 and 2021. For discussion of 2020 items and year-over-year comparisons between 2021 and 2020, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2021.

RECENT DEVELOPMENTS

Chair of the Board and CEO Appointments

Pamela L. Carter was appointed Chair of the Board of Directors (the Board) effective January 1, 2023. Gregory L. Ebel was appointed as President and Chief Executive Officer (CEO) effective the same date. Mr. Ebel succeeds retiring President and CEO, Al Monaco. To support Mr. Ebel through the transition, Mr. Monaco will serve as an advisor until June 30, 2023. Mr. Ebel will continue as a member of the Board. Ms. Carter has served as a director of the Board since 2017 and with Spectra Energy Corp since 2007. Most recently she has served as Chair of the Human Resources & Compensation Committee of the Board, as a member of the Sustainability and Safety & Reliability Committees and as a former Chair of the Governance Committee.

ASSET TRANSACTIONS

Joint Venture Merger Transaction to Advance US Gulf Coast Oil Strategy

On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream LLC, holding both Enbridge Inc.'s (Enbridge) and P66's indirect ownership interests in Gray Oak Pipeline, LLC (Gray Oak) and DCP Midstream, LP (DCP), as well as an agreement to realign our respective economic and governance interests in the underlying business operations. Our effective economic interest in Gray Oak has increased to 58.5% from 22.8%, and we will assume operatorship of Gray Oak in the second quarter of 2023. Simultaneously, our effective economic interest in DCP has been reduced to 13.2% from 28.3%. We received approximately $522 million (US$404 million) in cash proceeds and recorded an accounting gain of approximately $1.1 billion (US$832 million) in the Consolidated Statements of Earnings as a result of the transaction.

Acquisition of Tri Global Energy, LLC

On September 27, 2022, we acquired Tri Global Energy, LLC (TGE), a leading United States (US) renewable power project developer, for approximately US$270 million in cash and assumed debt. The acquisition of TGE enhances our renewable power platform and further builds on our inventory of North American growth opportunities for wind and solar projects.

Athabasca Indigenous Investments Partnership

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Métis communities, in which Aii acquired an 11.6% non-operating interest in seven Regional Oil Sands pipelines in northern Alberta for $1.1 billion.

Increased Ownership in Cactus II Pipeline

On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II Pipeline from Western Midstream Partners, L.P., for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%. Plains All-American Pipeline, L.P. remains the operator with a 70% ownership stake.

Woodfibre LNG Limited Partnership Agreement

On November 29, 2022, we finalized our partnership agreement with Pacific Energy Corporation Limited. We acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre LNG Limited Partnership (Woodfibre), which will operate the 2.1 million tonnes per annum Woodfibre LNG facility located in Squamish, British Columbia (BC). The facility, via an interconnect with FortisBC Energy Inc., is an extension of the BC Pipeline System, which will supply gas to the facility under a 40-year transportation agreement.

GAS TRANSMISSION AND MIDSTREAM PROCEEDINGS

Texas Eastern Transmission

Texas Eastern Transmission, LP (Texas Eastern) filed two rate cases in the third quarter of 2021. These two rate proceedings have since been consolidated and settlement negotiations began during the first quarter of 2022. An uncontested settlement in principle was reached on July 7, 2022. Texas Eastern filed an uncontested Stipulation and Agreement on September 8, 2022 to resolve all issues from the rate proceedings. The Federal Energy Regulatory Commission (FERC) approved the Stipulation and Agreement on November 30, 2022, and the Stipulation and Agreement became effective on January 1, 2023.

Maritimes & Northeast Pipeline

The toll settlement agreement for the Canadian portion of our Maritimes & Northeast (M&N Canada) Pipeline system expired in December 2021. In December 2021, the Canada Energy Regulator (CER) approved interim tolls for M&N Canada effective January 1, 2022, which were based on the negotiated 2022 tolls in the 2022-2023 settlement agreement and unanimously supported by shippers. The 2022-2023 M&N Canada settlement agreement was approved by the CER in February 2022.

British Columbia Pipeline

The toll settlement agreement for our BC Pipeline system expired in December 2021. In December 2021, the CER approved interim tolls for BC Pipeline effective January 1, 2022. In the fourth quarter of 2022, a five-year 2022-2026 BC Pipeline settlement agreement was approved by shippers and subsequently approved as filed by the CER.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

2022 Rate Application

Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. In June 2021, Enbridge Gas filed Phase 1 of the application with the Ontario Energy Board (OEB) for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism and represents the fourth year of a five-year term. In October 2021, the OEB approved a Phase 1 Settlement Proposal and Interim Rate Order effective January 1, 2022. In April 2022, the OEB issued its decision on Phase 2 of the 2022 Application filed in October 2021, addressing incremental capital module (ICM) funding requirements, under which $127 million of the requested capital funding was approved and incorporated into final rates, effective July 1, 2022.

2023 Rate Application
In June 2022, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2023 (the 2023 Application). The 2023 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap IR rate setting mechanism and represents the final year of a five-year term. In November 2022, the OEB approved the Phase 1 Settlement Proposal and Final Rate Order effective January 1, 2023. In addition, Enbridge Gas did not anticipate 2023 capital investments to require incremental funding during the final year of its current Price Cap IR term, and, as such, Enbridge Gas did not make a Phase 2 ICM request as part of the 2023 Application.

