



**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549**

**FORM 10-Q**

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE  
SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended March 31, 2019**

**OR**

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE  
SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from \_\_\_\_\_ to \_\_\_\_\_  
Commission file number 1-10934**



**ENBRIDGE INC.**

(Exact Name of Registrant as Specified in Its Charter)

**Canada**

(State or Other Jurisdiction of  
Incorporation or Organization)

**98-0377957**

(I.R.S. Employer  
Identification No.)

**200, 425 - 1st Street S.W.**

**Calgary, Alberta, Canada T2P 3L8**

(Address of Principal Executive Offices) (Zip Code)

**(403) 231-3900**

(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

**Title of each class**

Common Shares

**Trading Symbol(s)**

ENB

**Name of each exchange on which registered**

New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes  No

The registrant had 2,023,709,816 common shares outstanding as at May 3, 2019.

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## GLOSSARY

AOCI	Accumulated other comprehensive income/(loss)
Army Corps	United States Army Corps of Engineers
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
EBITDA	Earnings before interest, income taxes and depreciation and amortization
Eddystone Rail	Eddystone Rail Company, LLC
EEP	Enbridge Energy Partners, L.P.
Enbridge	Enbridge Inc.
kbpd	thousands of barrels per day
Market Risk	Movements in foreign exchange rates, interest rates, commodity prices and the Company's share price.
NGL	Natural gas liquids
OCI	Other comprehensive income/(loss)
SEP	Spectra Energy Partners, LP
the Court	United States District Court for the Eastern District of Pennsylvania
U.S. L3R Program	United States Line 3 Replacement Program
VIE	Variable Interest Entity

## CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. 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.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to "dollars", "\$" or "C\$" are to Canadian dollars and all references to "US\$" are to United States dollars. All amounts are provided on a before tax basis, unless otherwise stated.

## FORWARD-LOOKING INFORMATION

*Forward-looking information, or forward-looking statements, have been included in this quarterly report on Form 10-Q 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: expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution, Renewable Power Generation and Transmission, and Energy Services businesses; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and expected timing thereof; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the stock-for-stock merger transaction completed on February 27, 2017 between Enbridge and Spectra Energy Corp (the Merger Transaction) including our combined scale, financial flexibility, growth program, future business prospects and performance; United States Line 3 Replacement Program (U.S. L3R Program); expected impact of the Federal Energy Regulatory Commission (FERC) policy on treatment of income taxes; the transactions undertaken to simplify our corporate structure; our dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of our hedging program; and expectations resulting from the successful execution of our 2018-2020 Strategic Plan.*

*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 and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of dispositions; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of the dividend policy on our future cash flows; credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL 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 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. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with*

*respect to the impact of the Merger Transaction on us, expected EBITDA, expected earnings/(loss), expected earnings/(loss) per share, or estimated future dividends. 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 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 and regulatory approvals on construction and in-service schedules and cost recovery regimes.*

*Our forward-looking statements are subject to risks and uncertainties pertaining to the realization of anticipated benefits and synergies of the Merger Transaction, operating performance, regulatory parameters, changes in regulations applicable to our business, dispositions, the transactions undertaken to simplify our corporate structure, our 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, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this quarterly report on Form 10-Q and in our other filings with Canadian and United States securities regulators. The impact of any one 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 Inc. assumes no obligation to publicly update or revise any forward-looking statements made in this quarterly report on Form 10-Q 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.*

## PART I - FINANCIAL INFORMATION

### ITEM 1. FINANCIAL STATEMENTS

#### ENBRIDGE INC. CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2019	2018
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>		
Operating revenues		
Commodity sales	6,632	7,268
Gas distribution sales	1,876	1,926
Transportation and other services	4,348	3,532
Total operating revenues <i>(Note 3)</i>	12,856	12,726
Operating expenses		
Commodity costs	6,565	6,997
Gas distribution costs	1,207	1,324
Operating and administrative	1,625	1,641
Depreciation and amortization	840	824
Impairment of long-lived assets	—	1,062
Total operating expenses	10,237	11,848
Operating income	2,619	878
Income from equity investments	413	335
Other income/(expense)		
Net foreign currency gain/(loss)	214	(185)
Other	46	65
Interest expense	(685)	(656)
Earnings before income taxes	2,607	437
Income tax (expense)/recovery <i>(Note 12)</i>	(584)	73
Earnings	2,023	510
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(37)	24
Earnings attributable to controlling interests	1,986	534
Preference share dividends	(95)	(89)
Earnings attributable to common shareholders	1,891	445
Earnings per common share attributable to common shareholders <i>(Note 5)</i>	0.94	0.26
Diluted earnings per common share attributable to common shareholders <i>(Note 5)</i>	0.94	0.26

*See accompanying notes to the interim consolidated financial statements.*

# ENBRIDGE INC.

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2019	2018
<i>(unaudited; millions of Canadian dollars)</i>		
Earnings	2,023	510
Other comprehensive income/(loss), net of tax		
Change in unrealized gain/(loss) on cash flow hedges	(192)	66
Change in unrealized gain/(loss) on net investment hedges	94	(184)
Other comprehensive income from equity investees	12	14
Reclassification to earnings of (gain)/loss on cash flow hedges	11	37
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	38	(39)
Foreign currency translation adjustments	(1,291)	1,579
Other comprehensive income/(loss), net of tax	(1,328)	1,473
Comprehensive income	695	1,983
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	13	(147)
Comprehensive income attributable to controlling interests	708	1,836
Preference share dividends	(95)	(89)
Comprehensive income attributable to common shareholders	613	1,747

*See accompanying notes to the interim consolidated financial statements.*



# ENBRIDGE INC.

## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31,	
	2019	2018
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>		
Preference shares (Note 5)		
Balance at beginning and end of period	7,747	7,747
Common shares (Note 5)		
Balance at beginning of period	64,677	50,737
Dividend Reinvestment and Share Purchase Plan	—	374
Shares issued on exercise of stock options	51	16
Balance at end of period	64,728	51,127
Additional paid-in capital		
Balance at beginning of period	—	3,194
Stock-based compensation	4	17
Options exercised	(43)	(6)
Dilution gain on Spectra Energy Partners, LP restructuring	—	1,136
Change in reciprocal interest	109	—
Dilution loss and other	2	(28)
Balance at end of period	72	4,313
Deficit		
Balance at beginning of period	(5,538)	(2,468)
Earnings attributable to controlling interests	1,986	534
Preference share dividends	(95)	(89)
Dividends paid to reciprocal shareholder	5	7
Modified retrospective adoption of ASC 606 Revenue from Contracts with Customers	—	(86)
Redemption value adjustment attributable to redeemable noncontrolling interests	—	120
Other	2	—
Balance at end of period	(3,640)	(1,982)
Accumulated other comprehensive income/(loss) (Note 9)		
Balance at beginning of period	2,672	(973)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	(1,278)	1,302
Other	55	—
Balance at end of period	1,449	329
Reciprocal shareholding		
Balance at beginning of period	(88)	(102)
Change in reciprocal interest	37	—
Balance at end of period	(51)	(102)
Total Enbridge Inc. shareholders' equity	70,305	61,432
Noncontrolling interests		
Balance at beginning of period	3,965	7,597
Earnings attributable to noncontrolling interests	37	23
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gain/(loss) on cash flow hedges	(1)	4
Foreign currency translation adjustments	(49)	152
Reclassification to earnings of loss on cash flow hedges	—	8
	(50)	164
Comprehensive income attributable to noncontrolling interests	(13)	187
Spectra Energy Partners, LP restructuring	—	(1,486)
Contributions	3	8
Distributions	(46)	(209)
Redemption of preferred shares held by subsidiary (Note 10)	(300)	—
Other	5	(15)
Balance at end of period	3,614	6,082
Total equity	73,919	67,514
Dividends paid per common share	0.738	0.671
Earnings per common share attributable to common shareholders (Note 5)	0.94	0.26
Diluted earnings per common share attributable to common shareholders (Note 5)	0.94	0.26

See accompanying notes to the interim consolidated financial statements.

# ENBRIDGE INC.

## CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2019	2018
<i>(unaudited; millions of Canadian dollars)</i>		
<b>Operating activities</b>		
Earnings	2,023	510
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	840	824
Deferred income tax (recovery)/expense	435	(147)
Changes in unrealized (gain)/loss on derivative instruments, net <i>(Note 11)</i>	(538)	260
Earnings from equity investments	(413)	(335)
Distributions from equity investments	466	320
Impairment of long-lived assets	—	1,062
Other	30	78
Changes in operating assets and liabilities	(667)	622
<b>Net cash provided by operating activities</b>	<b>2,176</b>	<b>3,194</b>
<b>Investing activities</b>		
Capital expenditures	(1,612)	(1,635)
Long-term investments and restricted long-term investments	(565)	(222)
Distributions from equity investments in excess of cumulative earnings	139	57
Additions to intangible assets	(26)	(258)
Affiliate loans, net	(84)	(10)
<b>Net cash used in investing activities</b>	<b>(2,148)</b>	<b>(2,068)</b>
<b>Financing activities</b>		
Net change in short-term borrowings	(154)	(443)
Net change in commercial paper and credit facility draws	2,773	(465)
Debenture and term note issues, net of issue costs	1,195	2,061
Debenture and term note repayments	(1,789)	(996)
Debt extinguishment costs	—	(63)
Contributions from noncontrolling interests	3	8
Distributions to noncontrolling interests	(46)	(209)
Contributions from redeemable noncontrolling interests	—	20
Distributions to redeemable noncontrolling interests	—	(84)
Common shares issued	18	13
Preference share dividends	(90)	(87)
Common share dividends	(1,486)	(764)
Redemption of preferred shares held by subsidiary <i>(Note 10)</i>	(300)	—
Other	(25)	—
<b>Net cash provided by/(used in) financing activities</b>	<b>99</b>	<b>(1,009)</b>
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	(7)	19
<b>Net increase in cash and cash equivalents and restricted cash</b>	<b>120</b>	<b>136</b>
Cash and cash equivalents and restricted cash at beginning of period	637	587
<b>Cash and cash equivalents and restricted cash at end of period</b>	<b>757</b>	<b>723</b>

*See accompanying notes to the interim consolidated financial statements.*

# ENBRIDGE INC.

## CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2019	December 31, 2018
<i>(unaudited; millions of Canadian dollars; number of shares in millions)</i>		
<b>Assets</b>		
Current assets		
Cash and cash equivalents	702	518
Restricted cash	55	119
Accounts receivable and other	6,486	6,517
Accounts receivable from affiliates	92	79
Inventory	1,047	1,339
	<b>8,382</b>	8,572
Property, plant and equipment, net	93,875	94,540
Long-term investments	16,902	16,707
Restricted long-term investments	356	323
Deferred amounts and other assets	9,505	8,558
Intangible assets, net	2,301	2,372
Goodwill	33,895	34,459
Deferred income taxes	1,292	1,374
<b>Total assets</b>	<b>166,508</b>	166,905
<b>Liabilities and equity</b>		
Current liabilities		
Short-term borrowings	870	1,024
Accounts payable and other	7,331	9,863
Accounts payable to affiliates	30	40
Interest payable	573	669
Current portion of long-term debt	4,321	3,259
	<b>13,125</b>	14,855
Long-term debt	60,680	60,327
Other long-term liabilities	9,044	8,834
Deferred income taxes	9,740	9,454
	<b>92,589</b>	93,470
Contingencies <i>(Note 15)</i>		
Equity		
Share capital		
Preference shares	7,747	7,747
Common shares <i>(2,024 and 2,022 outstanding at March 31, 2019 and December 31, 2018, respectively)</i>	64,728	64,677
Additional paid-in capital	72	—
Deficit	(3,640)	(5,538)
Accumulated other comprehensive income <i>(Note 9)</i>	1,449	2,672
Reciprocal shareholding	(51)	(88)
Total Enbridge Inc. shareholders' equity	70,305	69,470
Noncontrolling interests	3,614	3,965
	<b>73,919</b>	73,435
<b>Total liabilities and equity</b>	<b>166,508</b>	166,905

See accompanying notes to the interim consolidated financial statements.

# NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(*unaudited*)

## 1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. ("we", "our", "us" and "Enbridge") have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. They do not include all of the information and notes required by U.S. GAAP for annual consolidated financial statements and should therefore be read in conjunction with our audited updated consolidated financial statements and notes for the year ended December 31, 2018, as filed on Form 8-K with the Securities and Exchange Commission on May 10, 2019. In the opinion of management, the interim consolidated financial statements contain all normal recurring adjustments necessary to present fairly our financial position, results of operations and cash flows for the interim periods reported. These interim consolidated financial statements follow the same significant accounting policies as those included in our audited updated consolidated financial statements for the year ended December 31, 2018, except for the adoption of new standards (*Note 2*). Amounts are stated in Canadian dollars unless otherwise noted.

