Third Quarter

Interim Report to Shareholders
For the nine months ended September 30, 2019

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 September 30, 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	**98-0377957**
(State or Other Jurisdiction of Incorporation or Organization)	(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	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange
6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078	ENBA	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 2,023,924,736 common shares outstanding as at November 1, 2019.

GLOSSARY

AOCI	Accumulated other comprehensive income/(loss)
Army Corps	United States Army Corps of Engineers
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CER	The Canadian Regulator Act created the new Canada Energy Regulator and repealed the National Energy Board Act, on August 28, 2019
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
Enbridge	Enbridge Inc.
Merger Transaction	Combination of Enbridge and Spectra Energy through a stock-for-stock merger transaction which closed on February 27, 2017
MNPUC	Minnesota Public Utilities Commission
MOLP	Midcoast Operating, L.P. and its subsidiaries
NGL	Natural gas liquids
OCI	Other comprehensive income/(loss)
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 and related court proceedings; 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); the expected in-service date of the Canadian Line 3 Replacement Program (Canadian L3R Program); Line 5 related matters; Mainline System contracting; 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 September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**7,396**	6,919	**22,444**	20,638
Gas distribution sales	**454**	478	**3,085**	3,260
Transportation and other services	**3,748**	3,948	**12,188**	10,918
Total operating revenues *(Note 3)*	**11,598**	11,345	**37,717**	34,816
Operating expenses				
Commodity costs	**7,216**	6,905	**21,910**	20,180
Gas distribution costs	**104**	112	**1,623**	1,857
Operating and administrative	**1,741**	1,652	**5,061**	4,929
Depreciation and amortization	**844**	799	**2,526**	2,452
Impairment of long-lived assets	**105**	4	**105**	1,076
Impairment of goodwill	**—**	1,019	**—**	1,019
Total operating expenses	**10,010**	10,491	**31,225**	31,513
Operating income	**1,588**	854	**6,492**	3,303
Income from equity investments	**333**	378	**1,159**	1,076
Other income/(expense)				
Net foreign currency (loss)/gain	**(43)**	57	**311**	(171)
Other	**81**	(33)	**192**	61
Interest expense	**(644)**	(696)	**(1,966)**	(2,042)
Earnings before income taxes	**1,315**	560	**6,188**	2,227
Income tax expense *(Note 12)*	**(255)**	(347)	**(1,275)**	(177)
Earnings	**1,060**	213	**4,913**	2,050
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(15)**	(209)	**(50)**	(352)
Earnings attributable to controlling interests	**1,045**	4	**4,863**	1,698
Preference share dividends	**(96)**	(94)	**(287)**	(272)
Earnings/(loss) attributable to common shareholders	**949**	(90)	**4,576**	1,426
Earnings/(loss) per common share attributable to common shareholders *(Note 5)*	**0.47**	(0.05)	**2.27**	0.84
Diluted earnings/(loss) per common share attributable to common shareholders *(Note 5)*	**0.47**	(0.05)	**2.27**	0.84

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars)				
Earnings	**1,060**	213	**4,913**	2,050
Other comprehensive income/(loss), net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**(170)**	57	**(597)**	150
Change in unrealized gain/(loss) on net investment hedges	**(74)**	83	**147**	(200)
Other comprehensive income from equity investees	**2**	(1)	**19**	18
Reclassification to earnings of loss on cash flow hedges	**28**	31	**74**	104
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**1**	5	**44**	28
Foreign currency translation adjustments	**704**	(989)	**(1,898)**	1,637
Other comprehensive income/(loss), net of tax	**491**	(814)	**(2,211)**	1,737
Comprehensive income/(loss)	**1,551**	(601)	**2,702**	3,787
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(41)**	(102)	**23**	(546)
Comprehensive income/(loss) attributable to controlling interests	**1,510**	(703)	**2,725**	3,241
Preference share dividends	**(96)**	(94)	**(287)**	(272)
Comprehensive income/(loss) attributable to common shareholders	**1,414**	(797)	**2,438**	2,969