2024 Rebasing and Incentive Rate-Setting Mechanism Application
In October 2022, Enbridge Gas filed its application with the OEB to establish a 2024 through 2028 rate setting framework. The application and framework seek approval to establish 2024 base rates on a cost-of-service basis and to establish a price cap IR rate setting mechanism to be used for the remainder of the IR term (2025-2028). The OEB has determined it will hear the application in two phases, with Phase 1 addressing items that affect rates effective January 1, 2024, and Phase 2 addressing items that will affect rates subsequent to January 1, 2024. An OEB decision is expected on Phase 1 of the application in the second half of 2023.

Purchase Gas Variance
The Purchase Gas Variance Account (PGVA) captures the difference between actual and forecasted natural gas prices reflected in rates. Account balances are typically recovered or refunded over a prospective 12-month period through Quarterly Rate Adjustment Mechanism (QRAM) applications.

In March and June 2022, the OEB approved Enbridge Gas' April 1, 2022 and July 1, 2022 QRAM applications, respectively. Due to the significant increase in natural gas prices, the approvals have also included rate mitigation plans intended to ease bill impacts to ratepayers. Specifically, the approved rate mitigation plans extended the PGVA recovery period from 12 months to 24 months in both applications. As an additional mitigation measure, as part of the April 1, 2022 QRAM, a portion of the PGVA balance was deferred for recovery, which was subsequently approved for recovery as part of the July 1, 2022 QRAM. In September and December 2022, the October 1, 2022 and January 1, 2023 QRAM applications were filed and approved by the OEB with no adjustments to the prior period rate mitigation plans and did not include any additional rate mitigation measures.

As at December 31, 2022, Enbridge Gas' PGVA receivable balance was $434 million.

FINANCING UPDATE
We completed long-term debt issuances totaling US$3.2 billion and $3.4 billion during the year ended December 31, 2022, including $900 million of 10-year sustainability-linked medium-term notes in November 2022. We increased our credit facilities during our annual renewal process by approximately $640 million and also entered into new term loans with maturities ranging from 2023 to 2027 totaling approximately $3.2 billion.

Our 2022 financing activities have provided significant liquidity that we expect will enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months should market access be restricted or pricing be unattractive. Refer to *Liquidity and Capital Resources*.

As at December 31, 2022, after adjusting for the impact of floating-to-fixed interest rate swap hedges, approximately 6% of our total debt is exposed to floating rates. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments* for more information on our interest rate hedging program.

NORMAL COURSE ISSUER BID

On January 4, 2023, we announced that the Toronto Stock Exchange (TSX) had approved our new normal course issuer bid (NCIB) to purchase for cancellation up to 27,938,163 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day. The NCIB follows on the termination of our prior NCIB, which expired on January 4, 2023.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and alternative trading systems commencing on January 6, 2023 and continuing until January 5, 2024, when the NCIB expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decided not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may purchase for cancellation under the NCIB represents approximately 1.38% of the 2,024,890,423 common shares issued and outstanding as at December 23, 2022.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) to provide information about us and our subsidiaries and affiliates, including management's assessment of our and our subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquified natural gas (LNG) and renewable energy; energy transition and lower-carbon energy, and our approach thereto; environmental, social and governance (ESG) goals, practices and performance; industry and market conditions; anticipated utilization of our assets; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; share repurchases under our normal course issuer bid; expected equity funding requirements for our commercially secured growth program; expected future growth, development and expansion opportunities; expected optimization and efficiency opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions; expected future actions of regulators and courts, and the timing and impact thereof; toll and rate cases discussions and proceedings and anticipated timeline and impact therefrom, including Mainline Contracting and those relating to the Gas Transmission and Midstream and Gas Distribution and Storage businesses; operational, industry, regulatory, climate change and other risks associated with our businesses; and our assessment of the potential impact of the various risk factors identified herein.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of, demand for, export of and prices of crude oil, natural gas, NGL, LNG and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; the COVID-19 pandemic and the duration and impact thereof; availability and price of labor and construction materials; the stability of our supply chain; operational reliability; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits of transactions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected earnings before interest, income taxes, and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL, LNG and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates and the COVID-19 pandemic impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the stability of our supply chain; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance; legislative and regulatory parameters; litigation; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; operational dependence on third parties; dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; inflation; interest rates; commodity prices; access to and cost of capital; political decisions; global geopolitical conditions; the supply of, demand for and prices of commodities and other alternative energy; and the COVID-19 pandemic, including but not limited to, those risks and uncertainties discussed in this MD&A and in our other filings with Canadian and US securities regulators. The impact of any one assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statement made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

Non-GAAP and Other Financial Measures

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes and depreciation and amortization. Management uses EBITDA to assess performance of Enbridge and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.

The non-GAAP and other financial measures are not measures that have a standardized meaning prescribed by the accounting principles generally accepted in the United States of America (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedar.com or www.sec.gov.