Our operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility businesses, as well as other factors such as the supply of and demand for crude oil and natural gas, and may not be indicative of annual results.

## 2. CHANGES IN ACCOUNTING POLICIES

### ADOPTION OF NEW STANDARDS

#### Cloud Computing Arrangements

Effective January 1, 2019, we adopted Accounting Standards Update (ASU) 2018-15 on a prospective basis. The new standard was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement (CCA) that is a service contract. The ASU specifies that an entity would apply Accounting Standards Codification (ASC) 350-40, Internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. The amendments in the update also require that the capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service, in addition to specifying that the capitalized costs must be presented on the same balance sheet line as the prepayment of fees related to the hosting arrangement. The ASU requires similar consistency in classifications from a cash flow statement perspective. The adoption of this ASU did not have a material impact on our consolidated financial statements.

#### Improvements to Accounting for Hedging Activities

Effective January 1, 2019, we adopted ASU 2017-12 on a modified retrospective basis. The new standard was issued with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The amendments allow cash flow hedging of contractually specified components in financial and non-financial items. As a result of the new standard, hedge ineffectiveness will no longer be measured or recorded, and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

### **Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium**

Effective January 1, 2019, we adopted ASU 2017-08 on a modified retrospective basis. The new standard was issued with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

### **Recognition of Leases**

Effective January 1, 2019 we adopted ASU 2016-02 Leases (Topic 842) using the modified retrospective approach.

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 on the statement 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 as is applied for other long-lived assets, as described under the Impairment section of the Significant Accounting Policies Note 2 in the annual consolidated financial statements.

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.

In adopting Topic 842, we elected the package of practical expedients permitted under the transition guidance. The election to apply the package of practical expedients allows an entity to not apply the new lease standard to the prior year comparative periods in the year of adoption. The application of the package of practical expedients also permits entities not to reassess whether any expired or existing contracts contain leases in accordance with the new guidance, lease classifications, and whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements on existing agreements that had commenced prior to January 1, 2019.

On January 1, 2019, ROU assets and corresponding lease liabilities of \$771 million were recorded in connection with the adoption of Topic 842. When added to the \$85 million of pre-existing liabilities relating to operating leases for which we no longer utilize the leased assets, total lease liabilities at January 1, 2019 were \$856 million. All lease liabilities were measured using a weighted average discount rate of 4.32%. The adoption of this standard had no impact to the Consolidated Statements of Earnings, Comprehensive Income, Changes in Equity or Cash Flows during the period.

## **FUTURE ACCOUNTING POLICY CHANGES**

### **Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers**

In November 2018, ASU 2018-18 was issued to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update is effective January 1, 2020 and early adoption is permitted. We are currently assessing the impact of the new standard on our consolidated financial statements.

### **Improvements to Related Party Guidance for Variable Interest Entities**

ASU 2018-17 was issued in October 2018 to improve the related party guidance on determining whether fees paid to decision makers and service providers (“decision-maker fees”) are variable interests. Under the new guidance, reporting entities must consider indirect interests held through related parties in common control arrangements on a proportionate basis, rather than as the equivalent of a direct interest in its entirety, when determining if a decision maker’s fees constitute a variable interest. The accounting update is effective January 1, 2020 and must be applied on a retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

### **Disclosure Effectiveness**

In August 2018, the Financial Accounting Standards Board issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. We are currently assessing the impact of the new standard on our consolidated financial statements.

ASU 2018-13 was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. We are currently assessing the impact of the new standard on our consolidated financial statements.

### **Accounting for Credit Losses**

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delay the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity will recognize as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses. Both accounting updates are effective January 1, 2020. We are currently assessing the impact of the new standard on our consolidated financial statements.

### 3. REVENUES

Effective January 1, 2019, we renamed the Green Power and Transmission segment to Renewable Power Generation and Transmission. The presentation of the prior years' tables has been revised in order to align with the current presentation.

#### REVENUE FROM CONTRACTS WITH CUSTOMERS

##### Major Products and Services

Three months ended March 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>							
Transportation revenues	2,214	1,137	249	—	—	—	3,600
Storage and other revenues	27	53	54	—	—	—	134
Gas gathering and processing revenues	—	116	—	—	—	—	116
Gas distribution revenue	—	—	1,856	—	—	—	1,856
Electricity and transmission revenues	—	—	—	50	—	—	50
Total revenue from contracts with customers	2,241	1,306	2,159	50	—	—	5,756
Commodity sales	—	—	—	—	6,632	—	6,632
Other revenues <sup>1,2</sup>	340	10	29	102	6	(19)	468
Intersegment revenues	77	2	3	—	35	(117)	—
Total revenues	2,658	1,318	2,191	152	6,673	(136)	12,856

Three months ended March 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>							
Transportation revenues	2,058	952	239	—	—	—	3,249
Storage and other revenues	40	60	66	—	—	—	166
Gas gathering and processing revenues	—	205	—	—	—	—	205
Gas distribution revenues	—	—	1,926	—	—	—	1,926
Electricity and transmission revenues	—	—	—	57	—	—	57
Commodity sales	—	693	—	—	—	—	693
Total revenue from contracts with customers	2,098	1,910	2,231	57	—	—	6,296
Commodity sales	—	—	—	—	6,575	—	6,575
Other revenues <sup>1,2</sup>	(269)	25	2	100	—	(3)	(145)
Intersegment revenues	80	2	4	—	57	(143)	—
Total revenues	1,909	1,937	2,237	157	6,632	(146)	12,726

<sup>1</sup> Includes mark-to-market gains/(losses) from our hedging program.

<sup>2</sup> Includes revenues from lease contracts, refer to Note 14 Leases.

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

## Contract Balances

	Receivables	Contract Assets	Contract Liabilities
<i>(millions of Canadian dollars)</i>			
Balance as at December 31, 2018	1,929	191	1,297
Balance as at March 31, 2019	2,338	191	1,262

Contract receivables represent the amount of receivables derived from contracts with customers. Contract assets represent the amount of revenues which has been recognized in advance of payments received for performance obligations we have fulfilled (or 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 revenues. Revenues recognized during the three months ended March 31, 2019 included in contract liabilities at the beginning of the period is \$92 million. Increases in contract liabilities from cash received, net of amounts recognized as revenues during the three months ended March 31, 2019 were \$74 million.

### Performance Obligations

There was no material revenues recognized in the three months ended March 31, 2019 from performance obligations satisfied in previous periods.

### Revenues to be Recognized from Unfulfilled Performance Obligations

Total revenues from performance obligations expected to be fulfilled in future periods is \$66.7 billion, of which \$5.3 billion and \$5.8 billion is expected to be recognized during the nine months ending December 31, 2019, and the year ending December 31, 2020, respectively.

The revenues excluded from the amounts above based on optional exemptions available under 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 for revenues 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.



## Recognition and Measurement of Revenues

<b>Three months ended March 31, 2019</b>	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
<i>(millions of Canadian dollars)</i>						
Revenues from products transferred at a point in time <sup>1</sup>	—	—	17	—	—	17
Revenues from products and services transferred over time <sup>2</sup>	2,241	1,306	2,142	50	—	5,739
<b>Total revenue from contracts with customers</b>	<b>2,241</b>	<b>1,306</b>	<b>2,159</b>	<b>50</b>	<b>—</b>	<b>5,756</b>

<b>Three months ended March 31, 2018</b>	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
<i>(millions of Canadian dollars)</i>						
Revenues from products transferred at a point in time <sup>1</sup>	—	693	25	—	—	718
Revenues from products and services transferred over time <sup>2</sup>	2,098	1,217	2,206	57	—	5,578
<b>Total revenue from contracts with customers</b>	<b>2,098</b>	<b>1,910</b>	<b>2,231</b>	<b>57</b>	<b>—</b>	<b>6,296</b>

<sup>1</sup> Revenues from sales of crude oil, natural gas and NGLs.

<sup>2</sup> Revenues 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.

## 4. SEGMENTED INFORMATION

<b>Three months ended March 31, 2019</b>	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>							
Revenues	2,658	1,318	2,191	152	6,673	(136)	12,856
Commodity and gas distribution costs	(6)	—	(1,264)	(1)	(6,629)	128	(7,772)
Operating and administrative	(801)	(513)	(294)	(42)	(33)	58	(1,625)
Income/(loss) from equity	197	197	11	14	(7)	1	413
Other income	24	18	18	1	2	197	260
Earnings before interest, income	2,072	1,020	662	124	6	248	4,132
Depreciation and amortization							(840)
Interest expense							(685)
Income tax expense							(584)
<b>Earnings</b>							<b>2,023</b>
Capital expenditures <sup>1</sup>	1,020	394	173	14	1	25	1,627

<b>Three months ended March 31, 2018</b>	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>							
Revenues	1,909	1,937	2,237	157	6,632	(146)	12,726
Commodity and gas distribution costs	(4)	(620)	(1,388)	—	(6,455)	146	(8,321)
Operating and administrative	(747)	(507)	(248)	(30)	(12)	(97)	(1,641)
Impairment of long-lived assets	(144)	(913)	—	—	—	(5)	(1,062)
Income from equity investments	131	208	17	(25)	4	—	335
Other income/(expense)	11	21	18	7	—	(177)	(120)
Earnings/(loss) before interest, income taxes, and depreciation and amortization	1,156	126	636	109	169	(279)	1,917
Depreciation and amortization							(824)
Interest expense							(656)
Income tax recovery							73
Earnings							510
Capital expenditures <sup>1</sup>	615	825	183	14	—	6	1,643

<sup>1</sup> Includes allowance for equity funds used during construction.

## 5. EARNINGS PER COMMON SHARE AND DIVIDENDS PER SHARE

### BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of 6 million and 13 million for the three months ended March 31, 2019 and 2018, resulting from our reciprocal investment in Noverco Inc.

### DILUTED

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options 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:

	Three months ended March 31,	
	<b>2019</b>	2018
<i>(number of common shares in millions)</i>		
Weighted average shares outstanding	<b>2,016</b>	1,685
Effect of dilutive options	<b>3</b>	4
Diluted weighted average shares outstanding	<b>2,019</b>	1,689

For the three months ended March 31, 2019 and 2018, 10,495,198 and 29,882,142, respectively, anti-dilutive stock options with a weighted average exercise price of \$55.32 and \$49.80, respectively, were excluded from the diluted earnings per common share calculation.

## DIVIDENDS PER SHARE

On April 23, 2019, our Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2019, to shareholders of record on May 15, 2019.

	Dividend per share
Common Shares	\$0.73800
Preference Shares, Series A	\$0.34375
Preference Shares, Series B	\$0.21340
Preference Shares, Series C <sup>1</sup>	\$0.25395
Preference Shares, Series D	\$0.27875
Preference Shares, Series F	\$0.29306
Preference Shares, Series H	\$0.27350
Preference Shares, Series J	US\$0.30540
Preference Shares, Series L	US\$0.30993
Preference Shares, Series N	\$0.31788
Preference Shares, Series P <sup>2</sup>	\$0.27369
Preference Shares, Series R	\$0.25000
Preference Shares, Series 1	US\$0.37182
Preference Shares, Series 3	\$0.25000
Preference Shares, Series 5 <sup>3</sup>	US\$0.33596
Preference Shares, Series 7 <sup>4</sup>	\$0.27806
Preference Shares, Series 9	\$0.27500
Preference Shares, Series 11	\$0.27500
Preference Shares, Series 13	\$0.27500
Preference Shares, Series 15	\$0.27500
Preference Shares, Series 17	\$0.32188
Preference Shares, Series 19	\$0.30625

*1 The quarterly dividend per share paid on Series C was decreased to \$0.25395 from \$0.25459 on March 1, 2019, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.*

*2 The quarterly dividend per share paid on Series P was increased to \$0.27369 from \$0.25000 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

*3 The quarterly dividend per share paid on Series 5 was increased to US\$0.33596 from US\$0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

*4 The quarterly dividend per share paid on Series 7 was increased to \$0.27806 from \$0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

## 6. ACQUISITIONS AND DISPOSITIONS

### ACQUISITIONS

In January 2019, through our wholly-owned subsidiary Enbridge Pipelines (Athabasca) Inc., we acquired 75 kilometers of existing pipeline and tankage infrastructure (collectively, the Cheecham Assets) from Athabasca Oil Corporation for cash consideration of approximately \$265 million, all of which was allocated to property, plant and equipment. The Cheecham Assets are a part of our Liquids Pipelines segment. The cash consideration is included in capital expenditures on our Consolidated Statements of Cash Flows for the three months ended March 31, 2019.