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars, except per share amounts)				
Preference shares *(Note 5)*				
Balance at beginning and end of period	**7,747**	7,747	**7,747**	7,747
Common shares *(Note 5)*				
Balance at beginning of period	**64,732**	51,548	**64,677**	50,737
Dividend Reinvestment and Share Purchase Plan	**—**	391	**—**	1,181
Shares issued on exercise of stock options	**3**	5	**58**	26
Balance at end of period	**64,735**	51,944	**64,735**	51,944
Additional paid-in capital				
Balance at beginning of period	**194**	4,311	**—**	3,194
Stock-based compensation	**7**	6	**28**	40
Options exercised	**(2)**	(4)	**(51)**	(14)
Dilution gain on Spectra Energy Partners, LP restructuring	**—**	—	**—**	1,136
Change in reciprocal interest	**—**	—	**109**	—
Repurchase of noncontrolling interest	**—**	—	**65**	—
Sale of noncontrolling interests in subsidiaries	**—**	79	**—**	79
Other	**7**	(46)	**55**	(89)
Balance at end of period	**206**	4,346	**206**	4,346
Deficit				
Balance at beginning of period	**(3,392)**	(2,649)	**(5,538)**	(2,468)
Earnings attributable to controlling interests	**1,045**	4	**4,863**	1,698
Preference share dividends	**(96)**	(94)	**(287)**	(272)
Dividends paid to reciprocal shareholder	**5**	8	**14**	25
Common share dividends declared	**(1,493)**	(1,152)	**(2,993)**	(2,297)
Modified retrospective adoption of *ASC 606 Revenue from Contracts with Customers*	**—**	—	**—**	(86)
Redemption value adjustment attributable to redeemable noncontrolling interests	**—**	165	**—**	(318)
Other	**(1)**	—	**9**	—
Balance at end of period	**(3,932)**	(3,718)	**(3,932)**	(3,718)
Accumulated other comprehensive income/(loss) *(Note 9)*				
Balance at beginning of period	**124**	1,277	**2,672**	(973)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**465**	(707)	**(2,138)**	1,543
Other	**(7)**	—	**48**	—
Balance at end of period	**582**	570	**582**	570
Reciprocal shareholding				
Balance at beginning of period	**(51)**	(102)	**(88)**	(102)
Change in reciprocal interest	**—**	—	**37**	—
Balance at end of period	**(51)**	(102)	**(51)**	(102)
Total Enbridge Inc. shareholders' equity	**69,287**	60,787	**69,287**	60,787
Noncontrolling interests				
Balance at beginning of period	**3,451**	6,100	**3,965**	7,597
Earnings attributable to noncontrolling interests	**15**	119	**50**	248
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**(1)**	2	**(6)**	8
Foreign currency translation adjustments	**27**	(89)	**(67)**	140
Reclassification to earnings of loss on cash flow hedges	**—**	8	**—**	23
	26	(79)	**(73)**	171
Comprehensive income/(loss) attributable to noncontrolling interests	**41**	40	**(23)**	419
Spectra Energy Partners, LP restructuring	**—**	—	**—**	(1,486)
Contributions	**1**	2	**10**	23
Distributions	**(94)**	(212)	**(194)**	(637)
Sale of noncontrolling interests in subsidiaries	**—**	1,183	**—**	1,183
Repurchase of noncontrolling interest	**—**	—	**(65)**	—
Redemption of preferred shares held by subsidiary *(Note 10)*	**—**	—	**(300)**	—
Other	**(10)**	(2)	**(4)**	12
Balance at end of period	**3,389**	7,111	**3,389**	7,111
Total equity	**72,676**	67,898	**72,676**	67,898
Dividends paid per common share	**0.738**	0.671	**2.214**	2.013
Earnings per common share attributable to common shareholders *(Note 5)*	**0.47**	(0.05)	**2.27**	0.84
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.47**	(0.05)	**2.27**	0.84

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30,	
	2019	2018
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**4,913**	2,050
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**2,526**	2,452
Deferred income tax (recovery)/expense	**983**	(51)
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 11)*	**(1,005)**	319
Earnings from equity investments	**(1,159)**	(1,076)
Distributions from equity investments	**1,442**	1,090
Impairment of long-lived assets	**105**	1,076
Impairment of goodwill	**—**	1,019
Loss on dispositions	**—**	76
Other	**51**	101
Changes in operating assets and liabilities	**(451)**	943
Net cash provided by operating activities	**7,405**	7,999
Investing activities		
Capital expenditures	**(3,928)**	(4,584)
Long-term investments and restricted long-term investments	**(1,018)**	(1,091)
Distributions from equity investments in excess of cumulative earnings	**285**	1,243
Additions to intangible assets	**(136)**	(491)
Proceeds from dispositions	**—**	1,913
Other	**—**	(12)
Affiliate loans, net	**(232)**	(50)
Net cash used in investing activities	**(5,029)**	(3,072)
Financing activities		
Net change in short-term borrowings	**245**	(196)
Net change in commercial paper and credit facility draws	**3,365**	(2,358)
Debenture and term note issues, net of issue costs	**2,553**	3,537
Debenture and term note repayments	**(2,994)**	(3,757)
Sale of noncontrolling interests in subsidiaries	**—**	1,289
Contributions from noncontrolling interests	**10**	23
Distributions to noncontrolling interests	**(194)**	(637)
Contributions from redeemable noncontrolling interests	**—**	62
Distributions to redeemable noncontrolling interests	**—**	(264)
Common shares issued	**18**	17
Preference share dividends	**(287)**	(268)
Common share dividends	**(4,480)**	(2,254)
Redemption of preferred shares held by subsidiary *(Note 10)*	**(300)**	—
Other	**(60)**	(5)
Net cash used in financing activities	**(2,124)**	(4,811)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(17)**	23
Net increase in cash and cash equivalents and restricted cash	**235**	139
Cash and cash equivalents and restricted cash at beginning of period	**637**	587
Cash and cash equivalents and restricted cash at end of period	**872**	726

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2019	December 31, 2018
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**815**	518
Restricted cash	**57**	119
Accounts receivable and other	**5,833**	6,517
Accounts receivable from affiliates	**89**	79
Inventory	**1,261**	1,339
	8,055	8,572
Property, plant and equipment, net	**94,379**	94,540
Long-term investments	**16,831**	16,707
Restricted long-term investments	**413**	323
Deferred amounts and other assets	**9,866**	8,558
Intangible assets, net	**2,216**	2,372
Goodwill	**33,668**	34,459
Deferred income taxes	**1,213**	1,374
Total assets	**166,641**	166,905
Liabilities and equity		
Current liabilities		
Short-term borrowings	**1,269**	1,024
Accounts payable and other	**7,130**	9,863
Accounts payable to affiliates	**47**	40
Interest payable	**566**	669
Current portion of long-term debt	**4,536**	3,259
	13,548	14,855
Long-term debt	**60,879**	60,327
Other long-term liabilities	**9,433**	8,834
Deferred income taxes	**10,105**	9,454
	93,965	93,470
Contingencies *(Note 15)*		
Equity		
Share capital		
Preference shares	**7,747**	7,747
Common shares *(2,024 and 2,022 outstanding at September 30, 2019 and December 31, 2018, respectively)*	**64,735**	64,677
Additional paid-in capital	**206**	—
Deficit	**(3,932)**	(5,538)
Accumulated other comprehensive income *(Note 9)*	**582**	2,672
Reciprocal shareholding	**(51)**	(88)
Total Enbridge Inc. shareholders' equity	**69,287**	69,470
Noncontrolling interests	**3,389**	3,965
	72,676	73,435
Total liabilities and equity	**166,641**	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. 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 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.