RESULTS OF OPERATIONS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**8,364**	7,897	7,683
Gas Transmission and Midstream	**3,126**	3,671	1,087
Gas Distribution and Storage	**1,827**	2,117	1,748
Renewable Power Generation	**262**	508	523
Energy Services	**(417)**	(313)	(236)
Eliminations and Other	**(1,124)**	356	(113)
Earnings before interest, income taxes and depreciation and amortization[1]	**12,038**	14,236	10,692
Depreciation and amortization	**(4,317)**	(3,852)	(3,712)
Interest expense	**(3,179)**	(2,655)	(2,790)
Income tax expense	**(1,604)**	(1,415)	(774)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**65**	(125)	(53)
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders	**1.28**	2.87	1.48

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2022 compared with year ended December 31, 2021

Earnings attributable to common shareholders decreased by $3,368 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- a goodwill impairment of $2.5 billion relating to our Gas Transmission reporting unit;
- non-cash, net unrealized derivative fair value losses of $1,265 million ($964 million after-tax) in 2022, compared with unrealized gains of $197 million ($150 million after-tax) in 2021, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- an asset impairment loss of $227 million ($173 million after-tax) to our Magic Valley Wind Farm (Magic Valley);
- an asset impairment loss of $183 million ($137 million after-tax) on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project;

- an impairment of $44 million ($34 million after-tax) for lease assets due to office relocation plans;
- an asset impairment loss of $40 million ($30 million after-tax) relating to MacKay River line within our Alberta Regional Oil Sands System;
- the absence in 2022 of a gain of $303 million ($298 million after-tax) from the sale of our investment in Noverco Inc. (Noverco); and
- the absence in 2022 of a $57 million ($43 million after-tax) property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

The factors above were partially offset by:
- a gain of $1,076 million ($732 million after-tax) on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- a gain of $118 million ($89 million after-tax) on Texas Eastern recorded to reflect a settlement with a transportation customer undergoing bankruptcy;
- a deferred tax benefit of $95 million recognized as a result of the reduced Pennsylvania state corporate income tax;
- a non-cash, net negative equity earnings adjustment of $10 million ($7 million after-tax) in 2022, compared to a net negative adjustment of $44 million ($33 million after-tax) in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investee, DCP;
- transition and transformation costs of $66 million ($50 million after-tax) in 2022, compared to $147 million ($112 million after-tax) in 2021; and
- the absence in 2022 of an impairment loss of $111 million ($83 million after-tax) to our investment in the PennEast Pipeline Company, LLC (PennEast) pipeline project.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of our comprehensive economic hedging program to mitigate foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $141 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:
- higher throughput within our Liquids Pipelines segment driven by higher demand and incremental Line 3 Replacement (L3R) capacity that came into service October 2021;
- increased earnings within our Liquids Pipelines segment from the implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021, as well as from new US export assets acquired in October 2021;
- increased earnings from our Gas Transmission and Midstream segment primarily as a result of higher commodity prices benefiting our investments in DCP and Aux Sable, as well as higher contributions from projects placed into service in November 2021; and
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement; partially offset by
- the recognition of a provision against the interim Mainline International Joint Tariff (IJT) for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the Competitive Toll Settlement (CTS);
- higher interest expense primarily due to higher interest rates and higher average principal, as well as reduced capitalized interest associated with the US portion of the L3R Project placed into service in the fourth quarter of 2021;
- higher depreciation and amortization expense as a result of several projects placed into service in the fourth quarter of 2021, as well as for new US export assets acquired in October 2021; and
- higher income tax expense due to higher earnings, higher US minimum taxes, and the effect of rate-regulated accounting for income taxes.

REVENUES
We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of $18.5 billion, $16.2 billion and $16.2 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $5.7 billion, $4.0 billion and $3.7 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of $29.2 billion, $26.9 billion and $19.3 billion for the years ended December 31, 2022, 2021 and 2020, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGL) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**8,364**	7,897	7,683

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $710 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- non-cash, net unrealized losses of $183 million in 2022, compared with unrealized gains of $120 million in 2021, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- total asset impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- an asset impairment loss of $40 million relating to MacKay River line within our Alberta Regional Oil Sands System; and
- the absence in 2022 of a $57 million property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

After taking into consideration the factors above, the remaining $1.2 billion increase is primarily explained by the following significant business factors:

- higher Mainline System ex-Gretna average throughput of 3.0 million barrels per day (mmbpd) in 2022 as compared to 2.8 mmbpd in 2021 driven by higher demand and incremental L3R capacity that came into service October 2021;
- implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021;
- higher contributions from the Gulf Coast and Mid-Continent System due primarily to the acquisition of the Enbridge Ingleside Energy Center and related assets in the fourth quarter of 2021 in addition to the increased effective economic interest in the Gray Oak pipeline during the third quarter of 2022 and higher volumes from Flanagan South Pipeline;
- higher contributions from the Bakken System due to higher volumes; and
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021; partially offset by
- the recognition of a provision against the interim Mainline IJT for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the CTS;
- lower contributions from the Seaway Crude Pipeline System, as well as from the Cushing and Hardisty storage assets as a result of lower demand; and
- higher power costs as a result of increased volumes and power prices.