## ASSETS HELD FOR SALE

### Enbridge Gas New Brunswick

In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB) to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for a cash purchase price of \$331 million, subject to customary closing adjustments. EGNB operates and maintains natural gas distribution pipelines in southern New Brunswick, and its related assets are included in our Gas Distribution segment. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2019.

### Canadian Natural Gas Gathering and Processing Businesses

On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately \$4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations. On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately \$2.5 billion. Subject to certain regulatory approvals and customary closing conditions, the sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately \$1.8 billion.

### Line 10 Crude Oil Pipeline

In the first quarter of 2018, we satisfied the conditions 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 wholly-owned subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. (EEP), own the Canadian and United States portions of Line 10. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2019.

### St. Lawrence Gas Company, Inc.

In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. for cash proceeds of approximately \$94 million (US\$70 million). Subject to regulatory approval and certain pre-closing conditions, the transaction is expected to close in 2019.

The table below summarizes the presentation of net assets held for sale in our Consolidated Statements of Financial Position:

	March 31, 2019	December 31, 2018
<i>(millions of Canadian dollars)</i>		
Accounts receivable and other (current assets held for sale)	101	117
Deferred amounts and other assets (long-term assets held for sale) <sup>1</sup>	2,415	2,383
Accounts payable and other (current liabilities held for sale)	(55)	(63)
Other long-term liabilities (long-term liabilities held for sale)	(99)	(96)
Net assets held for sale	2,362	2,341

<sup>1</sup> Included within Deferred amounts and other assets at March 31, 2019 and December 31, 2018 respectively is property, plant and equipment of \$2.2 billion and \$2.1 billion.

## 7. VARIABLE INTEREST ENTITIES

### Gray Oak Holdings LLC

In December 2018, Enbridge acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings LLC (Gray Oak Holdings), which will construct and operate the Gray Oak crude oil pipeline from Texas to the Gulf coast of the United States.

Gray Oak Holdings is a variable interest entity (VIE) as it does not have sufficient equity at risk to finance its activities and requires subordinated financial support from Enbridge and other partners. We have determined that we do not have the power to direct the activities of Gray Oak Holdings that most significantly impact the VIE's economic performance. Specifically, the power to direct the activities of the VIE is shared amongst the partners. Each partner has representatives that make up an executive committee that makes the significant decisions for the VIE and none of the partners may make major decisions unilaterally. Therefore, the VIE is accounted for as an unconsolidated VIE.

As at March 31, 2019 and December 31, 2018, the carrying amount of the investment in Gray Oak Holdings was \$455 million and nil, respectively. Enbridge's maximum exposure to loss as at March 31, 2019 was approximately \$931 million and primarily consists of our portion of the project construction costs.

On March 29, 2019, we and our partners of the Gray Oak Holdings investment executed a loan agreement to loan up to a maximum of US\$1,230 million to the investment to finance the construction of the Gray Oak crude oil pipeline. The amount committed by us is US\$280 million, which is proportionate to our effective ownership interest. Loans under this agreement are due on March 31, 2022, with early repayment permitted.

## 8. DEBT

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and EEP (together, 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 guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. See *Note 16 - Condensed Consolidating Financial Information* for further discussion.

### CREDIT FACILITIES

The following table provides details of our committed credit facilities as at March 31, 2019:

	Maturity	Total Facilities	Draws <sup>1</sup>	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2019-2024	6,137	4,319	1,818
Enbridge (U.S.) Inc.	2021-2024	7,348	5,252	2,096
Enbridge Pipelines Inc.	2020	3,000	1,513	1,487
Enbridge Gas Inc.	2019-2021	2,017	879	1,138
<b>Total committed credit facilities</b>		<b>18,502</b>	<b>11,963</b>	<b>6,539</b>

<sup>1</sup> Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, EGI, EEP and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and EGI. As a result, our total credit facility availability increased by approximately \$444 million.

In addition to the committed credit facilities noted above, we maintain \$800 million of uncommitted demand credit facilities, of which \$516 million were unutilized as at March 31, 2019. As at December 31, 2018, we had \$807 million of uncommitted credit facilities, of which \$548 million were 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 2020 to 2024.

As at March 31, 2019 and December 31, 2018, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year of \$10,689 million and \$7,967 million, 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 three months ended March 31, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
<i>(millions of Canadian dollars)</i>			
Enbridge Pipelines Inc.	February 2019	3.52% medium-term notes due February 2029	\$600
	February 2019	4.33% medium-term notes due February 2049	\$600

### LONG-TERM DEBT REPAYMENTS

During the three months ended March 31, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
<i>(millions of Canadian dollars, unless otherwise stated)</i>			
Enbridge Inc.	Repayment		
	February 2019	4.10% medium-term notes	\$300
Enbridge Energy Partners, L.P.	Redemption		
	February 2019	8.05% fixed/floating rate junior subordinated notes due 2067	US\$400
	Repayment		
	March 2019	9.88% senior notes	US\$500
Westcoast Energy Inc.	Repayment		
	January 2019	5.60% medium-term notes	\$250
	January 2019	5.60% medium-term notes	\$50

### SUBORDINATED TERM NOTES

As at March 31, 2019 and December 31, 2018, our fixed-to-floating subordinated term notes had a principal value of \$6,675 million and \$7,317 million, respectively.

## FAIR VALUE ADJUSTMENT

As at March 31, 2019, the net fair value adjustment for total debt assumed in the Spectra Energy merger transaction was \$930 million. During the three months ended March 31, 2019, the amortization of the fair value adjustment, recorded as a reduction to Interest expense in the Consolidated Statements of Earnings, was \$17 million.

## 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 March 31, 2019, we were in compliance with all debt covenants.

## 9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated Other Comprehensive Income (AOCI) attributable to our common shareholders for the three months ended March 31, 2019 and 2018 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
<i>(millions of Canadian dollars)</i>						
Balance as at January 1, 2019	(770)	(598)	4,323	34	(317)	2,672
Other comprehensive income/(loss) retained in AOCI	(312)	109	(1,242)	8	—	(1,437)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts <sup>1</sup>	32	—	—	—	—	32
Foreign exchange contracts <sup>3</sup>	2	—	—	—	—	2
Other contracts <sup>4</sup>	(9)	—	—	—	—	(9)
Amortization of pension and OPEB actuarial loss and prior service costs <sup>5</sup>	—	—	—	—	53	53
	(287)	109	(1,242)	8	53	(1,359)
Tax impact						
Income tax on amounts retained in AOCI	121	(15)	—	4	—	110
Income tax on amounts reclassified to earnings	(14)	—	—	—	(15)	(29)
	107	(15)	—	4	(15)	81
Other	—	—	—	—	55	55
Balance as at March 31, 2019	(950)	(504)	3,081	46	(224)	1,449

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
<i>(millions of Canadian dollars)</i>						
Balance as at January 1, 2018	(644)	(139)	77	10	(277)	(973)
Other comprehensive income/(loss) retained in AOCI	70	(213)	1,425	2	—	1,284
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts <sup>1</sup>	28	—	—	—	—	28
Commodity contracts <sup>2</sup>	(1)	—	—	—	—	(1)
Foreign exchange contracts <sup>3</sup>	4	—	—	—	—	4
Other contracts <sup>4</sup>	9	—	—	—	—	9
Amortization of pension and OPEB actuarial loss and prior service costs <sup>5</sup>	—	—	—	—	(38)	(38)
	110	(213)	1,425	2	(38)	1,286
Tax impact						
Income tax on amounts retained in AOCI	(9)	29	—	8	—	28
Income tax on amounts reclassified to earnings	(11)	—	—	—	(1)	(12)
	(20)	29	—	8	(1)	16
Balance as at March 31, 2018	(554)	(323)	1,502	20	(316)	329

<sup>1</sup> Reported within Interest expense in the Consolidated Statements of Earnings.

<sup>2</sup> Reported within Commodity costs in the Consolidated Statements of Earnings.

<sup>3</sup> Reported within Other income/(expense) in the Consolidated Statements of Earnings.

<sup>4</sup> Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

<sup>5</sup> These components are included in the computation of net periodic benefit costs and are reported within Other income/(expense) in the Consolidated Statements of Earnings.

## 10. NONCONTROLLING INTERESTS

### Preferred Shares Redemption

On March 20, 2019, Westcoast Energy Inc. exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 ("Series 7 Shares") and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 ("Series 8 Shares") at a price of \$25.00 per Series 7 Share and \$25.00 per Series 8 Share, respectively, for a total payment of \$300 million. In addition, payment of \$4 million was made for all accrued and unpaid dividends. As a result, we recorded a \$300 million decrease in Noncontrolling interests.

## 11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

### MARKET RISK

Our earnings, cash flows and Other Comprehensive Income (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 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 United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States 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. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.8%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of the 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 the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As at March 31, 2019, 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 within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3%.

We also 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.

### **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

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our 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 maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
<b>March 31, 2019</b>						
<i>(millions of Canadian dollars)</i>						
Accounts receivable and other						
Foreign exchange contracts	—	—	26	26	(26)	—
Interest rate contracts	7	—	—	7	—	7
Commodity contracts	1	—	171	172	(77)	95
	<b>8</b>	<b>—</b>	<b>197</b>	<b>205</b>	<b>(103)</b>	<b>102</b>
Deferred amounts and other assets						
Foreign exchange contracts	13	—	37	50	(36)	14
Interest rate contracts	—	—	—	—	—	—
Commodity contracts	17	—	18	35	(22)	13
Other contracts	1	—	1	2	—	2
	<b>31</b>	<b>—</b>	<b>56</b>	<b>87</b>	<b>(58)</b>	<b>29</b>
Accounts payable and other						
Foreign exchange contracts	(5)	—	(501)	(506)	26	(480)
Interest rate contracts	(150)	—	—	(150)	—	(150)
Commodity contracts	—	—	(289)	(289)	77	(212)
Other contracts	—	—	(1)	(1)	—	(1)
	<b>(155)</b>	<b>—</b>	<b>(791)</b>	<b>(946)</b>	<b>103</b>	<b>(843)</b>
Other long-term liabilities						
Foreign exchange contracts	—	(14)	(1,666)	(1,680)	36	(1,644)
Interest rate contracts	(374)	—	—	(374)	—	(374)
Commodity contracts	—	—	(152)	(152)	22	(130)
Other contracts	—	—	—	—	—	—
	<b>(374)</b>	<b>(14)</b>	<b>(1,818)</b>	<b>(2,206)</b>	<b>58</b>	<b>(2,148)</b>
Total net derivative asset/(liability)						
Foreign exchange contracts	8	(14)	(2,104)	(2,110)	—	(2,110)
Interest rate contracts	(517)	—	—	(517)	—	(517)
Commodity contracts	18	—	(252)	(234)	—	(234)
Other contracts	1	—	—	1	—	1
	<b>(490)</b>	<b>(14)</b>	<b>(2,356)</b>	<b>(2,860)</b>	<b>—</b>	<b>(2,860)</b>

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
<i>(millions of Canadian dollars)</i>						
Accounts receivable and other						
Foreign exchange contracts	—	—	47	47	(37)	10
Interest rate contracts	22	—	—	22	(2)	20
Commodity contracts	2	—	427	429	(114)	315
	24	—	474	498	(153)	345
Deferred amounts and other assets						
Foreign exchange contracts	23	—	39	62	(39)	23
Interest rate contracts	5	—	—	5	—	5
Commodity contracts	19	—	33	52	(21)	31
	47	—	72	119	(60)	59
Accounts payable and other						
Foreign exchange contracts	(5)	—	(610)	(615)	37	(578)
Interest rate contracts	(163)	—	(178)	(341)	2	(339)
Commodity contracts	—	—	(273)	(273)	114	(159)
Other contracts	(1)	—	(4)	(5)	—	(5)
	(169)	—	(1,065)	(1,234)	153	(1,081)
Other long-term liabilities						
Foreign exchange contracts	(1)	(15)	(2,196)	(2,212)	39	(2,173)
Interest rate contracts	(201)	—	—	(201)	—	(201)
Commodity contracts	—	—	(178)	(178)	21	(157)
Other contracts	(1)	—	(1)	(2)	—	(2)
	(203)	(15)	(2,375)	(2,593)	60	(2,533)
Total net derivative asset/(liability)						
Foreign exchange contracts	17	(15)	(2,720)	(2,718)	—	(2,718)
Interest rate contracts	(337)	—	(178)	(515)	—	(515)
Commodity contracts	21	—	9	30	—	30
Other contracts	(2)	—	(5)	(7)	—	(7)
	(301)	(15)	(2,894)	(3,210)	—	(3,210)