Improvements to Related Party Guidance for Variable Interest Entities
Effective September 30, 2019 we adopted ASU 2018-17 on a retrospective basis. The new standard was issued with the objective 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 decision maker fees constitute a variable interest. The adoption of this ASU did not have a material impact on our consolidated financial statements.

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. The adoption of ASU 2018-18 is not expected to have a material impact on the Company's 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 September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	**2,305**	**1,073**	**135**	**—**	**—**	**—**	**3,513**
Storage and other revenues	**31**	**69**	**48**	**—**	**—**	**—**	**148**
Gas gathering and processing revenues	**—**	**98**	**—**	**—**	**—**	**—**	**98**
Gas distribution revenue	**—**	**—**	**470**	**—**	**—**	**—**	**470**
Electricity and transmission revenues	**—**	**—**	**—**	**46**	**—**	**—**	**46**
Total revenue from contracts with customers	**2,336**	**1,240**	**653**	**46**	**—**	**—**	**4,275**
Commodity sales	**—**	**—**	**—**	**—**	**7,396**	**—**	**7,396**
Other revenues[1,2]	**(156)**	**23**	**(21)**	**82**	**(1)**	**—**	**(73)**
Intersegment revenues	**88**	**1**	**3**	**—**	**8**	**(100)**	**—**
Total revenues	**2,268**	**1,264**	**635**	**128**	**7,403**	**(100)**	**11,598**

Three months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	2,190	979	97	—	—	—	3,266
Storage and other revenues	31	53	55	—	—	—	139
Gas gathering and processing revenues	—	200	—	—	—	—	200
Gas distribution revenues	—	—	478	—	—	—	478
Electricity and transmission revenues	—	—	—	43	—	—	43
Commodity sales	—	298	—	—	—	—	298
Total revenue from contracts with customers	2,221	1,530	630	43	—	—	4,424
Commodity sales	—	—	—	—	6,621	—	6,621
Other revenues[1, 2]	222	(6)	11	74	—	(1)	300
Intersegment revenues	86	4	4	—	25	(119)	—
Total revenues	2,529	1,528	645	117	6,646	(120)	11,345

Nine months ended September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	**6,749**	**3,323**	**555**	**—**	**—**	**—**	**10,627**
Storage and other revenues	**83**	**168**	**154**	**—**	**—**	**—**	**405**
Gas gathering and processing revenues	**—**	**329**	**—**	**—**	**—**	**—**	**329**
Gas distribution revenue	**—**	**—**	**3,080**	**—**	**—**	**—**	**3,080**
Electricity and transmission revenues	**—**	**—**	**—**	**139**	**—**	**—**	**139**
Commodity sales	**—**	**3**	**—**	**—**	**—**	**—**	**3**
Total revenue from contracts with customers	**6,832**	**3,823**	**3,789**	**139**	**—**	**—**	**14,583**
Commodity sales	**—**	**—**	**—**	**—**	**22,441**	**—**	**22,441**
Other revenues[1,2]	**383**	**43**	**5**	**278**	**(2)**	**(14)**	**693**
Intersegment revenues	**280**	**4**	**9**	**—**	**55**	**(348)**	**—**
Total revenues	**7,495**	**3,870**	**3,803**	**417**	**22,494**	**(362)**	**37,717**

Nine months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	6,327	2,889	487	—	—	—	9,703
Storage and other revenues	113	164	173	—	—	—	450
Gas gathering and processing revenues	—	636	—	—	—	—	636
Gas distribution revenues	—	—	3,260	—	—	—	3,260
Electricity and transmission revenues	—	—	—	153	—	—	153
Commodity sales	—	1,630	—	—	—	—	1,630
Total revenue from contracts with customers	6,440	5,319	3,920	153	—	—	15,832
Commodity sales	—	—	—	—	19,008	—	19,008
Other revenues[1, 2]	(308)	2	22	270	—	(10)	(24)
Intersegment revenues	256	8	10	—	106	(380)	—
Total revenues	6,388	5,329	3,952	423	19,114	(390)	34,816

1 Includes mark-to-market gains/(losses) from our hedging program.
2 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
(millions of Canadian dollars)			
Balance as at December 31, 2018	**1,929**	**191**	**1,297**
Balance as at September 30, 2019	**1,694**	**191**	**1,437**

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. Revenue recognized during the three and nine months ended September 30, 2019 included in contract liabilities at the beginning of the period was $19 million and $149 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenues during the three and nine months ended September 30, 2019 were $171 million and $314 million, respectively.

Performance Obligations

There were no material revenues recognized in the three and nine months ended September 30, 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 $64.7 billion, of which $1.8 billion and $6.0 billion is expected to be recognized during the three 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 revenue 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, revenue 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

Three months ended September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	**—**	**—**	**17**	**—**	**—**	**17**
Revenues from products and services transferred over time[2]	**2,336**	**1,240**	**636**	**46**	**—**	**4,258**
Total revenue from contracts with customers	**2,336**	**1,240**	**653**	**46**	**—**	**4,275**

Three months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	—	298	20	—	—	318
Revenues from products and services transferred over time[2]	2,221	1,232	610	43	—	4,106
Total revenue from contracts with customers	2,221	1,530	630	43	—	4,424

Nine months ended September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	**—**	**3**	**51**	**—**	**—**	**54**
Revenues from products and services transferred over time[2]	**6,832**	**3,820**	**3,738**	**139**	**—**	**14,529**
Total revenue from contracts with customers	**6,832**	**3,823**	**3,789**	**139**	**—**	**14,583**