GAS TRANSMISSION AND MIDSTREAM

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**3,126**	3,671	1,087

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.1 billion due to certain infrequent or other non-operating factors primarily explained by the following:

- a goodwill impairment of $2.5 billion; partially offset by
- a gain of $1,076 million on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- the absence of the $111 million impairment loss in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development;
- a gain of $118 million on Texas Eastern recorded for a customer bankruptcy settlement; and
- a non-cash, net negative equity earnings adjustment of $10 million in 2022, compared to a net negative adjustment of $44 million in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investees, DCP and Aux Sable.

After taking into consideration the factors above, we saw a $567 million increase, primarily explained by the following significant business factors:

- higher commodity prices benefiting our DCP and Aux Sable joint ventures;
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021;
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement;
- contributions from the T-South and Spruce Ridge expansion projects, the Cameron and Middlesex Extension projects, and the Appalachia to Market project after service commenced in the fourth quarter of 2021;
- higher AECO-Chicago basis differential and lower costs benefiting earnings from our investment in Alliance; and
- recognition of revenues attributable to the BC Pipeline rate settlement; partially offset by
- higher operating costs; and
- a reduction in earnings from our investment in DCP as a result of our decreased effective economic interest due to the joint venture merger transaction with P66 that closed during the third quarter of 2022.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**1,827**	2,117	1,748

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $293 million due to certain infrequent or other non-operating factors primarily explained by the absence of a gain of $303 million resulting from the sale of our investment in Noverco in 2021.

After taking into consideration the factors above, the remaining $3 million increase is primarily explained by the following significant business factors:

- higher distribution charges at Enbridge Gas resulting from increases in rates and customer base, as well as higher demand in the contract market;
- when compared with the normal weather forecast embedded in rates, colder than normal weather in 2022 positively impacted Enbridge Gas 2022 EBITDA by approximately $17 million while warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately $55 million; and
- lower pension related costs; partially offset by
- the absence of earnings from Noverco due to the sale of our minority investment in December 2021; and
- higher operating costs at Enbridge Gas largely driven by higher employee costs and higher maintenance and integrity spend.

RENEWABLE POWER GENERATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**262**	508	523

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $272 million due to certain infrequent or non-operating factors, primarily explained by an impairment loss of $227 million to Magic Valley.

After taking into consideration the negative factor above, the remaining $26 million increase is primarily explained by the following significant business factors:

- higher energy pricing at European offshore wind facilities;
- stronger wind resources at Canadian and US onshore wind facilities; and
- the absence in 2022 of the adverse effects from the major winter storm in Texas during February 2021; partially offset by
- the absence in 2022 of a promote fee received in the first quarter of 2021 associated with the closing of the sale of 49% of our interest in three European offshore wind projects to Canada Pension Plan Investment Board.

ENERGY SERVICES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(417)**	(313)	(236)

1 Non-GAAP financial measure.

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $100 million due to certain non-operating factors, primarily explained by non-cash, unrealized losses of $27 million in 2022, compared with unrealized gains of $53 million in 2021, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as to manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining $4 million decrease is primarily explained by the following significant business factors:

- more pronounced market structure backwardation than in 2021 and significant compression of location differentials in certain markets; partially offset by
- the absence of adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(1,124)**	356	(113)

1 Non-GAAP financial measure.

Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. Eliminations and Other also includes the impact of new business development activities and corporate investments.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.2 billion due to certain infrequent or non-operating factors, primarily explained by:

- non-cash, net unrealized losses of $1,090 million in 2022, compared with unrealized gains of $55 million in 2021, reflecting the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project; and
- an impairment of $44 million for lease assets due to office relocation plans in Houston.

After taking into consideration the non-operating factors above, we saw a $239 million decrease in EBITDA that is primarily explained by:

- the lower realized foreign exchange gains on hedge settlements in 2022; and
- higher Operating and administrative expense largely driven by an increase in employee costs.

GROWTH PROJECTS - COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our significant commercially secured projects, organized by business segment:

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
GAS TRANSMISSION AND MIDSTREAM						
1.	Vito Gas & Oil	100 %	US$0.3 billion	US$0.2 billion	Complete	In-service
2.	Texas Eastern Venice Extension Project	100 %	US$0.4 billion	US$0.1 billion	Pre-construction	2023 - 2024
3.	Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2025
4.	T-North Expansion	100 %	$1.2 billion	No significant expenditures to date	Pre-construction	2026
5.	Woodfibre LNG Project[3]	30 %	US$1.5 billion	No significant expenditures to date	Pre-construction	2027
6.	T-South Expansion	100 %	$3.6 billion	No significant expenditures to date	Pre-construction	2028
RENEWABLE POWER GENERATION						
7.	Saint-Nazaire France Offshore Wind Project[4]	25.5 %	$0.9 billion (€0.6 billion)	$0.9 billion (€0.6 billion)	Complete	In-service
8.	Fécamp Offshore Wind Project[5]	17.9 %	$0.7 billion (€0.5 billion)	$0.4 billion (€0.3 billion)	Under construction	2023
9.	Calvados Offshore Wind Project[4]	21.7 %	$0.9 billion (€0.6 billion)	$0.3 billion (€0.2 billion)	Under construction	2025

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date and status of the project are determined as at December 31, 2022.
3 Our equity contribution is US$0.9 billion, with the remainder financed through non-recourse project level debt.
4 Our equity contribution is $0.2 billion for each project, with the remainder of each project financed through non-recourse project level debt.
5 Our equity contribution is $0.1 billion, with the remainder financed through non-recourse project level debt.