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

<b>March 31, 2019</b>	2019	2020	2021	2022	2023	Thereafter <sup>1</sup>
Foreign exchange contracts - United States dollar forwards - purchase ( <i>millions of United States dollars</i> )	895	1	—	—	—	—
Foreign exchange contracts - United States dollar forwards - sell ( <i>millions of United States dollars</i> )	3,839	4,893	3,608	1,944	1,804	1,856
Foreign exchange contracts - British pound (GBP) forwards - sell ( <i>millions of GBP</i> )	86	25	27	28	29	120
Foreign exchange contracts - Euro forwards - purchase ( <i>millions of Euro</i> )	168	—	—	—	—	—
Foreign exchange contracts - Euro forwards - sell ( <i>millions of Euro</i> )	—	23	94	94	92	606
Foreign exchange contracts - Japanese yen forwards - purchase ( <i>millions of yen</i> )	32,662	—	—	20,000	—	—
Interest rate contracts - short-term pay fixed rate ( <i>millions of Canadian dollars</i> )	6,629	6,178	4,142	407	48	156
Interest rate contracts - long-term receive fixed rate ( <i>millions of Canadian dollars</i> )	—	—	—	—	—	—
Interest rate contracts - long-term debt pay fixed rate ( <i>millions of Canadian dollars</i> )	2,537	3,142	1,584	—	—	—
Equity contracts ( <i>millions of Canadian dollars</i> )	32	20	—	—	—	—
Commodity contracts - natural gas ( <i>billions of cubic feet</i> )	(75)	(15)	—	(84)	1	—
Commodity contracts - crude oil ( <i>millions of barrels</i> )	4	(2)	—	—	—	—
Commodity contracts - NGL ( <i>millions of barrels</i> )	1	—	—	—	—	—
Commodity contracts - power ( <i>megawatt per hour (MW/H)</i> )	98	80	(3)	(43)	(43)	(43)

<sup>1</sup> As at March 31, 2019, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2024 through 2025.

## 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:

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	(10)	21
Interest rate contracts	(296)	100
Commodity contracts	(3)	(2)
Other contracts	12	(14)
Net investment hedges		
Foreign exchange contracts	1	16
	(296)	121
Amount of (gain)/loss reclassified from AOCI to earnings		
Foreign exchange contracts <sup>1</sup>	2	(1)
Interest rate contracts <sup>2</sup>	32	40
Commodity contracts <sup>3</sup>	—	(1)
Other contracts <sup>4</sup>	(9)	9
	25	47

<sup>1</sup> Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.

<sup>2</sup> Reported within Interest expense in the Consolidated Statements of Earnings. Effective January 1, 2019 hedge ineffectiveness will no longer be measured or recorded. See Note 2 Changes in Accounting Policies.

<sup>3</sup> Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

<sup>4</sup> Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a loss of \$36 million of AOCI related to unrealized 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 33 months as at March 31, 2019.

### Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings.

	Three months ended March 31,	
	2019 <sup>1</sup>	2018
<i>(millions of Canadian dollars)</i>		
Unrealized gain/(loss) on derivative	—	(8)
Unrealized gain/(loss) on hedged item	—	8
Realized gain/(loss) on derivative	—	(3)
Realized gain/(loss) on hedged item	—	3

<sup>1</sup> For the three months ended March 31, 2019, there are no outstanding fair value hedges.

## Non-Qualifying Derivatives

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

	Three months ended	
	March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Foreign exchange contracts <sup>1</sup>	616	(424)
Interest rate contracts <sup>2</sup>	178	(2)
Commodity contracts <sup>3</sup>	(261)	175
Other contracts <sup>4</sup>	5	(9)
<b>Total unrealized derivative fair value gain/(loss), net</b>	<b>538</b>	<b>(260)</b>

<sup>1</sup> For the respective three months ended periods, reported within Transportation and other services revenues (2019 - \$352 million gain; 2018 - \$297 million loss) and Net foreign currency gain/(loss) (2019 - \$264 million gain; 2018 - \$127 million loss) in the Consolidated Statements of Earnings.

<sup>2</sup> Reported as an (increase)/decrease within Interest expense in the Consolidated Statements of Earnings.

<sup>3</sup> For the respective three months ended periods, reported within Transportation and other services revenues (2019 - \$26 million loss; 2018 - \$1 million loss), Commodity sales (2019 - \$642 million loss; 2018 - \$82 million gain), Commodity costs (2019 - \$398 million gain; 2018 - \$84 million gain) and Operating and administrative expense (2019 - \$9 million gain; 2018 - \$10 million gain) in the Consolidated Statements of Earnings.

<sup>4</sup> 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. We also maintain current shelf prospectuses with securities regulators which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. 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 March 31, 2019. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding 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:

	<b>March 31, 2019</b>	December 31, 2018
<i>(millions of Canadian dollars)</i>		
Canadian financial institutions	<b>21</b>	28
United States financial institutions	<b>51</b>	107
European financial institutions	<b>58</b>	84
Asian financial institutions	<b>—</b>	6
Other <sup>1</sup>	<b>132</b>	337
	<b>262</b>	562

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

As at March 31, 2019, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association (ISDA) agreements. We held no cash collateral on derivative asset exposures as at March 31, 2019 and December 31, 2018.

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 EGI, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts 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 classify and provide for receivables older than 30 days as past due. 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 derivative 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 derivatives 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 derivative 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.

**Level 2**

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives 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 derivative. 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 held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

**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 contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. 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:

<b>March 31, 2019</b>	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
<i>(millions of Canadian dollars)</i>				
<b>Financial assets</b>				
Current derivative assets				
Foreign exchange contracts	—	26	—	26
Interest rate contracts	—	7	—	7
Commodity contracts	3	10	159	172
	3	43	159	205
Long-term derivative assets				
Foreign exchange contracts	—	50	—	50
Commodity contracts	—	13	22	35
Other contracts	—	2	—	2
	—	65	22	87
<b>Financial liabilities</b>				
Current derivative liabilities				
Foreign exchange contracts	—	(506)	—	(506)
Interest rate contracts	—	(150)	—	(150)
Commodity contracts	(7)	(16)	(266)	(289)
Other contracts	—	(1)	—	(1)
	(7)	(673)	(266)	(946)
Long-term derivative liabilities				
Foreign exchange contracts	—	(1,680)	—	(1,680)
Interest rate contracts	—	(374)	—	(374)
Commodity contracts	—	(15)	(137)	(152)
	—	(2,069)	(137)	(2,206)
<b>Total net financial liabilities</b>				
Foreign exchange contracts	—	(2,110)	—	(2,110)
Interest rate contracts	—	(517)	—	(517)
Commodity contracts	(4)	(8)	(222)	(234)
Other contracts	—	1	—	1
	(4)	(2,634)	(222)	(2,860)

December 31, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
<i>(millions of Canadian dollars)</i>				
<b>Financial assets</b>				
<b>Current derivative assets</b>				
Foreign exchange contracts	—	47	—	47
Interest rate contracts	—	22	—	22
Commodity contracts	24	45	360	429
	24	114	360	498
<b>Long-term derivative assets</b>				
Foreign exchange contracts	—	62	—	62
Interest rate contracts	—	5	—	5
Commodity contracts	—	30	22	52
	—	97	22	119
<b>Financial liabilities</b>				
<b>Current derivative liabilities</b>				
Foreign exchange contracts	—	(615)	—	(615)
Interest rate contracts	—	(341)	—	(341)
Commodity contracts	(7)	(28)	(238)	(273)
Other contracts	—	(5)	—	(5)
	(7)	(989)	(238)	(1,234)
<b>Long-term derivative liabilities</b>				
Foreign exchange contracts	—	(2,212)	—	(2,212)
Interest rate contracts	—	(201)	—	(201)
Commodity contracts	—	(23)	(155)	(178)
Other contracts	—	(2)	—	(2)
	—	(2,438)	(155)	(2,593)
<b>Total net financial liabilities</b>				
Foreign exchange contracts	—	(2,718)	—	(2,718)
Interest rate contracts	—	(515)	—	(515)
Commodity contracts	17	24	(11)	30
Other contracts	—	(7)	—	(7)
	17	(3,216)	(11)	(3,210)

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

<b>March 31, 2019</b>	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
<i>(fair value in millions of Canadian dollars)</i>						
Commodity contracts - financial <sup>1</sup>						
Natural gas	(18)	Forward gas price	2.55	5.17	3.47	\$/mmbtu <sup>2</sup>
Crude	38	Forward crude price	42.96	166.19	69.21	\$/barrel
Power	(82)	Forward power price	30.79	71.28	50.21	\$/MWH
Commodity contracts - physical <sup>1</sup>						
Natural gas	(125)	Forward gas price	1.22	5.17	2.25	\$/mmbtu <sup>2</sup>
Crude	(37)	Forward crude price	33.12	127.36	76.83	\$/barrel
NGL	2	Forward NGL price	0.17	1.11	0.37	\$/gallon
	(222)					

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, and for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

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

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Level 3 net derivative liability at beginning of period	(11)	(387)
Total gain/(loss)		
Included in earnings <sup>1</sup>	(52)	31
Included in OCI	(3)	(3)
Settlements	(156)	154
Level 3 net derivative liability at end of period	(222)	(205)

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

Our policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at March 31, 2019 or December 31, 2018.

## **FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS**

Our other long-term investments in other entities with no actively quoted prices are classified as Fair Value Measurement Alternative (FVMA) investments and are recorded at cost less impairment (if any), plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. The carrying value of FVMA other long-term investments totaled \$101 million and \$102 million as at March 31, 2019 and December 31, 2018, respectively.

We have Restricted long-term investments held in trust totaling \$356 million and \$323 million as at March 31, 2019 and December 31, 2018, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of \$582 million and \$478 million as at March 31, 2019 and December 31, 2018, respectively. These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.38%. The fair value of this preferred share investment approximates its face value of \$582 million and \$580 million as at March 31, 2019 and December 31, 2018 respectively.

As at March 31, 2019 and December 31, 2018, our long-term debt had a carrying value of \$65.3 billion and \$63.9 billion, respectively, before debt issuance costs and a fair value of \$68.9 billion and \$64.4 billion, respectively. We also have noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at March 31, 2019 and December 31, 2018, the noncurrent notes receivable had a carrying value of \$95 million and \$97 million, respectively, and a fair value of \$95 million and \$97 million, respectively.

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

## **NET INVESTMENT HEDGES**

We have designated a portion of our United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in United States dollar denominated investments and subsidiaries.

During the three months ended March 31, 2019 and 2018, we recognized an unrealized foreign exchange gain of \$108 million and an unrealized foreign exchange loss of \$194 million, respectively, on the translation of United States dollar denominated debt and unrealized gains of \$1 million and \$15 million, respectively, on the change in fair value of our outstanding foreign exchange forward contracts in OCI. During the three months ended March 31, 2019 and 2018, we recognized realized losses of nil and \$23 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and recognized realized losses of nil and \$11 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the three months ended March 31, 2019 and 2018.

## **12. INCOME TAXES**

The effective income tax rates for the three months ended March 31, 2019 and 2018 were 22.4% and (16.7)%, respectively. The period-over-period increase in the effective income tax rate is due to the effects of rate-regulated accounting for income taxes and other permanent items relative to the increase in earnings for the three months ended March 31, 2019. Also contributing to the period-over-period increase in the effective income tax rate was the buy-in of our United States sponsored vehicles which results in Enbridge being taxed on all of our United States sponsored vehicle earnings rather than on just our proportionate share.

### 13. PENSION AND OTHER POSTRETIREMENT BENEFITS

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Service cost	51	65
Interest cost	51	45
Expected return on plan assets	(84)	(82)
Amortization of actuarial loss	8	7
Amortization of prior service costs	(1)	(1)
<b>Net periodic benefit costs</b>	<b>25</b>	<b>34</b>

### 14. LEASES

We incur operating lease expense related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of one month to 29 years.

For the three months ended March 31, 2019, we incurred operating lease expenses of \$28 million. Operating lease expenses are reported under Operating and administrative expenses on the Consolidated Statements of Earnings.

For the three months ended March 31, 2019, operating lease payments to settle lease liabilities were \$31 million. Operating lease payments are reported under operating activities in the Consolidated Statements of Cash Flows.