Nine months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	—	1,630	65	—	—	1,695
Revenues from products and services transferred over time[2]	6,440	3,689	3,855	153	—	14,137
Total revenue from contracts with customers	6,440	5,319	3,920	153	—	15,832

1 *Revenues from sales of crude oil, natural gas and NGLs.*
2 *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

Three months ended September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,268**	**1,264**	**635**	**128**	**7,403**	**(100)**	**11,598**
Commodity and gas distribution costs	**(12)**	**—**	**(132)**	**—**	**(7,287)**	**111**	**(7,320)**
Operating and administrative	**(815)**	**(550)**	**(267)**	**(55)**	**(19)**	**(35)**	**(1,741)**
Impairment of long-lived assets	**—**	**(105)**	**—**	**—**	**—**	**—**	**(105)**
Income/(loss) from equity investments	**205**	**135**	**(11)**	**5**	**—**	**(1)**	**333**
Other income/(expense)	**—**	**28**	**27**	**4**	**(6)**	**(15)**	**38**
Earnings before interest, income taxes, and depreciation and amortization	**1,646**	**772**	**252**	**82**	**91**	**(40)**	**2,803**
Depreciation and amortization							**(844)**
Interest expense							**(644)**
Income tax expense							**(255)**
Earnings							**1,060**
Capital expenditures[1]	**442**	**436**	**247**	**2**	**—**	**32**	**1,159**

Three months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	2,529	1,528	645	117	6,646	(120)	11,345
Commodity and gas distribution costs	(5)	(270)	(137)	—	(6,726)	121	(7,017)
Operating and administrative	(790)	(519)	(263)	(38)	(17)	(25)	(1,652)
Impairment of long-lived assets	—	—	—	(4)	—	—	(4)
Impairment of goodwill	—	(1,019)	—	—	—	—	(1,019)
Income/(loss) from equity investments	131	262	(12)	(6)	3	—	378
Other (expense)/income	10	(42)	23	(18)	(2)	53	24
Earnings/(loss) before interest, income taxes, and depreciation and amortization	1,875	(60)	256	51	(96)	29	2,055
Depreciation and amortization							(799)
Interest expense							(696)
Income tax expense							(347)
Earnings							213
Capital expenditures[1]	651	413	311	6	—	(19)	1,362

Nine months ended September 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**7,495**	**3,870**	**3,803**	**417**	**22,494**	**(362)**	**37,717**
Commodity and gas distribution costs	**(25)**	**—**	**(1,740)**	**(2)**	**(22,125)**	**359**	**(23,533)**
Operating and administrative	**(2,392)**	**(1,626)**	**(829)**	**(137)**	**(53)**	**(24)**	**(5,061)**
Impairment of long-lived assets	**—**	**(105)**	**—**	**—**	**—**	**—**	**(105)**
Income from equity investments	**606**	**525**	**2**	**23**	**3**	**—**	**1,159**
Other income/(expense)	**26**	**69**	**68**	**(1)**	**(1)**	**342**	**503**
Earnings before interest, income taxes, and depreciation and amortization	**5,710**	**2,733**	**1,304**	**300**	**318**	**315**	**10,680**
Depreciation and amortization							**(2,526)**
Interest expense							**(1,966)**
Income tax expense							**(1,275)**
Earnings							**4,913**
Capital expenditures[1]	**1,984**	**1,254**	**643**	**18**	**2**	**71**	**3,972**

Nine months ended September 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	6,388	5,329	3,952	423	19,114	(390)	34,816
Commodity and gas distribution costs	(14)	(1,481)	(1,969)	—	(18,965)	392	(22,037)
Operating and administrative	(2,251)	(1,560)	(782)	(104)	(50)	(182)	(4,929)
Impairment of long-lived assets	(154)	(913)	—	(4)	—	(5)	(1,076)
Impairment of goodwill	—	(1,019)	—	—	—	—	(1,019)
Income/(loss) from equity investments	399	699	(5)	(27)	10	—	1,076
Other (expense)/income	(15)	25	66	(2)	(1)	(183)	(110)
Earnings/(loss) before interest, income taxes, and depreciation and amortization	4,353	1,080	1,262	286	108	(368)	6,721
Depreciation and amortization							(2,452)
Interest expense							(2,042)
Income tax expense							(177)
Earnings							2,050
Capital expenditures[1]	1,776	2,105	733	30	—	(11)	4,633

1 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 and nine months ended September 30, 2019 and 2018, respectively, 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 September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(number of common shares in millions)				
Weighted average shares outstanding	**2,018**	1,705	**2,017**	1,695
Effect of dilutive options	**2**	3	**3**	4
Diluted weighted average shares outstanding	**2,020**	1,708	**2,020**	1,699

For the three months ended September 30, 2019 and 2018, 21.9 million and 21.1 million, respectively, anti-dilutive stock options with a weighted average exercise price of $52.75 and $52.17, respectively, were excluded from the diluted earnings per common share calculation.

For the nine months ended September 30, 2019 and 2018, 17.9 million and 27.1 million, respectively, anti-dilutive stock options with a weighted average exercise price of $53.48 and $50.37, respectively, were excluded from the diluted earnings per common share calculation.

DIVIDENDS PER SHARE

On November 5, 2019, our Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2019, to shareholders of record on November 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[1]	$0.25243
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[2]	$0.27369
Preference Shares, Series R[3]	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3[4]	$0.23356
Preference Shares, Series 5[5]	US$0.33596
Preference Shares, Series 7[6]	$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, was increased to $0.25647 from $0.25395 on June 1, 2019 and was decreased to $0.25243 from $0.25647 on September 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 R was increased to $0.25456 from $0.25000 on June 1, 2019, due to the reset of the annual dividend on June 1, 2019, and every five years thereafter.