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors.*

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth project was placed into service in 2022:

- **Vito Gas & Oil** – Two pipelines connecting Vito Floating Production System from Mississippi Canyon to the Shell Mars System platform in West Delta 143 and Olympic Gas. Enbridge designed, fabricated, installed, and now operates, the Vito Gas & Oil export pipeline system consisting of pipeline and steel catenary riser.

The following commercially secured growth projects are currently in various stages of construction:

- **Texas Eastern Venice Extension Project** – A reversal and expansion of Texas Eastern’s Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern’s Larose compressor station. The project is expected to deliver 1.5 billion cubic feet per day (bcf/d) of natural gas to Venture Global Plaquemines LNG, LLC’s LNG export facility located in Plaquemines Parish, Louisiana and is underpinned by long-term take or pay contracts.

- **Texas Eastern Modernization –** This program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program will be completed in stages over a period of years beginning in 2024.

- **T-North Expansion** – An expansion of Westcoast Energy Inc.'s (Westcoast) BC Pipeline in northern BC that includes pipeline looping, additional compressor units and other ancillary station modifications to support 535 million cubic feet per day (MMcf/d) of additional capacity. The project will be underpinned by a cost-of-service commercial model with a target in-service date of 2026.

- **Woodfibre LNG Project** – Construction of liquefaction and floating storage facilities in Squamish, BC, as well as an expansion of the BC Pipeline System. The project is expected to be placed into service in 2027.

- **T-South Expansion** – An expansion of Westcoast's BC Pipeline's T-South section that includes pipeline looping, additional compressor units and other ancillary station modifications to support 300 MMcf/d of additional capacity. The project is expected to be placed in service in 2028 and will be underpinned by a cost-of-service commercial model.

RENEWABLE POWER GENERATION
The following commercially secured growth projects were placed into service in 2022:

- **Saint-Nazaire Offshore Wind Project –** A wind project located off the west coast of France that is expected to generate approximately 480 megawatts (MW). Project revenues are backed by a 20-year fixed price power purchase agreement (PPA) with added power production protection.

The following commercially secured growth projects are expected to be placed into service from 2023 to 2025:

- **Fécamp Offshore Wind Project –** An offshore wind project that will be comprised of 71 wind turbines located off the northwest coast of France and is expected to generate approximately 500 MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Calvados Offshore Wind Project –** An offshore wind project located off the northwest coast of France that is expected to generate approximately 448 MW. Project revenues are underpinned by a 20-year fixed price PPA.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following project has been announced by us, but has not yet met our criteria to be classified as commercially secured:

GAS TRANSMISSION AND MIDSTREAM

- **Valley Crossing Expansion Project** – On January 10, 2022, we executed a precedent agreement with Texas LNG Brownsville LLC (Texas LNG) under which, via an expansion of our Valley Crossing Pipeline, we will provide 0.72 bcf/d firm transportation capacity to Texas LNG's proposed LNG liquefaction and export facility in the Port of Brownsville, Texas for a term of at least 20 years. Expansion of the pipeline will be subject to Texas LNG's export facility reaching a final investment decision.

We also have a portfolio of additional projects under development that have not yet progressed to the point of securement.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control including, but not limited to, financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary data - Note 18 - Debt* and *Note 27 - Leases* for amounts outstanding at December 31, 2022, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $7.9 billion which are expected to be paid over the next five years. Long-term contracts primarily consists of the following purchase obligations: firm capacity payments for natural gas and crude oil transportation and storage contracts, natural gas purchase commitments, service and product purchase obligations and power commitments.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of common equity.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan, we completed the following long-term debt issuances totaling US$3.2 billion and $3.4 billion in 2022:

Entity	Issuance date	Type of issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	January 2022	Fixed-to-fixed subordinated notes	$750
Enbridge Inc.	February 2022	Floating rate senior notes	US$600
Enbridge Inc.	February 2022	Senior notes	US$900
Enbridge Inc.	September 2022	Fixed-to-fixed subordinated notes	US$1,100
Enbridge Inc.	November 2022	Medium-term notes	$1,100
Enbridge Inc.	November 2022	Sustainability-linked medium-term notes	$900
Enbridge Gas Inc.	August 2022	Medium-term notes	$650
Texas Eastern Transmission LP	December 2022	Senior notes	US$600

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities, inclusive of term loans, at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 10, 2022, we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized.