#### Supplemental Statements of Financial Position Information

	March 31, 2019	January 1, 2019
<i>(millions of Canadian dollars, except lease term and discount rate)</i>		
<b>Operating leases</b>		
Operating lease right-of-use assets, net <sup>1</sup>	745	771
Operating lease liabilities - current <sup>2</sup>	67	86
Operating lease liabilities - long-term <sup>3</sup>	757	770
<b>Total operating lease liabilities</b>	<b>824</b>	<b>856</b>
<b>Weighted average remaining lease term</b>		
Operating leases	14 years	14 years
<b>Weighted average discount rate</b>		
Operating leases	4.3%	4.3%

<sup>1</sup> Right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.

<sup>2</sup> Current lease liabilities are reported under Accounts payable and other in the Consolidated Statements of Financial Position.

<sup>3</sup> Long-term lease liabilities are reported under Other long-term liabilities in the Consolidated Statements of Financial Position.

As at March 31, 2019, we have operating lease commitments as detailed below:

	Operating leases
<i>(millions of Canadian dollars)</i>	
2019 <sup>1</sup>	83
2020	116
2021	94
2022	89
2023	79
Thereafter	663
Total undiscounted lease payments	1,124
Less imputed interest	(300)
<b>Total operating lease commitments</b>	<b>824</b>

<sup>1</sup> For the nine months remaining in the 2019 fiscal year.

## LESSOR

We have operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our leases have remaining lease terms of 9 months to 24 years.

	Three months ended March 31, 2019
<i>(millions of Canadian dollars)</i>	
Operating lease income	64
Variable lease income	100
<b>Total lease income</b>	<b>164</b>

The following table sets out future minimum lease payments expected to be received under lease contracts where we are the lessor:

	Operating leases
<i>(millions of Canadian dollars)</i>	
2019 <sup>1</sup>	192
2020	216
2021	189
2022	186
2023	178
Thereafter	2,395
<b>Total undiscounted lease payments</b>	<b>3,356</b>

<sup>1</sup> For the nine months remaining in the 2019 fiscal year.

## 15. CONTINGENCIES

We and our subsidiaries are involved in 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 by special interest groups. 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 interim 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.

## 16. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, 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 guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships 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, 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 <sup>1</sup>	EEP Notes <sup>2</sup>
Floating Rate Senior Notes due 2020	5.200% Notes due 2020
4.600% Senior Notes due 2021	4.375% Notes due 2020
4.750% Senior Notes due 2024	4.200% Notes due 2021
3.500% Senior Notes due 2025	5.875% Notes due 2025
3.375% Senior Notes due 2026	5.950% Notes due 2033
5.950% Senior Notes due 2043	6.300% Notes due 2034
4.500% Senior Notes due 2045	7.500% Notes due 2038
	5.500% Notes due 2040
	7.375% Notes due 2045

<sup>1</sup> As at March 31, 2019, the aggregate outstanding principal amount of SEP notes was approximately US\$3.9 billion.

<sup>2</sup> As at March 31, 2019, the aggregate outstanding principal amount of EEP notes was approximately US\$4.0 billion.

## Enbridge Notes under Guarantees

USD Denominated <sup>1</sup>	CAD Denominated <sup>2</sup>
Senior Floating Rate Notes due 2020	Senior Floating Rate Notes due 2019
Senior Floating Rate Notes due 2020	4.770% Senior Notes due 2019
2.900% Senior Notes due 2022	4.530% Senior Notes due 2020
4.000% Senior Notes due 2023	4.850% Senior Notes due 2020
3.500% Senior Notes due 2024	4.260% Senior Notes due 2021
4.250% Senior Notes due 2026	3.160% Senior Notes due 2021
3.700% Senior Notes due 2027	4.850% Senior Notes due 2022
4.500% Senior Notes due 2044	3.190% Senior Notes due 2022
5.500% Senior Notes due 2046	3.940% Senior Notes due 2023
	3.940% Senior Notes due 2023
	3.950% Senior Notes due 2024
	3.200% Senior Notes due 2027
	6.100% Senior Notes due 2028
	7.220% Senior Notes due 2030
	7.200% Senior Notes due 2032
	5.570% Senior Notes due 2035
	5.750% Senior Notes due 2039
	5.120% Senior Notes due 2040
	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.560% Senior Notes due 2064

<sup>1</sup> As at March 31, 2019, the aggregate outstanding principal amount of the Enbridge United States dollar denominated notes was approximately US\$5.9 billion.

<sup>2</sup> As at March 31, 2019, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately \$7.8 billion.

In accordance with Rule 3-10 of the SEC's Regulation S-X, which provides an exemption from the reporting requirements of the Securities Exchange Act of 1934 for subsidiary issuers of guaranteed securities and subsidiary guarantors, in lieu of filing separate financial statements for each of the Partnerships, we have included the accompanying condensed consolidating financial information with separate columns representing the following:

1. Enbridge Inc., the Parent Issuer and Guarantor;
2. SEP, a Subsidiary Issuer and Guarantor;
3. EEP, a Subsidiary Issuer and Guarantor;
4. Subsidiary Non-Guarantors, as defined herein;
5. Consolidating and elimination entries required to consolidate the Parent Issuer and Guarantor and its subsidiaries, including the Subsidiary Issuers and Guarantors, and
6. Enbridge Inc. and subsidiaries on a consolidated basis.

For the purposes of the condensed consolidating financial information only, investments in subsidiaries are accounted for under the equity method. In addition, the Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities. These intercompany investments and related activities eliminate on consolidation and are presented separately only for the purpose of the accompanying Condensed Consolidating Statements.



**Condensed Consolidating Statements of Earnings and Comprehensive Income for the three months ended March 31, 2019**

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
Operating revenues						
Commodity sales	—	—	—	6,632	—	6,632
Gas distribution sales	—	—	—	1,876	—	1,876
Transportation and other services	—	—	—	4,348	—	4,348
Total operating revenues	—	—	—	12,856	—	12,856
Operating Expenses						
Commodity costs	—	—	—	6,565	—	6,565
Gas distribution costs	—	—	—	1,207	—	1,207
Operating and administrative	(34)	2	1	1,656	—	1,625
Depreciation and amortization	15	—	—	825	—	840
Total operating expenses	(19)	2	1	10,253	—	10,237
Operating income/(loss)	19	(2)	(1)	2,603	—	2,619
Income/(loss) from equity investments	59	31	—	382	(59)	413
Equity earnings from consolidated subsidiaries	774	398	263	493	(1,928)	—
Other						
Net foreign currency gain/(loss)	1,221	—	—	(103)	(904)	214
Other, including other income from affiliates	330	—	41	123	(448)	46
Interest expense	(308)	(94)	(158)	(583)	458	(685)
Earnings before income taxes	2,095	333	145	2,915	(2,881)	2,607
Income tax expense	(109)	15	—	(596)	106	(584)
Earnings	1,986	348	145	2,319	(2,775)	2,023
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(37)	(37)
Earnings attributable to controlling interests	1,986	348	145	2,319	(2,812)	1,986
Preference share dividends	(95)	—	—	—	—	(95)
Earnings attributable to common shareholders	1,891	348	145	2,319	(2,812)	1,891
Earnings	1,986	348	145	2,319	(2,775)	2,023
Total other comprehensive income/(loss)	(1,278)	(16)	15	(720)	671	(1,328)
Comprehensive income	708	332	160	1,599	(2,104)	695
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	13	13
Comprehensive income attributable to controlling interests	708	332	160	1,599	(2,091)	708

**Condensed Consolidating Statements of Earnings and Comprehensive Income for the three months ended March 31, 2018**

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
Operating revenues						
Commodity sales	—	—	—	7,268	—	7,268
Gas distribution sales	—	—	—	1,926	—	1,926
Transportation and other services	—	—	—	3,532	—	3,532
<b>Total operating revenues</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>12,726</b>	<b>—</b>	<b>12,726</b>
Operating Expenses						
Commodity costs	—	—	—	6,997	—	6,997
Gas distribution costs	—	—	—	1,324	—	1,324
Operating and administrative	67	1	4	1,569	—	1,641
Depreciation and amortization	14	—	—	810	—	824
Impairment of long-lived assets	—	—	—	1,062	—	1,062
<b>Total operating expenses</b>	<b>81</b>	<b>1</b>	<b>4</b>	<b>11,762</b>	<b>—</b>	<b>11,848</b>
Operating income/(loss)	(81)	(1)	(4)	964	—	878
Income from equity investments	17	34	—	300	(16)	335
Equity earnings from consolidated subsidiaries	707	551	203	608	(2,069)	—
Other						
Net foreign currency gain/(loss)	(199)	2	—	(58)	70	(185)
Other, including other income/(expense) from affiliates	246	1	30	39	(251)	65
Interest expense	(243)	(72)	(136)	(479)	274	(656)
Earnings before income taxes	447	515	93	1,374	(1,992)	437
Income tax recovery/(expense)	87	—	—	(23)	9	73
Earnings	534	515	93	1,351	(1,983)	510
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	24	24
Earnings attributable to controlling interests	534	515	93	1,351	(1,959)	534
Preference share dividends	(89)	—	—	—	—	(89)
Earnings attributable to common shareholders	445	515	93	1,351	(1,959)	445
Earnings	534	515	93	1,351	(1,983)	510
Total other comprehensive income	1,302	19	8	253	(109)	1,473
<b>Comprehensive income</b>	<b>1,836</b>	<b>534</b>	<b>101</b>	<b>1,604</b>	<b>(2,092)</b>	<b>1,983</b>
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(147)	(147)
<b>Comprehensive income attributable to controlling interests</b>	<b>1,836</b>	<b>534</b>	<b>101</b>	<b>1,604</b>	<b>(2,239)</b>	<b>1,836</b>

## Condensed Consolidating Statements of Financial Position as at March 31, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
<b>Assets</b>						
Current assets						
Cash and cash equivalents	—	5	7	690	—	702
Restricted cash	9	—	—	46	—	55
Accounts receivable and other	283	1	—	6,202	—	6,486
Accounts receivable from affiliates	586	—	31	79	(604)	92
Short-term loans receivable from affiliates	3,527	—	3,838	5,871	(13,236)	—
Inventory	—	—	—	1,047	—	1,047
Property, plant and equipment, net	4,405	6	3,876	13,935	(13,840)	8,382
Long-term loans receivable from affiliates	166	—	—	93,709	—	93,875
Investments in subsidiaries	26,504	73	2,472	15,524	(44,573)	—
Long-term investments	78,271	19,741	6,209	15,032	(119,253)	—
Restricted long-term investments	4,619	961	—	14,890	(3,568)	16,902
Deferred amounts and other assets	—	—	—	356	—	356
Intangible assets, net	1,491	1	8	9,412	(1,407)	9,505
Goodwill	219	—	—	2,082	—	2,301
Deferred income taxes	—	—	—	33,895	—	33,895
Total assets	744	—	—	220	328	1,292
	116,419	20,782	12,565	199,055	(182,313)	166,508
<b>Liabilities and equity</b>						
Current liabilities						
Short-term borrowings	—	—	—	870	—	870
Accounts payable and other	756	19	14	6,552	(10)	7,331
Accounts payable to affiliates	935	509	80	(891)	(603)	30
Interest payable	227	25	92	229	—	573
Short-term loans payable to affiliates	426	2,985	2,458	7,367	(13,236)	—
Current portion of long-term debt	2,979	—	668	674	—	4,321
Long-term debt	5,323	3,538	3,312	14,801	(13,849)	13,125
Other long-term liabilities	23,519	5,095	4,565	27,501	—	60,680
Long-term loans payable to affiliates	2,145	8	22	8,276	(1,407)	9,044
Deferred income taxes	15,076	—	1,470	28,027	(44,573)	—
Equity	—	304	—	13,821	(4,385)	9,740
	46,063	8,945	9,369	92,426	(64,214)	92,589
Controlling interests <sup>1</sup>	70,356	11,837	3,196	106,629	(121,713)	70,305
Noncontrolling interests	—	—	—	—	3,614	3,614
Total liabilities and equity	70,356	11,837	3,196	106,629	(118,099)	73,919
	116,419	20,782	12,565	199,055	(182,313)	166,508

<sup>1</sup> Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.