4 The quarterly dividend per share paid on Series 3 was decreased to $0.23356 from $0.25000 on September 1, 2019, due to the reset of the annual dividend on September 1, 2019, and every five year thereafter.

5 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.

6 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 nine months ended September 30, 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. We closed the sale of EGNB on October 1, 2019. Please refer to *Note 17. Subsequent Events*.

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. The assets of our Canadian natural gas gathering and processing businesses are included in our Gas Transmission and Midstream segment. 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 by the end of 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, and its related assets, which are included in our Liquids Pipelines segment. 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 by the end of 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. (St. Lawrence Gas), whose assets are included in the Gas Distribution segment. The cash proceeds for the transaction are $72 million (US$55 million), subject to customary closing adjustments. The sale was approved by the New York State Public Service Commission on October 17, 2019 and it closed on November 1, 2019. Please refer to *Note 17. Subsequent Events*.

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

	September 30, 2019	December 31, 2018
(millions of Canadian dollars)		
Accounts receivable and other (current assets held for sale)	**72**	117
Deferred amounts and other assets (long-term assets held for sale)[1]	**2,473**	2,383
Accounts payable and other (current liabilities held for sale)	**(47)**	(63)
Other long-term liabilities (long-term liabilities held for sale)	**(90)**	(96)
Net assets held for sale	**2,408**	2,341

1 Included within Deferred amounts and other assets at September 30, 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 September 30, 2019 and December 31, 2018, the carrying amount of the investment in Gray Oak Holdings was $466 million and nil, respectively. Enbridge's maximum exposure to loss as at September 30, 2019 was approximately $955 million and primarily consists of our portion of the project construction costs.

On June 4, 2019, the partners of Gray Oak executed a term loan facility with a syndicate of banks with a borrowing capacity of US$1,230 million to finance the construction of the Gray Oak crude oil pipeline. An Equity Contribution Agreement was executed by the partners of Gray Oak Holdings to backstop the term loan facility until certain release conditions are met. On July 2, 2019, the partners exercised an option on the term loan facility for an additional US$87 million, bringing the total borrowing capacity under the facility to US$1,317 million.

At September 30, 2019 Gray Oak had US$904 million outstanding on the term loan facility, and the guarantee associated with our effective interest was US$206 million. The maximum amount committed by Enbridge under the Equity Contribution Agreement is US$300 million, which is proportionate to our effective ownership interest.

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 September 30, 2019:

	Maturity	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2021-2024	**7,024**	**6,400**	**624**
Enbridge (U.S.) Inc.	2021-2024	**7,282**	**2,680**	**4,602**
Enbridge Pipelines Inc.	2021	**3,000**	**2,555**	**445**
Enbridge Gas Inc.	2019-2021	**2,017**	**1,280**	**737**
Total committed credit facilities		**19,323**	**12,915**	**6,408**

1 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, Enbridge Gas Inc. (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.

On May 16, 2019, Enbridge Inc. entered into a three year, non-revolving, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

On July 18, 2019, Enbridge Inc. entered into a five year, non-revolving, bilateral credit facility for $500 million with an Asian bank.

In addition to the committed credit facilities noted above, we maintain $928 million of uncommitted demand credit facilities, of which $588 million were unutilized as at September 30, 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 2021 to 2024.

As at September 30, 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 $11,634 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 nine months ended September 30, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Algonquin Gas Transmission, LLC			
	August 2019	3.24% senior notes due August 2029	US$500
Enbridge Gas Inc.			
	August 2019	2.37% medium-term notes due August 2029	$400
	August 2019	3.01% medium-term notes due August 2049	$300
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 nine months ended September 30, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
Repayment			
	February 2019	4.10% medium-term notes	$300
	May 2019	Floating rate notes	$750
	September 2019	4.77% medium-term notes	$400
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
Enbridge Pipelines (Southern Lights) L.L.C.			
Repayment			
	June 2019	3.98% medium-term notes due 2040	US$23
Enbridge Southern Lights LP			
Repayment			
	July 2019	4.01% senior notes due 2040	$10
Westcoast Energy Inc.			
Repayment			
	January 2019	5.60% medium-term notes	$250
	January 2019	5.60% medium-term notes	$50
	May 2019	6.90% senior secured notes due 2019	$13
	May 2019	4.34% senior secured notes due 2019	$2

SUBORDINATED TERM NOTES

As at September 30, 2019 and December 31, 2018, our fixed-to-floating subordinated term notes had a principal value of $6,637 million and $7,317 million, respectively.

FAIR VALUE ADJUSTMENT

As at September 30, 2019, the net fair value adjustment for total debt assumed in the Merger Transaction was $876 million. During the three and nine months ended September 30, 2019, the amortization of the fair value adjustment, recorded as a reduction to Interest expense in the Consolidated Statements of Earnings, was $17 million and $50 million, respectively.

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 September 30, 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 nine months ended September 30, 2019 and 2018 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance as at January 1, 2019	**(770)**	**(598)**	**4,323**	**34**	**(317)**	**2,672**
Other comprehensive income/(loss) retained in AOCI	**(845)**	**167**	**(1,831)**	**26**	**—**	**(2,483)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**108**	**—**	**—**	**—**	**—**	**108**
Foreign exchange contracts[3]	**4**	**—**	**—**	**—**	**—**	**4**
Other contracts[4]	**(4)**	**—**	**—**	**—**	**—**	**(4)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**59**	**59**
	(737)	**167**	**(1,831)**	**26**	**59**	**(2,316)**
Tax impact						
Income tax on amounts retained in AOCI	**254**	**(20)**	**—**	**(7)**	**—**	**227**
Income tax on amounts reclassified to earnings	**(34)**	**—**	**—**	**—**	**(15)**	**(49)**
	220	**(20)**	**—**	**(7)**	**(15)**	**178**
Other	**—**	**—**	**—**	**(7)**	**55**	**48**
Balance as at September 30, 2019	**(1,287)**	**(451)**	**2,492**	**46**	**(218)**	**582**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance as at January 1, 2018	(644)	(139)	77	10	(277)	(973)
Other comprehensive income/(loss) retained in AOCI	167	(232)	1,495	(8)	—	1,422
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	92	—	—	—	—	92
Commodity contracts[2]	(1)	—	—	—	—	(1)
Foreign exchange contracts[3]	6	—	—	—	—	6
Other contracts[4]	10	—	—	—	—	10
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	36	36
	274	(232)	1,495	(8)	36	1,565
Tax impact						
Income tax on amounts retained in AOCI	(26)	32	—	9	—	15
Income tax on amounts reclassified to earnings	(29)	—	—	—	(8)	(37)
	(55)	32	—	9	(8)	(22)
Balance as at September 30, 2018	(425)	(339)	1,572	11	(249)	570