As at December 31, 2022, our net available liquidity totaled $10.0 billion (2021 - $6.5 billion), consisting of available credit facilities of $9.1 billion (2021 - $6.2 billion) and unrestricted Cash and cash equivalents of $861 million (2021 - $286 million) as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2022, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. In 2022, our credit ratings with DBRS Morningstar, Fitch Ratings, Moody's Investor Services, Inc. and Standard & Poor's were all affirmed. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

There are no material restrictions on our cash. Total Restricted cash of $46 million, as reported in the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2022 and 2021, we had a negative working capital position of $2.1 billion and $3.1 billion, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities	**11,230**	9,256	9,781
Investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)

Significant sources and uses of cash for the years ended December 31, 2022 and 2021 are summarized below:

Operating Activities
Typically, the primary factors impacting cash flow from operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 29. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed under *Results of Operations.*

Investing Activities
Cash used in investing activities primarily relates to capital expenditures to execute our capital program, which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2022, 2021 and 2020 is set out below:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Liquids Pipelines	**1,418**	4,051	2,032
Gas Transmission and Midstream	**1,647**	2,353	2,066
Gas Distribution and Storage	**1,499**	1,343	1,134
Renewable Power Generation	**50**	16	81
Energy Services	**—**	1	2
Eliminations and Other	**33**	54	90
Total capital expenditures	**4,647**	7,818	5,405

2022
The decrease in cash used in investing activities primarily resulted from the following factors:

- lower capital expenditures due to the US L3R Program that was placed into service in the fourth quarter of 2021;
- lower cash outflows related to acquisitions in 2022 when compared to 2021; and
- proceeds received from the completion of a joint venture merger transaction for DCP Midstream LLC in August 2022.

The factors above were partially offset by:

- the absence in 2022 of proceeds received from dispositions in 2021 related to sale of our interest in Noverco in December 2021; and
- increased investments held by our wholly-owned captive insurance subsidiaries.

2021
The increase in cash used in investing activities primarily resulted from our acquisition of Moda Midstream Operating, LLC and higher capital expenditures related to the completion of the US L3R Program in 2021, partially offset by higher proceeds received from dispositions in 2021 compared to 2020 due to the sale of our interest in Noverco.

Financing Activities
Cash used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances, share redemptions and common share repurchases under our NCIB. Cash flow from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2022
The increase in cash used in financing activities primarily resulted from the following factors:

- net commercial paper and credit facility repayments in 2022 when compared to draws in 2021;
- higher long-term debt repayments along with lower long-term debt issuances in 2022 when compared to 2021;
- the redemption of Preference Shares, Series 17 and Series J in the first and second quarters of 2022, respectively;
- the repurchase and cancellation of 2,737,965 common shares under our NCIB for approximately $151 million in 2022; and
- increased common share dividend payments primarily due to the increase in our common share dividend rate.

The factors above were partially offset by:

- proceeds received from the sale of a non-operating interest in seven pipelines from our Regional Oil Sands System in October 2022;
- the absence in 2022 of the redemption of Westcoast's preferred shares in the first quarter of 2021; and
- higher short-term borrowings in 2022 when compared to 2021.

2021
The increase in cash provided by financing activities primarily resulted from increased issuances of long-term debt, commercial paper and credit facility draws and short-term borrowings, along with lower repayments of long-term debt in 2021 when compared to 2020.

The factors above were partially offset by the redemption of Westcoast's preferred shares in 2021 and increased common share dividend payments primarily due to the increase in our common share dividend rate.

OFF-BALANCE SHEET ARRANGEMENTS

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties and can include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Please see Part II. *Item 8. Financial Statements and Supplementary Data - Note 32. Guarantees* for further discussion of guarantee arrangements.

We do not have material off-balance sheet financing entities or structures, except for guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, please refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Commitments and Contingencies* and *Note 12. Variable Interest Entities.*

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

PREFERENCE SHARE ISSUANCES

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)					
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20%	$1.30052	$25	June 1, 2027	Series C
Preference Shares, Series D	4.46%	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69%	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38%	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series L[6]	5.86%	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	5.09%	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38%	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07%	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95%	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74%	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38%	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45%	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10%	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94%	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04%	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98%	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 19	4.90%	$1.22500	$25	March 1, 2023	Series 20

1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.

2 Preference Shares, Series A may be redeemed any time at our option. For all other series of preference shares, we may at our option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

4 With the exception of Preference Shares, Series A, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/number of days in year) x Three-Month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).

5 The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.

6 The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.

PREFERENCE SHARE REDEMPTIONS

On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17. On June 1, 2022, we also redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J. Dividends are cumulative, payable quarterly and are included in Preference share dividends in the Consolidated Statements of Earnings.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In November 2022, we announced a 3.2% increase in our quarterly dividend to $0.88750 per common share, or $3.55 annualized, effective with the dividend payable on March 1, 2023, thereby declaring a dividend increase for 28 straight years.

For the years ended December 31, 2022 and 2021, total dividends paid were $7.0 billion and $6.8 billion, respectively, all of which were paid in cash and reflected in financing activities.

On November 29, 2022, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2023 to shareholders of record on February 15, 2023.

	Dividend per share
Common Shares[1]	$0.88750
Preference Shares, Series A	$0.34375
Preference Shares, Series B[2]	$0.32513
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series L[3]	US$0.36612
Preference Shares, Series N	$0.31788
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 19	$0.30625

1 The quarterly dividend per common share was increased 3.2% to $0.8875 from $0.860, effective March 1, 2023.

2 The quarterly dividend per share paid on Preference Shares Series B was increased to $0.32513 from $0.21340 on June 1, 2022, due to reset of the annual dividend on June 1, 2022 and every five years thereafter. Following the date of conversion of Preference Shares Series C, on June 1, 2022 all outstanding Preference Shares Series C were converted to Preference Shares Series B.