## Condensed Consolidating Statements of Financial Position as at December 31, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
<b>Assets</b>						
Current assets						
Cash and cash equivalents	—	16	—	502	—	518
Restricted cash	9	—	—	110	—	119
Accounts receivable and other	283	15	8	6,211	—	6,517
Accounts receivable from affiliates	726	—	13	(142)	(518)	79
Short-term loans receivable from affiliates	3,943	—	3,689	653	(8,285)	—
Inventory	—	—	—	1,339	—	1,339
	4,961	31	3,710	8,673	(8,803)	8,572
Property, plant and equipment, net	140	—	—	94,400	—	94,540
Long-term loans receivable from affiliates	10,318	73	2,539	1,344	(14,274)	—
Investments in subsidiaries	78,474	19,777	6,363	15,567	(120,181)	—
Long-term investments	4,561	987	—	14,841	(3,682)	16,707
Restricted long-term investments	—	—	—	323	—	323
Deferred amounts and other assets	1,700	9	17	8,558	(1,726)	8,558
Intangible assets, net	234	—	—	2,138	—	2,372
Goodwill	—	—	—	34,459	—	34,459
Deferred income taxes	817	—	—	229	328	1,374
<b>Total assets</b>	<b>101,205</b>	<b>20,877</b>	<b>12,629</b>	<b>180,532</b>	<b>(148,338)</b>	<b>166,905</b>
<b>Liabilities and equity</b>						
Current liabilities						
Short-term borrowings	—	—	—	1,024	—	1,024
Accounts payable and other	2,742	7	34	7,086	(6)	9,863
Accounts payable to affiliates	946	233	56	(677)	(518)	40
Interest payable	283	56	105	225	—	669
Short-term loans payable to affiliates	426	682	—	7,177	(8,285)	—
Current portion of long-term debt	1,853	—	683	723	—	3,259
	6,250	978	878	15,558	(8,809)	14,855
Long-term debt	22,893	7,276	6,943	23,215	—	60,327
Other long-term liabilities	2,428	2	30	8,100	(1,726)	8,834
Long-term loans payable to affiliates	76	—	1,502	12,696	(14,274)	—
Deferred income taxes	—	331	—	13,523	(4,400)	9,454
	31,647	8,587	9,353	73,092	(29,209)	93,470
Equity						
Controlling interests <sup>1</sup>	69,558	12,290	3,276	107,440	(123,094)	69,470
Noncontrolling interests	—	—	—	—	3,965	3,965
	69,558	12,290	3,276	107,440	(119,129)	73,435
<b>Total liabilities and equity</b>	<b>101,205</b>	<b>20,877</b>	<b>12,629</b>	<b>180,532</b>	<b>(148,338)</b>	<b>166,905</b>

<sup>1</sup> Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.

## Condensed Consolidating Statements of Cash Flows for the three months ended March 31, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
<b>Net cash provided by/(used in) operating activities</b>	(415)	232	(1,418)	4,566	(789)	2,176
<b>Investing activities</b>						
Capital expenditures	(24)	—	—	(1,588)	—	(1,612)
Long-term investments and restricted long-term investments	—	(2)	—	(563)	—	(565)
Distributions from equity investments in excess of cumulative earnings	—	7	536	132	(536)	139
Additions to intangible assets	(16)	—	—	(10)	—	(26)
Affiliate loans, net	—	—	—	(84)	—	(84)
Contributions to subsidiaries	(2,331)	—	—	—	2,331	—
Return of share capital from subsidiaries	3,121	—	—	—	(3,121)	—
Advances to affiliates	(19,908)	—	(618)	(21,542)	42,068	—
Repayment of advances to affiliates	3,996	—	382	1,638	(6,016)	—
<b>Net cash provided by/(used in) investing activities</b>	(15,162)	5	300	(22,017)	34,726	(2,148)
<b>Financing activities</b>						
Net change in short-term borrowings	—	—	—	(154)	—	(154)
Net change in commercial paper and credit facility draws	2,312	(2,010)	—	2,471	—	2,773
Debenture and term note issues, net of issue costs	—	—	—	1,195	—	1,195
Debenture and term note repayments	(300)	—	(1,189)	(300)	—	(1,789)
Contributions from noncontrolling interests	—	—	—	—	3	3
Distributions to noncontrolling interests	—	—	—	—	(46)	(46)
Contributions from parents	—	—	—	2,331	(2,331)	—
Distributions to parents	—	(505)	(162)	(3,822)	4,489	—
Redemption of preferred shares	—	—	—	(300)	—	(300)
Common shares issued	18	—	—	—	—	18
Preference share dividends	(90)	—	—	—	—	(90)
Common share dividends	(1,513)	—	—	27	—	(1,486)
Advances from affiliates	15,150	3,498	2,894	20,526	(42,068)	—
Repayment of advances from affiliates	—	(1,226)	(412)	(4,378)	6,016	—
Other	—	(5)	(6)	(14)	—	(25)
<b>Net cash (used in)/provided by financing activities</b>	15,577	(248)	1,125	17,582	(33,937)	99
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	(7)	—	(7)
Net increase/(decrease) in cash and cash equivalents and restricted cash	—	(11)	7	124	—	120
Cash and cash equivalents and restricted cash at beginning of period	9	16	—	612	—	637
Cash and cash equivalents and restricted cash at end of period	9	5	7	736	—	757

## Condensed Consolidating Statements of Cash Flows for the three months ended March 31, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non- Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
<i>(millions of Canadian dollars)</i>						
<b>Net cash (used in)/provided by operating activities</b>	(135)	803	(331)	3,224	(367)	3,194
<b>Investing activities</b>						
Capital expenditures	(5)	—	—	(1,630)	—	(1,635)
Long-term investments and restricted long-term investments	(16)	(5)	—	(217)	16	(222)
Distributions from equity investments in excess of cumulative earnings	336	15	488	42	(824)	57
Additions to intangible assets	(6)	—	—	(252)	—	(258)
Affiliate loans, net	—	—	—	(10)	—	(10)
Contributions to subsidiaries	(69)	(77)	(5)	—	151	—
Advances to affiliates	(401)	—	(496)	(2,233)	3,130	—
Repayment of advances to affiliates	—	506	548	1,890	(2,944)	—
<b>Net cash (used in)/provided by investing activities</b>	(161)	439	535	(2,410)	(471)	(2,068)
<b>Financing activities</b>						
Net change in short-term borrowings	—	—	—	(443)	—	(443)
Net change in commercial paper and credit facility draws	(105)	(756)	(218)	614	—	(465)
Debenture and term note issues, net of issue costs	1,080	—	—	981	—	2,061
Debenture and term note repayments	—	—	—	(996)	—	(996)
Debt extinguishment costs	—	—	—	(63)	—	(63)
Contributions from noncontrolling interests	—	—	—	—	8	8
Distributions to noncontrolling interests	—	—	—	—	(209)	(209)
Contributions from redeemable noncontrolling interests	—	—	—	—	20	20
Distributions to redeemable noncontrolling interests	—	—	—	—	(84)	(84)
Contributions from parents	—	—	—	151	(151)	—
Distributions to parents	—	(453)	(163)	(824)	1,440	—
Common shares issued	13	—	—	—	—	13
Preference share dividends	(87)	—	—	—	—	(87)
Common share dividends	(764)	—	—	—	—	(764)
Advances from affiliates	209	—	2,024	897	(3,130)	—
Repayment of advances from affiliates	(43)	—	(1,847)	(1,054)	2,944	—
<b>Net cash provided by/(used in) financing activities</b>	303	(1,209)	(204)	(737)	838	(1,009)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	19	—	19
Net increase in cash and cash equivalents and restricted cash	7	33	—	96	—	136
Cash and cash equivalents and restricted cash at beginning of period	2	14	—	571	—	587
Cash and cash equivalents and restricted cash at end of period	9	47	—	667	—	723

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Part 1. Item 1. *Financial Statements* of this report, our Annual Report on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission (SEC) on February 15, 2019, and our audited updated consolidated financial statements and accompanying footnotes for the year ended December 31, 2018, as filed on Form 8-K with the SEC on May 10, 2019.

### RECENT DEVELOPMENT - STATE OF MINNESOTA PERMITTING TIMELINE FOR U.S. LINE 3 REPLACEMENT PROGRAM

On March 1, 2019 we announced that the State of Minnesota provided the permitting timelines for its agencies' remaining environmental permits for the U.S. L3R Program. The permitting timeline indicates that the certifications on all remaining State of Minnesota permits will be provided by November 2019. We anticipate that the remaining Federal permits will be finalized approximately 30 to 60 days thereafter. In light of this updated permitting timeline, we are developing a revised construction schedule and related cost estimates for the U.S. L3R Program, and now expect an in-service date during the second half of 2020. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

### RESULTS OF OPERATIONS

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars, except per share amounts)</i>		
<b>Segment earnings/(loss) before interest, income taxes and depreciation and amortization</b>		
Liquids Pipelines	2,072	1,156
Gas Transmission and Midstream	1,020	126
Gas Distribution	662	636
Renewable Power Generation and Transmission	124	109
Energy Services	6	169
Eliminations and Other	248	(279)
Depreciation and amortization	(840)	(824)
Interest expense	(685)	(656)
Income tax (expense)/recovery	(584)	73
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(37)	24
Preference share dividends	(95)	(89)
Earnings attributable to common shareholders	1,891	445
Earnings per common share	0.94	0.26
Diluted earnings per common share	0.94	0.26

## EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

Earnings Attributable to Common Shareholders were positively impacted by \$1,181 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- the absence in 2019 of a loss of \$913 million (\$701 million after-tax attributable to us) in 2018 on Midcoast Operating, L.P. and its subsidiaries (MOLP) resulting from a revision to the fair value of the assets held for sale based on the sale price;
- the absence in 2019 of a loss of \$144 million (\$85 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline, which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell;
- a non-cash, unrealized derivative fair value gain of \$436 million (\$317 million after-tax attributable to us) in 2019, compared with a loss of \$277 million (\$146 million after-tax attributable to us) in the corresponding 2018 period, 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 and commodity prices risks; and
- employee severance, transition and transformation costs of \$44 million (\$42 million after-tax attributable to us) in 2019, compared with \$97 million (\$96 million after-tax attributable to us) in the corresponding 2018 period; partially offset by
- the absence in 2019 of a gain of \$63 million after-tax in 2018 that resulted from the impact of the Tax Cuts and Jobs Act on our United States Renewable Power Generation and Transmission assets.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of a comprehensive long-term economic hedging program to mitigate interest rate, 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 financial 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 \$265 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to a higher International Joint Tariff (IJT) Benchmark Toll and higher throughput driven by an increase in supply and continuous capacity optimization;
- contributions from new gas transmission assets placed into service in 2018;
- increased earnings from our Gas Distribution segment due to colder weather experienced in our franchise areas, higher distribution rates and customer base, and the absence of forecasted earnings sharing in 2019;
- increased earnings from our Energy Services segment due to the widening of certain location differentials during the second half of 2018, which increased opportunities to generate profitable margins that were realized during the first quarter of 2019; and
- the net favorable effect of translating United States dollar EBITDA at a higher Canadian to United States dollar average exchange rate (Average Exchange Rate) of \$1.33 in 2019 compared with \$1.26 in 2018, partially offset by realized losses arising from our foreign exchange risk management program.

The positive business factors above were partially offset by the following:

- the absence in 2019 of earnings from MOLP and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in 2018; and
- higher income tax expense driven by higher earnings and a higher effective income tax rate partly due to the buy-in of our United States sponsored vehicles in the fourth quarter of 2018.



## BUSINESS SEGMENTS

### LIQUIDS PIPELINES

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings before interest, income taxes and depreciation and amortization	2,072	1,156

#### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

EBITDA was positively impacted by \$814 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$343 million in 2019 compared with a loss of \$298 million in 2018 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 and commodity price risks; and
- the absence in 2019 of a loss of \$144 million in 2018 related to Line 10, which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell.

After taking into consideration the factors above, the remaining \$102 million increase is primarily explained by the following significant business factors:

- a higher IJT Benchmark Toll of US\$4.15 in 2019 compared with US\$4.07 in 2018;
- higher Mainline System ex-Gretna throughput of 2,717 thousands of barrels per day (kbpd) in 2019 compared with 2,625 kbpd in 2018 driven by an increase in supply and continuous capacity optimization;
- higher Flanagan South Pipeline and Seaway Crude Pipeline System throughput period-over-period partially driven by the redirection of throughput to the Gulf Coast resulting from refinery outages;
- higher Bakken Pipeline System throughput period-over-period driven by strong production; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of \$1.33 in 2019 compared with \$1.26 in 2018.

### GAS TRANSMISSION AND MIDSTREAM

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings before interest, income taxes and depreciation and amortization	1,020	126

#### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

EBITDA was positively impacted by \$900 million primarily due to the absence in 2019 of a loss of \$913 million in 2018 on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price.

After taking into consideration the factor above, the remaining \$6 million decrease is primarily explained by the absence in 2019 of earnings from MOLP and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in 2018.