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Commodity costs in the Consolidated Statements of Earnings.
3 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
5 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 2.9%.

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 September 30, 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 3.1%.

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.

September 30, 2019	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
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**—**	**—**	**76**	**76**	**(66)**	**10**
Interest rate contracts	**1**	**—**	**—**	**1**	**—**	**1**
Commodity contracts	**—**	**—**	**185**	**185**	**(41)**	**144**
	1	**—**	**261**	**262**	**(107)**	**155**
Deferred amounts and other assets						
Foreign exchange contracts	**17**	**—**	**123**	**140**	**(62)**	**78**
Commodity contracts	**—**	**—**	**35**	**35**	**(7)**	**28**
Other contracts	**1**	**—**	**1**	**2**	**(1)**	**1**
	18	**—**	**159**	**177**	**(70)**	**107**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**(14)**	**(534)**	**(553)**	**66**	**(487)**
Interest rate contracts	**(258)**	**—**	**—**	**(258)**	**—**	**(258)**
Commodity contracts	**—**	**—**	**(140)**	**(140)**	**41**	**(99)**
Other Contracts	**—**	**—**	**(1)**	**(1)**	**—**	**(1)**
	(263)	**(14)**	**(675)**	**(952)**	**107**	**(845)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(1,536)**	**(1,536)**	**62**	**(1,474)**
Interest rate contracts	**(686)**	**—**	**—**	**(686)**	**—**	**(686)**
Commodity contracts	**(1)**	**—**	**(97)**	**(98)**	**7**	**(91)**
Other contracts	**(1)**	**—**	**(1)**	**(2)**	**1**	**(1)**
	(688)	**—**	**(1,634)**	**(2,322)**	**70**	**(2,252)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**12**	**(14)**	**(1,871)**	**(1,873)**	**—**	**(1,873)**
Interest rate contracts	**(943)**	**—**	**—**	**(943)**	**—**	**(943)**
Commodity contracts	**(1)**	**—**	**(17)**	**(18)**	**—**	**(18)**
Other contracts	**—**	**—**	**(1)**	**(1)**	**—**	**(1)**
	(932)	**(14)**	**(1,889)**	**(2,835)**	**—**	**(2,835)**

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
(millions of Canadian dollars)						
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:

September 30, 2019	2019	2020	2021	2022	2023	Thereafter[1]
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**1,049**	**1**	**—**	**—**	**—**	**—**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,218**	**5,355**	**4,946**	**5,182**	**1,804**	**1,856**
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**6**	**94**	**27**	**28**	**29**	**120**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**51**	**—**	**—**	**—**	**—**	**—**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**—**	**23**	**94**	**94**	**92**	**606**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**—**	**72,500**	**—**	**—**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**2,204**	**6,152**	**4,124**	**405**	**48**	**156**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**1,509**	**3,125**	**1,579**	**—**	**—**	**—**
Equity contracts *(millions of Canadian dollars)*	**29**	**20**	**34**	**—**	**—**	**—**
Commodity contracts - natural gas *(billions of cubic feet)*	**(3)**	**(26)**	**3**	**21**	**4**	**—**
Commodity contracts - crude oil *(millions of barrels)*	**7**	**1**	**—**	**—**	**—**	**—**
Commodity contracts - power *(megawatt per hour) (MW/H))*	**90**	**80**	**(3)**	**(43)**	**(43)**	**(43)**

1 As at September 30, 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 September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**2**	(16)	**(11)**	2
Interest rate contracts	**(231)**	69	**(812)**	186
Commodity contracts	**(1)**	4	**(22)**	1
Other contracts	**1**	(10)	**6**	(12)
Net investment hedges				
Foreign exchange contracts	**(1)**	25	**1**	36
	(230)	72	**(838)**	213
Amount of (gain)/loss reclassified from AOCI to earnings				
Foreign exchange contracts[1]	**2**	7	**4**	4
Interest rate contracts[2]	**36**	38	**108**	132
Commodity contracts[3]	**—**	—	**—**	(1)
Other contracts[4]	**(1)**	7	**(4)**	10
	37	52	**108**	145

1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.
2 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.
3 Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a loss of $72 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 27 months as at September 30, 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 September 30,		Nine months ended September 30,	
	2019[1]	2018	**2019**[1]	2018
(millions of Canadian dollars)				
Unrealized gain/(loss) on derivative	**—**	3	**—**	(9)
Unrealized gain/(loss) on hedged item	**—**	(3)	**—**	8
Realized gain/(loss) on derivative	**—**	(3)	**—**	(4)
Realized gain/(loss) on hedged item	**—**	3	**—**	4

1 For the three and nine months ended September 30, 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 September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**(179)**	345	**849**	(356)
Interest rate contracts[2]	**—**	6	**178**	4
Commodity contracts[3]	**73**	(113)	**(26)**	43
Other contracts[4]	**(1)**	(8)	**4**	(10)
Total unrealized derivative fair value gain/(loss), net	**(107)**	230	**1,005**	(319)