3 The quarterly dividend per share paid on Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022, and every five years thereafter.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and Enbridge Energy Partners, L.P. (EEP) (the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes (the Guaranteed Enbridge Notes), and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
4.750% Senior Notes due 2024	5.875% Notes due 2025
3.500% Senior Notes due 2025	5.950% Notes due 2033
3.375% Senior Notes due 2026	6.300% Notes due 2034
5.950% Senior Notes due 2043	7.500% Notes due 2038
4.500% Senior Notes due 2045	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at December 31, 2022, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Floating Rate Senior Notes due 2023	3.940% Senior Notes due 2023
Floating Rate Senior Notes due 2024	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.950% Senior Notes due 2024
0.550% Senior Notes due 2023	2.440% Senior Notes due 2025
3.500% Senior Notes due 2024	3.200% Senior Notes due 2027
2.150% Senior Notes due 2024	5.700% Senior Notes due 2027
2.500% Senior Notes due 2025	6.100% Senior Notes due 2028
2.500% Senior Notes due 2025	2.990% Senior Notes due 2029
4.250% Senior Notes due 2026	7.220% Senior Notes due 2030
1.600% Senior Notes due 2026	7.200% Senior Notes due 2032
3.700% Senior Notes due 2027	6.100% Sustainability-Linked Senior Notes due 2032
3.125% Senior Notes due 2029	3.100% Sustainability-Linked Senior Notes due 2033
2.500% Sustainability-Linked Senior Notes due 2033	5.570% Senior Notes due 2035
4.500% Senior Notes due 2044	5.750% Senior Notes due 2039
5.500% Senior Notes due 2046	5.120% Senior Notes due 2040
4.000% Senior Notes due 2049	4.240% Senior Notes due 2042
3.400% Senior Notes due 2051	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	6.510% Senior Notes due 2052
	4.560% Senior Notes due 2064

1 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$11.0 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $10.2 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act) for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and the Summarized Combined Statements of Financial Position combines the balances of EEP, SEP and Enbridge.

Summarized Combined Statement of Earnings

Year ended December 31,	**2022**
(millions of Canadian dollars)	
Operating loss	**(179)**
Earnings	**1,921**
Earnings attributable to common shareholders	**1,507**

Summarized Combined Statements of Financial Position

December 31,	**2022**	2021
(millions of Canadian dollars)		
Cash and cash equivalents	**425**	12
Accounts receivable from affiliates	**2,486**	3,442
Short-term loans receivable from affiliates	**5,232**	4,947
Other current assets	**969**	593
Long-term loans receivable from affiliates	**43,873**	51,983
Other long-term assets	**4,111**	3,732
Accounts payable to affiliates	**1,375**	1,982
Short-term loans payable to affiliates	**1,745**	2,891
Other current liabilities	**8,752**	8,110
Long-term loans payable to affiliates	**37,626**	41,370
Other long-term liabilities	**47,447**	41,353

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor’s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge's direct or indirect limited partnership of other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;
- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities**.**

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Line 5 Easement (Bad River Band)

On July 23, 2019, the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) filed a complaint in the United States District Court for the Western District of Wisconsin (the Court) over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. The Band alleges that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and that the pipeline is in trespass on certain tracts of land in which the Band possesses ownership interests. The complaint seeks an Order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. Subsequently amended versions of the complaint also seek recovery of profits-based damages based on an unjust enrichment theory. Enbridge has responded to each claim in the initial and amended complaints with an answer, defenses and counterclaims.

On August 29, 2022, the Government of Canada released a statement formally invoking the dispute settlement provisions of the 1977 Transit Pipelines Treaty in respect of this litigation; reiterating its concerns about the uninterrupted transmission of hydrocarbons through Line 5. On September 7, 2022, the Court issued a decision on cross-motions for summary judgment. The Court determined that the Band's nuisance claim raised factual issues that could not be resolved on summary judgment. The Court further determined that Enbridge is in trespass on 12 parcels on the Reservation and that the Band is entitled to some measure of profits-based damages and to an injunction, with the level of damages and scope of the injunction to be determined at trial, which occurred between October 24 and November 1, 2022. While the Court reserved judgment at the conclusion of the trial, the summary judgment decision and subsequent pre-trial decisions provide that the Court will assess trespass damages calculated using a pro-rata share of Enbridge's profits from the operation of the pipeline attributable to the 12 disputed parcels compared to the pipeline as a whole rather than the profits associated with the entire length of the pipeline, as the Band sought. The Court has also stated that any injunction will not result in the immediate closure of the pipeline but also will not allow the pipeline to operate indefinitely. On November 28, 2022, the Court issued an interim Order ruling that: (a) the parties are to meet and confer by December 16 on installation of EFRDs (Emergency Flow Restriction Devices) on the Reservation, an appropriate shutdown and purge protocol should conditions worsen at the meander, and any other reasonable remediation projects that could inhibit further erosion at the meander; (b) the parties are to submit a Joint Proposal by December 23 on appropriate shutoff and purge plan for the meander, or if they cannot agree, each party must submit their own best offer on a shutdown and purge protocol; and (c) denied Enbridge's request for declaratory and injunctive relief on its counterclaims asking for Court-Ordered relief relating to access and erosion mitigation at the meander. The parties met and conferred by December 16 and a Joint Status Report, along with individual best offers on shutdown and purge protocol, were filed on December 23. We continue to wait on the Court's rulings on the issues of financial compensation and Line 5's operations.