The absence of earnings from assets sold in the prior year was partially offset by:

- contributions from Valley Crossing Pipeline and certain other Offshore assets that were placed into service during 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of \$1.33 in 2019 compared with \$1.26 in 2018.

## GAS DISTRIBUTION

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings before interest, income taxes and depreciation and amortization	662	636

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) were amalgamated on January 1, 2019. The amalgamated company has been renamed Enbridge Gas Inc. (EGI). Post amalgamation the financial results of EGI reflect the combined performance of EGD and Union Gas.

### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

EBITDA was negatively impacted by \$21 million primarily due to employee severance costs of \$35 million in 2019 related to the amalgamation of EGD and Union Gas. This negative factor was partially offset by the absence in 2019 of a negative equity earnings adjustment of \$9 million in 2018 at our equity investee, Noverco Inc., arising from the Tax Cuts and Jobs Act.

After taking into consideration the factors above, the remaining \$47 million increase is primarily explained by the following significant business factors:

- increased earnings of \$38 million period-over-period resulting from colder weather experienced in our franchise service areas when compared to the corresponding period in 2018;
- higher earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base; and
- the absence in 2019 of forecasted earnings sharing which was recorded in 2018 under EGD's previous incentive rate structure.

## RENEWABLE POWER GENERATION AND TRANSMISSION

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings before interest, income taxes and depreciation and amortization	124	109

### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

EBITDA was positively impacted by \$31 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- the absence in 2019 of an asset impairment charge of \$22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- the absence in 2019 of a loss of \$11 million in 2018 representing our share of losses incurred by our equity investee, Rampion Offshore Wind Limited, primarily due to the repair and restoration of damaged power transmission cables, for which we are seeking reimbursement.

After taking into consideration the factors above, the remaining \$16 million decrease is primarily explained by the following significant business factors:

- weaker wind resources at United States wind facilities; and
- the absence in 2019 of \$11 million in 2018 from a positive arbitration settlement related to our Canadian wind facilities.

The negative business factors above were partially offset by the following:

- stronger wind resources at Canadian wind facilities; and
- contributions from the Rampion Offshore Wind Project in 2019 which reached full operating capacity in the second quarter of 2018.

## ENERGY SERVICES

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings before interest, income taxes and depreciation and amortization	6	169

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.

### Three months ended March 31, 2019, compared with the three months ended March 31, 2018

EBITDA decreased by \$317 million primarily due to a non-cash, unrealized loss of \$164 million in 2019 compared with a gain of \$147 million in 2018 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining \$154 million increase is primarily due to increased earnings from Energy Services' crude operations due to the widening of certain location and quality differentials during the second half of 2018, which increased opportunities to generate profitable margins that were realized during the first quarter of 2019.

## ELIMINATIONS AND OTHER

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Earnings/(loss) before interest, income taxes and depreciation and amortization	248	(279)

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements, which are not allocated to business segments. Eliminations and Other also includes the impact of new business development activities and corporate investments.

### **Three months ended March 31, 2019, compared with the three months ended March 31, 2018**

EBITDA was positively impacted by \$445 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$252 million in 2019 compared with a loss of \$136 million in 2018 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk; and
- employee severance, transition and transformation costs of \$9 million in 2019 compared with \$62 million in 2018.

After taking into consideration the factors above, the remaining \$82 million increase is primarily explained by lower operating and administrative costs in the first quarter of 2019 and the timing of the recovery of certain operating and administrative costs allocated to the business segments, which were more heavily weighted to the second half of 2018.

The positive business factor above was partially offset by a realized loss of \$55 million in 2019 compared with a loss of \$42 million in 2018 related to settlements under our foreign exchange risk management program, which partially offset the positive impact of a strengthening United States dollar on our United States business segments.

## GROWTH PROJECTS – COMMERCIALY SECURED PROJECTS

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

	Enbridge's Ownership Interest	Estimated Capital Cost <sup>1</sup>	Expenditures to Date <sup>2</sup>	Status	Expected In-Service Date
<i>(Canadian dollars, unless stated otherwise)</i>					
<b>LIQUIDS PIPELINES</b>					
1. Canadian Line 3 Replacement Program	100%	\$5.3 billion	\$4.4 billion	Under construction	2H - 2020
2. U.S. Line 3 Replacement Program	100%	US\$2.9 billion	US\$1.1 billion	Pre-construction	2H - 2020
3. Gray Oak Pipeline Project	22.8%	US\$0.7 billion	US\$0.3 billion	Under construction	Q4 - 2019
4. Other - United States <sup>3</sup>	100%	US\$0.4 billion	US\$0.4 billion	Substantially complete	2H - 2020
5. Other - Canada <sup>4</sup>	100%	\$0.3 billion	\$0.3 billion	Complete	In service
<b>GAS TRANSMISSION AND MIDSTREAM</b>					
6. Atlantic Bridge	100%	US\$0.6 billion	US\$0.5 billion	Under construction	1H - 2020
7. Spruce Ridge Project	100%	\$0.5 billion	\$0.1 billion	Pre-construction	2H - 2021
8. T-South Expansion Program	100%	\$1.0 billion	\$0.2 billion	Pre-construction	2H - 2021
9. Other - United States	100%	US\$1.1 billion	US\$0.3 billion	Various stages	2019 - 2023
<b>GAS DISTRIBUTION</b>					
10. Dawn-Parkway Expansion	100%	\$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021
<b>RENEWABLE POWER GENERATION AND TRANSMISSION</b>					
11. Hohe See Offshore Wind Project and Expansion	25%	\$1.1 billion (€0.67 billion)	\$0.6 billion (€0.4 billion)	Under construction	2H - 2019
12. Other - Canada	25%	\$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021

<sup>1</sup> 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.

<sup>2</sup> Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to March 31, 2019.

<sup>3</sup> Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.

<sup>4</sup> Athabasca Oil Corporation Lateral Acquisition placed into service in the first quarter of 2019.

A full description of each of our projects is provided in our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 15, 2019. Significant updates that have occurred since the date of filing are discussed below.

### LIQUIDS PIPELINES

- **Gray Oak Pipeline Project** - a crude oil pipeline project connecting West Texas to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 bpd, subject to additional shipper commitments. Project execution forecasts were revised to reflect updated construction cost estimates and timing, with an expected in-service date in the fourth quarter of 2019.

## **GAS TRANSMISSION AND MIDSTREAM**

- **Atlantic Bridge** - expansion of the Algonquin Gas Transmission systems to transport 133 mmcf/d of natural gas to the New England Region. The expansion primarily consists of various meter station additions, the replacement of a natural gas pipeline in Connecticut and Massachusetts, compression additions in Connecticut, and a new compressor station in Massachusetts. The meter stations were placed into service in 2017 and 2018. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The New York portion of the project achieved partial in-service in November 2018 and the revised expected full in-service date is the third quarter of 2019, upon which we will begin earning incremental revenues. The final Massachusetts portion of the project is expected to be in service in the first half of 2020.
- **Spruce Ridge Project**- a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in northern BC. The project will provide additional capacity of up to 402 million cubic feet per day (mmcf/d) with a revised in-service date in the second half of 2021.

## **GAS DISTRIBUTION**

- **Dawn-Parkway Expansion** - the expansion of the existing Dawn to Parkway gas transmission system, which provides transportation service from Dawn to the Greater Toronto Area. The project will provide additional capacity of approximately 75 mmcf/d with an expected in-service date in the second half of 2021.

## **GROWTH PROJECTS - REGULATORY MATTERS**

### **United States Line 3 Replacement Program**

The Minnesota Public Utilities Commission has finalized all of its written orders and has denied all petitions to reconsider its regulatory decisions. The permitting process is under way with all relevant federal and state agencies, and other local government agencies in Minnesota. During the first quarter of 2019, the State of Minnesota provided timelines for issuing their environmental permitting by November 2019. We anticipate that the remaining Federal permits will be finalized approximately 30 to 60 days thereafter.

This new permitting schedule updates our prior expectation for the receipt of final State of Minnesota permits in the second quarter of 2019. In light of this new permitting timeline, we are developing a revised construction schedule and related cost estimates for the U.S. L3R Program, and expect an in-service date during the second half of 2020.

Construction costs for the Line 3 Replacement Program are tracking below budget in Canada and above budget in the United States due to permitting delays in Minnesota. Depending on the final in service date, there is a risk that the project will exceed our total cost estimate of \$9 billion.

## OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

### LIQUIDS PIPELINES

- **Texas COLT Offshore Loading Project** - the Texas COLT Offshore Loading Project will facilitate the direct loading of very large crude carriers from Freeport, Texas. The project consists of a terminal, a 42-inch offshore pipeline, platform and two single point mooring systems with connectivity to all key North American supply basins. During the first quarter of 2019 we acquired the position previously held by Kinder Morgan Inc. We now hold an 80 percent interest in the project and Oiltanking holds the remaining 20 percent interest. The project is expected to be in service by 2022.

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

## 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.

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.

### 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.

## Credit Facilities 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 as at March 31, 2019:

	Maturity Dates	Total Facilities	Draws <sup>1</sup>	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2019-2024	6,137	4,319	1,818
Enbridge (U.S.) Inc.	2021-2024	7,348	5,252	2,096
Enbridge Pipelines Inc.	2020	3,000	1,513	1,487
Enbridge Gas Inc.	2019-2021	2,017	879	1,138
<b>Total committed credit facilities</b>		<b>18,502</b>	<b>11,963</b>	<b>6,539</b>

<sup>1</sup> Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, EGI, EEP and SEP. We also increased existing facilities or obtained new facilities for Enbridge, Enbridge (U.S.) Inc. and EGI to substantially replace the terminated facilities. As a result, our total credit facility availability increased by approximately \$444 million Canadian dollar equivalent.

In addition to the committed credit facilities noted above, we maintain \$800 million of uncommitted demand credit facilities, of which \$516 million were unutilized as at March 31, 2019. As at December 31, 2018, we had \$807 million of uncommitted credit facilities, of which \$548 million were unutilized.

Our net available liquidity of \$7,241 million as at March 31, 2019, was inclusive of \$702 million of unrestricted cash and cash equivalents 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 March 31, 2019, we were in compliance with all debt covenants and we expect to continue to comply with such covenants.

## LONG-TERM DEBT ISSUANCES

During the three months ended March 31, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
<i>(millions of Canadian dollars)</i>			
Enbridge Pipelines Inc.	February 2019	3.52% medium-term notes due February 2029	\$600
	February 2019	4.33% medium-term notes due February 2049	\$600



## LONG-TERM DEBT REPAYMENTS

During the three months ended March 31, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
<i>(millions of Canadian dollars, unless otherwise stated)</i>			
Enbridge Inc.			
Repayment			
	February 2019	4.10% medium-term notes	\$300
Enbridge Energy Partners, L.P.			
Redemption			
	February 2019	8.05% fixed/floating rate junior subordinated notes due 2067	US\$400
Repayment			
	March 2019	9.88% senior notes	US\$500
Westcoast Energy Inc.			
Repayment			
	January 2019	5.60% medium-term notes	\$250
	January 2019	5.60% medium-term notes	\$50

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model support our strong 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. 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 total capital. As at March 31, 2019, our debt capitalization ratio was 47.1%, compared with 46.8% as at December 31, 2018.

There are no material restrictions on our cash. Total restricted cash of \$55 million, as reported on the Consolidated Statements of Financial Position, includes EGI's receipt of cash from the Government of Ontario to fund its Green Investment Fund program. In addition, our restricted cash includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, we had a negative working capital position as at March 31, 2019. The major contributing factor to the negative working capital position was the ongoing funding of 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. As at March 31, 2019 and December 31, 2018, our net available liquidity totaled \$7,241 million and \$9,409 million, respectively.

## SOURCES AND USES OF CASH

	Three months ended March 31,	
	2019	2018
<i>(millions of Canadian dollars)</i>		
Operating activities	2,176	3,194
Investing activities	(2,148)	(2,068)
Financing activities	99	(1,009)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	(7)	19
Increase in cash and cash equivalents and restricted cash	120	136

Significant sources and uses of cash for the three months ended March 31, 2019 and March 31, 2018 are summarized below:

#### **Operating Activities**

- The decrease in cash flow provided by operations during the first quarter of 2019 was primarily driven by changes in operating assets and liabilities. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments generally.
- The factor above was partially offset by stronger contributions from our operating segments and contributions from new assets placed into service as discussed under *Results of Operations*.

#### **Investing Activities**

- The increase in cash used in investing activities during the first quarter 2019 was attributable to activity in 2019 that was not present in 2018, primarily relating to contributions to the Gray Oak Holdings LLC equity investment starting in January 2019.
- We are continuing with the execution of our growth 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.