1 *For the respective nine months ended periods, reported within Transportation and other services revenues (2019 - $366 million gain; 2018 - $346 million loss) and Net foreign currency gain/(loss) (2019 - $483 million gain; 2018 - $10 million loss) in the Consolidated Statements of Earnings.*

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

3 *For the respective nine months ended periods, reported within Transportation and other services revenues (2019 - $15 million loss; 2018 - $16 million loss), Commodity sales (2019 - $418 million loss; 2018 - $42 million loss), Commodity costs (2019 - $382 million gain; 2018 - $90 million gain) and Operating and administrative expense (2019 - $25 million gain; 2018 - $11 million gain) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or United States public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at September 30, 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:

	September 30, 2019	December 31, 2018
(millions of Canadian dollars)		
Canadian financial institutions	**38**	28
United States financial institutions	**68**	107
European financial institutions	**91**	84
Asian financial institutions	**7**	6
Other[1]	**151**	337
	355	562

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

As at September 30, 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 agreements. We held no cash collateral on derivative asset exposures as at September 30, 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:

September 30, 2019	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**76**	**—**	**76**
Interest rate contracts	**—**	**1**	**—**	**1**
Commodity contracts	**9**	**44**	**132**	**185**
	9	**121**	**132**	**262**
Long-term derivative assets				
Foreign exchange contracts	**—**	**140**	**—**	**140**
Commodity contracts	**—**	**23**	**12**	**35**
Other contracts	**—**	**2**	**—**	**2**
	—	**165**	**12**	**177**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(553)**	**—**	**(553)**
Interest rate contracts	**—**	**(258)**	**—**	**(258)**
Commodity contracts	**(2)**	**(21)**	**(117)**	**(140)**
Other contracts	**—**	**(1)**	**—**	**(1)**
	(2)	**(833)**	**(117)**	**(952)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,536)**	**—**	**(1,536)**
Interest rate contracts	**—**	**(686)**	**—**	**(686)**
Commodity contracts	**—**	**(7)**	**(91)**	**(98)**
Other contracts	**—**	**(2)**	**—**	**(2)**
	—	**(2,231)**	**(91)**	**(2,322)**
Total net financial liabilities				
Foreign exchange contracts	**—**	**(1,873)**	**—**	**(1,873)**
Interest rate contracts	**—**	**(943)**	**—**	**(943)**
Commodity contracts	**7**	**39**	**(64)**	**(18)**
Other contracts	**—**	**(1)**	**—**	**(1)**
	7	**(2,778)**	**(64)**	**(2,835)**

December 31, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	47	—	47
Interest rate contracts	—	22	—	22
Commodity contracts	24	45	360	429
	24	114	360	498
Long-term derivative assets				
Foreign exchange contracts	—	62	—	62
Interest rate contracts	—	5	—	5
Commodity contracts	—	30	22	52
	—	97	22	119
Financial liabilities				
Current derivative liabilities				
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)
Long-term derivative liabilities				
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)
Total net financial liabilities				
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:

September 30, 2019	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(22)**	**Forward gas price**	**2.15**	**5.10**	**3.15**	**\$/mmbtu[2]**
Crude	**30**	**Forward crude price**	**36.94**	**64.65**	**48.61**	**\$/barrel**
NGL	**5**	**Forward NGL price**	**0.16**	**0.85**	**0.42**	**\$/gallon**
Power	**(82)**	**Forward power price**	**27.62**	**78.91**	**56.23**	**\$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(23)**	**Forward gas price**	**1.01**	**6.81**	**1.50**	**\$/mmbtu[2]**
Crude	**27**	**Forward crude price**	**45.27**	**92.65**	**52.73**	**\$/barrel**
NGL	**1**	**Forward NGL price**	**0.53**	**0.75**	**0.71**	**\$/gallon**
	(64)					

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:

	Nine months ended September 30,	
	2019	2018
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(11)**	(387)
Total gain/(loss)		
Included in earnings[1]	**67**	(146)
Included in OCI	**(22)**	—
Settlements	**(98)**	163
Level 3 net derivative liability at end of period	**(64)**	(370)

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 September 30, 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 $98 million and $102 million as at September 30, 2019 and December 31, 2018, respectively.

We have Restricted long-term investments held in trust totaling $413 million and $323 million as at September 30, 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 $580 million and $478 million as at September 30, 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 $580 million as at September 30, 2019 and December 31, 2018.

As at September 30, 2019 and December 31, 2018, our long-term debt had a carrying value of $65.7 billion and $63.9 billion, respectively, before debt issuance costs and a fair value of $71.8 billion and $64.4 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at September 30, 2019 and December 31, 2018, the non-current notes receivable had a carrying value of $94 million and $97 million, respectively, and a fair value of $94 million and $97 million, respectively.

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

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 nine months ended September 30, 2019 and 2018, we recognized an unrealized foreign exchange gain of $166 million and an unrealized foreign exchange loss of $209 million, respectively, on the translation of United States dollar denominated debt and unrealized gains of $1 million and $36 million, respectively, on the change in fair value of our outstanding foreign exchange forward contracts in OCI. During the nine months ended September 30, 2019 and 2018, we recognized realized losses of nil and $46 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and recognized realized losses of nil and $13 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period.

12. INCOME TAXES

The effective income tax rates for the three months ended September 30, 2019 and 2018 were 19.4% and 62.0%, respectively, and for the nine months ended September 30, 2019 and 2018 were 20.6% and 7.9%, respectively. The period-over-period change in the effective income tax rates is due to the buy-in of our sponsored vehicles which results in Enbridge being taxed on all of our sponsored vehicle earnings rather than on just our proportionate share, lower 2019 foreign tax rate differentials, non-recurring goodwill impairments from the third quarter of 2018, and a recovery in the second quarter of 2018 related to a change in assertion for the investment in Canadian renewable assets due to the sale which resulted in the recognition of previously unrecognized tax basis.