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement
In 2019, the Michigan Attorney General (AG) filed a complaint in the Michigan Ingham County Circuit Court (the Circuit Court) that requests the Circuit Court to declare the easement granted in 1953 that we have for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits. On December 15, 2021, we removed the case to the US District Court in the Western District of Michigan (US District Court), where it was assigned to Judge Janet T. Neff. The removal of the AG's case to federal court follows a November 16, 2021 ruling which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor of Michigan to force Line 5's shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the AG made a request to file a remand motion and on December 28, 2021, we responded to her request to file that motion. On January 5, 2022, the court issued an Order allowing the AG to file a motion to remand the 2019 case. The AG's motion and brief were filed on January 14, 2022, and our response was filed on February 11, 2022. The motion was fully briefed in March 2022. On August 18, 2022, Judge Neff denied the AG's motion to remand which now remains in the US District Court. On August 30, 2022, the AG filed a motion to certify the US District Court's August 18 Order to pursue an appeal on the jurisdictional issue, which Enbridge opposed. We anticipate a decision on the jurisdictional issue in 2023.

Dakota Access Pipeline
We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of the Dakota Access Pipeline (DAPL). The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) contesting the lawfulness of the Army Corps easement for DAPL, including the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL. In August 2018, the Army Corps completed on remand the further environmental review ordered by the District Court and reaffirmed the issuance of the easement for DAPL. All four plaintiff Tribes subsequently amended their complaints to include claims challenging the adequacy of the Army Corps' August 2018 remand decision.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found the Army Corps' environmental review on remand was deficient and ordered the Army Corps to prepare an Environmental Impact Statement (EIS) to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the Army Corps appealed the decision and filed a motion for a stay pending appeal with the US Court of Appeals for the District of Columbia Circuit. On August 5, 2020, the US Court of Appeals stayed the District Court's July 6 order to shut down and empty the pipeline, but did not stay the District Court's March 25 order requiring the Army Corps to prepare an EIS or the District Court's July 6 order vacating the DAPL easement.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. On February 22, 2022, the US Supreme Court denied the request of Dakota Access, LLC to review the decision that an EIS is required. The US Court of Appeals also determined that, absent considering the closure of DAPL in the context of an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before the US Court of Appeals, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement.

On May 21, 2021, the District Court dismissed the plaintiff Tribes' request for an injunction enjoining DAPL from operating until the Army Corps has completed its EIS. The right of the plaintiff Tribes to appeal the denial of the injunction request expired on July 20, 2021. The Army Corps earlier indicated that it did not intend, at that time, to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement and that it anticipates completion of the EIS process.

On July 22, 2021, the Army Corps filed a notice with the District Court advising that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a notice asserting violations of federal safety regulations resulting from the operation of DAPL. The Army Corps stated that it would consider PHMSA's notice as part of its ongoing consideration of whether and how the Army Corps will enforce its rights on property crossed by the pipeline and in the context of the ongoing EIS. The Army Corps also granted the request from the Tribes to extend the draft EIS completion date to September 2022. The Army Corps now expects to complete the draft EIS in the spring of 2023.

OTHER LITIGATION

We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

BUSINESS COMBINATIONS

We apply the provisions of Accounting Standards Codification (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

GOODWILL IMPAIRMENT

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill starting in the third quarter of 2022.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, the assessment of macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends and changes to industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiplier for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples for reporting units. The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

On April 1, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that has led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss in Gas Transmission. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution, or Renewable Power Generation reporting units.

ASSET IMPAIRMENT

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We regularly monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

ASSETS HELD FOR SALE

We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

REGULATORY ACCOUNTING

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the CER, the FERC, the Alberta Energy Regulator, La Régie de l'energie du Québec and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- interest costs on the debt component of the capital structure; and
- contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2022 and 2021, our regulatory assets totaled $6.5 billion and $5.9 billion, respectively, and regulatory liabilities totaled $3.8 billion and $3.4 billion, respectively.

DEPRECIATION

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2022 and 2021, of $104.5 billion and $100.1 billion, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2022 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit (OPEB) obligation assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	243	27	49	3
Decrease in expected return on assets	—	23	—	6
Decrease in rate of salary increase	(47)	(11)	(5)	(1)
OPEB				
Decrease in discount rate	13	1	5	—
Decrease in expected return on assets	N/A	N/A	—	1

CONTINGENT LIABILITIES

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS
Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% to 9.0%). ARO is added to the carrying value of the associated asset and depreciated over the asset’s useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

CHANGES IN ACCOUNTING POLICIES

Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies*.