#### **Financing Activities**

- The decrease in cash used in financing activities during the first quarter of 2019 was primarily attributable to a net increase in commercial paper and credit facility draws, partially offset by higher repayments of maturing long-term debt and a decrease of long-term debt issued in 2019 when compared to the same period in 2018.
- Our common share dividend payments increased quarter-over-quarter primarily due to the increase in the common share dividend rate and an increase in the number of common shares outstanding in connection with the buy-in of our sponsored vehicles in the fourth quarter of 2018. These factors were partially offset by the suspension of our Dividend Reinvestment and Share Purchase Plan in the fourth quarter of 2018. In addition, in March 2019, Westcoast Energy Inc. redeemed all of its outstanding Series 7 and Series 8 preference shares for a total payment of \$300 million.
- Distributions to noncontrolling interests and redeemable noncontrolling interests decreased as a result of the buy-in of our sponsored vehicles in the fourth quarter 2018.

## **LEGAL AND OTHER UPDATES**

### **LIQUIDS PIPELINES**

#### **Eddystone Rail Legal Matter**

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania (the Court). Eddystone Rail alleges that the defendants transferred valuable assets from Eddystone Rail's counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone Rail. Eddystone Rail is seeking payment of compensatory and punitive damages in excess of US\$140 million. On July 19, 2017, the defendants' initial motions to dismiss Eddystone Rail's claims were denied. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US\$32 million. Eddystone Rail filed a motion to dismiss the counterclaims and defendants amended their Answer and Counterclaims on September 21, 2017. On October 12, 2017 Eddystone Rail moved to dismiss the latest version of defendants' counterclaims. On February 6, 2018, the Court denied without prejudice Eddystone Rail's motion to dismiss the defendants' counterclaims. The defendants' chances of success on their counterclaims cannot be predicted at this time. On September 7, 2018, the Court granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants. Motions to dismiss Eddystone Rail's amended complaint were subsequently denied by the Court. On January 25, 2019, defendants moved to dismiss Eddystone Rail's claims from the Court based on lack of subject matter jurisdiction, which motion was denied by the Court on March 26, 2019.

#### **Dakota Access Pipeline**

In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the Court contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline (DAPL). The plaintiffs requested the Court order the operator to shut down the pipeline until the appropriate regulatory process is completed. The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corp permit and environmental review process.

On June 14, 2017, the Court ruled that the Army Corps did not sufficiently weigh the degree to which the project's effects would be highly controversial and the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Tribes and on environmental justice (the June 2017 Order). The Court ordered the Army Corps to reconsider those components of its environmental analysis. On October 11, 2017, the Court issued an order that allows DAPL to continue operating while the Army Corps completes the additional environmental review required by the June 2017 Order. The Court additionally ordered DAPL to implement certain interim measures pending the Army Corps' supplemental analysis. The Army Corps issued its decision on August 31, 2018, and found that no supplemental environmental analysis is required. All four Tribes amended their complaints to include claims challenging the adequacy of the Army Corps' supplemental environmental analysis.

On February 4, 2019, the Army Corps produced its administrative record, which includes all documents pertaining to its remand process. On February 27, 2019, a plaintiff filed a motion challenging the completeness of the Army Corps' administrative record, arguing that relevant documents had been improperly excluded. The Army Corps and DAPL opposed that motion on March 11, 2019, and the plaintiff filed a reply brief on March 18, 2019. Briefing on the administrative record challenge is now complete and a decision by the court is pending. A schedule for filing summary judgment briefs on the merits of the plaintiff Tribes' remaining claims will be established following resolution of the administrative record challenge.

### **Line 5 Dual Pipelines**

In December 2018, Michigan law PA 359 was enacted which created the Mackinac Straits Corridor Authority (Corridor Authority) and authorized an agreement between us and the Corridor Authority for the construction of a tunnel under the Straits of Mackinac (Straits) to house a replacement for the Line 5 Dual Pipelines that currently cross the Straits. On December 19, 2018, we entered into a tunnel project agreement with the Government of Michigan under the administration of former Governor Snyder. On March 28, 2019, the new Michigan Attorney General issued an opinion finding the Michigan law PA 359 unconstitutional. Immediately following the Attorney General's opinion that the Michigan law was unconstitutional, the new Michigan Governor Whitmer issued a directive to Michigan agencies to cease any action implementing the statute. We are currently in discussions with Governor Whitmer's office about how to collaboratively advance the tunnel project.

### **OTHER LITIGATION**

We and our subsidiaries are involved in 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 by special interest groups. 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.

### **CAPITAL EXPENDITURE COMMITMENTS**

We have signed contracts for the purchase of services, pipe and other materials totaling approximately \$2.1 billion which are expected to be paid over the next five years.

### **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.

### **CHANGES IN ACCOUNTING POLICIES**

Refer to Item 1. *Financial Statements - Note 2. Changes in Accounting Policies.*

## **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Our exposure to market risk is described in Part II. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of our Annual Report on Form 10-K for the year ended December 31, 2018, as filed with the SEC on February 15, 2019. We believe our exposure to market risk has not changed materially since then.

## **ITEM 4. CONTROLS AND PROCEDURES**

### **Evaluation of Disclosure Controls and Procedures**

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as at March 31, 2019, and based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

#### **Changes in Internal Control over Financial Reporting**

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended March 31, 2019 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

## **PART II - OTHER INFORMATION**

### **ITEM 1. LEGAL PROCEEDINGS**

We are involved in various legal and regulatory actions and proceedings which arise in the ordinary course of business. 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. Refer to Part I. Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of other legal proceedings.

### **ITEM 1A. RISK FACTORS**

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I. Item 1A. *Risk Factors* of our Annual Report on Form 10-K for the year ended December 31, 2018, which could materially affect our financial condition or future results. There have been no material modifications to those risk factors.

### **ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**

None.

### **ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

None.

### **ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

## ITEM 5. OTHER INFORMATION

The information set forth in this Item 5 is included herein for the purpose of providing the disclosure required under Item 5.02(b), (c) and (e) of Form 8-K.

On May 8, 2019, the Board of Directors (the Board) of Enbridge Inc. (Enbridge) appointed Colin K. Gruending as Executive Vice President & Chief Financial Officer and Mark A. Maki as Senior Vice President & Chief Accounting Officer, with each such appointment effective as of June 1, 2019 (the Effective Date).

Mr. Gruending will succeed John K. Whelen, Enbridge's current Executive Vice President & Chief Financial Officer who, as of the Effective Date, will become Enbridge's Executive Vice President & Chief Development Officer. As of the Effective Date, Mr. Maki will succeed Allen C. Capps, Enbridge's current Senior Vice President & Chief Accounting Officer who will become Enbridge's Senior Vice President, Corporate Development & Investment Review.

Mr. Gruending, 49, previously served as Senior Vice President, Corporate Development & Investment Review from 2018 to 2019, as Vice President, Corporate Development & Investment Review from 2017 to 2018, as Vice President, Corporate Development from 2016 to 2017 and as Vice President, Corporate Development & Planning from 2014 to 2016. Prior to that, Mr. Gruending served as Vice President, Treasury & Tax from 2011 to 2014 and as Vice President & Controller from 2005 to 2011. There is no arrangement or understanding between Mr. Gruending and any other person pursuant to which he was appointed and there are no family relationships between Mr. Gruending and any director or executive officer of Enbridge. Mr. Gruending has no direct or indirect material interest in any transaction required to be disclosed pursuant to Item 404(a) of Regulation S-K.

Mr. Maki, 54, previously served as Senior Vice President, Corporate Planning & Sponsored Vehicles from 2018 to 2019, as Senior Vice President, Finance Business Partners from 2017 to 2018 and as Senior Vice President, Finance from 2016 to 2017. Mr. Maki has also served as President & Principal Executive Officer of Enbridge Energy Management, L.L.C. and the General Partner, Enbridge Energy Company, Inc., since 2014. He served as President of Enbridge Energy Management, L.L.C. and as Senior Vice President of the General Partner from 2010 to 2014. There is no arrangement or understanding between Mr. Maki and any other person pursuant to which he was appointed and there are no family relationships between Mr. Maki and any director or executive officer of Enbridge. Mr. Maki has no direct or indirect material interest in any transaction required to be disclosed pursuant to Item 404(a) of Regulation S-K.

In connection with his appointment, starting on the Effective Date, Mr. Gruending will receive a base salary of C\$525,000 and will be eligible to earn an annual discretionary bonus under Enbridge's Short Term Incentive Plan, with a target of 80% of his base salary. On the Effective Date, Mr. Gruending will be granted performance stock units with grant value of C\$656,000 under Enbridge's 2019 Long-Term Incentive Plan (the 2019 LTIP) in respect of an increase to his 2019 long-term incentive target. These performance stock units will be subject to the terms and conditions of the form of award agreement set forth in Exhibit 10.5 to this Form 10-Q, which information is incorporated herein by reference.

On May 8, 2019, the Board also awarded William T. Yardley, Executive Vice President & President, Gas Transmission & Midstream restricted stock units under the 2019 LTIP having a grant value of US\$1.5 million. The restricted stock units will vest as to 20% of the award on each of the first and second anniversaries of grant, with the remainder of such award vesting on the third anniversary of grant, in each case, subject to Mr. Yardley's continued employment with Enbridge.

## ITEM 6. EXHIBITS

Each exhibit identified below is included as a part of this quarterly report. Exhibits included in this filing are designated by an asterisk (“\*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated.

<b>Exhibit No.</b>	<b>Description</b>
<a href="#"><u>2.1</u></a>	<a href="#"><u>Agreement and Plan of Merger, dated as of September 5, 2016, by and among Spectra Energy Corp, Enbridge Inc. and Sand Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Enbridge’s Registration Statement on Form F-4 filed September 23, 2017)</u></a>
<a href="#"><u>2.2</u></a>	<a href="#"><u>Agreement and Plan of Merger, dated as of August 24, 2018, by and among Spectra Energy Partners, LP, Spectra Energy Partners (DE) GP, LP, Enbridge Inc., Enbridge (U.S.) Inc., Autumn Acquisition Sub, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc., Spectra Energy Corp, Spectra Energy Capital, LLC and Spectra Energy Transmission, LLC. (incorporated by reference to Exhibit 2.1 to Enbridge’s Form 8-K filed August 24, 2018)</u></a>
<a href="#"><u>2.3</u></a>	<a href="#"><u>Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Partners, L.P., Enbridge Energy Company, Inc., Enbridge Energy Management, L.L.C., Enbridge Inc., Enbridge (U.S.) Inc., Winter Acquisition Sub II, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc. (incorporated by reference to Exhibit 2.1 to Enbridge’s Form 8-K filed September 18, 2018)</u></a>
<a href="#"><u>2.4</u></a>	<a href="#"><u>Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Management, L.L.C., Enbridge Inc., Winter Acquisition Sub I, Inc., and solely for the purposes of Article I, Section 2.4 and Article X, Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 2.2 to Enbridge’s Form 8-K filed September 18, 2018)</u></a>
<a href="#"><u>2.5</u></a>	<a href="#"><u>Arrangement Agreement, dated as of September 17, 2018, by and between Enbridge Inc. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 2.3 to Enbridge’s Form 8-K filed September 18, 2018)</u></a>
<a href="#"><u>10.1*</u></a>	<a href="#"><u>Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019)</u></a>
<a href="#"><u>10.2*</u></a>	<a href="#"><u>Enbridge Inc. Directors’ Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019</u></a>
<a href="#"><u>10.3</u></a>	<a href="#"><u>Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge’s Proxy Statement on Schedule 14A for Enbridge’s Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019)</u></a>
<a href="#"><u>10.4*</u></a>	<a href="#"><u>Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement</u></a>
<a href="#"><u>10.5*</u></a>	<a href="#"><u>Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement</u></a>
<a href="#"><u>10.6*</u></a>	<a href="#"><u>Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement</u></a>
<a href="#"><u>10.7*</u></a>	<a href="#"><u>Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement</u></a>
<a href="#"><u>31.1*</u></a>	<a href="#"><u>Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u></a>
<a href="#"><u>31.2*</u></a>	<a href="#"><u>Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</u></a>

<a href="#"><u>32.1*</u></a>	<a href="#"><u>Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u></a>
<a href="#"><u>32.2*</u></a>	<a href="#"><u>Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</u></a>
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.



## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

### ENBRIDGE INC.

(Registrant)

Date: May 10, 2019

By: /s/ Al Monaco

Al Monaco  
President and Chief Executive Officer

Date: May 10, 2019

By: /s/ John K. Whelen

John K. Whelen  
Executive Vice President and Chief Financial  
Officer  
(Principal Financial Officer)



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