13. PENSION AND OTHER POSTRETIREMENT BENEFITS

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Service cost	**50**	46	**152**	162
Interest cost	**51**	39	**152**	126
Expected return on plan assets	**(84)**	(72)	**(252)**	(234)
Amortization of actuarial loss	**8**	6	**24**	21
Plan curtailments	**—**	—	**—**	2
Amortization of prior service costs	**(1)**	—	**(2)**	(1)
Net periodic benefit costs	**24**	19	**74**	76

14. LEASES

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 3 months to 28 years.

For the three and nine months ended September 30, 2019, we incurred operating lease expenses of $28 million and $84 million, respectively. Operating lease expenses are reported under Operating and administrative expenses on the Consolidated Statements of Earnings.

For the three and nine months ended September 30, 2019, operating lease payments to settle lease liabilities were $31 million and $92 million, respectively. Operating lease payments are reported under operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

(millions of Canadian dollars, except lease term and discount rate)	**September 30, 2019**	January 1, 2019
Operating leases		
Operating lease right-of-use assets, net[1]	**733**	771
Operating lease liabilities - current[2]	**99**	86
Operating lease liabilities - long-term[3]	**705**	770
Total operating lease liabilities	**804**	856
Weighted average remaining lease term		
Operating leases	**13 years**	14 years
Weighted average discount rate		
Operating leases	**4.3%**	4.3%

1 Right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported under Accounts payable and other in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported under Other long-term liabilities in the Consolidated Statements of Financial Position.

As at September 30, 2019, we have operating lease commitments as detailed below:

(millions of Canadian dollars)	Operating leases
2019[1]	30
2020	126
2021	98
2022	92
2023	82
Thereafter	666
Total undiscounted lease payments	1,094
Less imputed interest	(290)
Total operating lease commitments	804

1 For the three 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 1 month to 24 years.

(millions of Canadian dollars)	Three months ended September 30, 2019	Nine months ended September 30, 2019
Operating lease income	**67**	**196**
Variable lease income	**77**	**262**
Total lease income	**144**	**458**

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

	Operating leases
(millions of Canadian dollars)	
2019[1]	64
2020	238
2021	200
2022	189
2023	178
Thereafter	2,448
Total undiscounted lease payments	3,317

1 For the three months remaining in the 2019 fiscal year.

15. CONTINGENCIES

We and our subsidiaries are involved in various legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our 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[1]	EEP Notes[2]
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

1 As at September 30, 2019, the aggregate outstanding principal amount of SEP notes was approximately US$3.9 billion.
2 As at September 30, 2019, the aggregate outstanding principal amount of EEP notes was approximately US$4.0 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Senior Floating Rate Notes due 2020	4.530% Senior Notes due 2020
Senior Floating Rate Notes due 2020	4.850% Senior Notes due 2020
2.900% Senior Notes due 2022	4.260% Senior Notes due 2021
4.000% Senior Notes due 2023	3.160% Senior Notes due 2021
3.500% Senior Notes due 2024	4.850% Senior Notes due 2022
4.250% Senior Notes due 2026	3.190% Senior Notes due 2022
3.700% Senior Notes due 2027	3.940% Senior Notes due 2023
4.500% Senior Notes due 2044	3.940% Senior Notes due 2023
5.500% Senior Notes due 2046	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

1 As at September 30, 2019, the aggregate outstanding principal amount of the Enbridge United States dollar denominated notes was approximately US$5.9 billion.
2 As at September 30, 2019, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $6.6 billion.

In accordance with Rule 3-10 of the U.S. Securities and Exchange Commission'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 September 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	7,396	—	**7,396**
Gas distribution sales	—	—	—	454	—	**454**
Transportation and other services	—	—	—	3,748	—	**3,748**
Total operating revenues	—	—	—	11,598	—	**11,598**
Operating Expenses						
Commodity costs	—	—	—	7,216	—	**7,216**
Gas distribution costs	—	—	—	104	—	**104**
Operating and administrative	69	1	1	1,670	—	**1,741**
Depreciation and amortization	15	—	—	829	—	**844**
Impairment of long-lived assets	—	—	—	105	—	**105**
Total operating expenses	84	1	1	9,924	—	**10,010**
Operating income/(loss)	(84)	(1)	(1)	1,674	—	**1,588**
Income from equity investments	2	35	—	297	(1)	**333**
Equity earnings from consolidated subsidiaries	1,109	284	296	451	(2,140)	**—**
Other						
Net foreign currency gain/(loss)	(163)	—	—	1	119	**(43)**
Other, including other income from affiliates	512	—	46	177	(654)	**81**
Interest expense	(299)	(79)	(139)	(786)	659	**(644)**
Earnings before income taxes	1,077	239	202	1,814	(2,017)	**1,315**
Income tax (expense)/recovery	(32)	10	—	(325)	92	**(255)**
Earnings	1,045	249	202	1,489	(1,925)	**1,060**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(15)	**(15)**
Earnings attributable to controlling interests	1,045	249	202	1,489	(1,940)	**1,045**
Preference share dividends	(96)	—	—	—	—	**(96)**
Earnings attributable to common shareholders	949	249	202	1,489	(1,940)	**949**
Earnings	1,045	249	202	1,489	(1,925)	**1,060**
Total other comprehensive income/(loss)	465	(46)	8	162	(98)	**491**
Comprehensive income	1,510	203	210	1,651	(2,023)	**1,551**
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(41)	**(41)**
Comprehensive income attributable to controlling interests	1,510	203	210	1,651	(2,064)	**1,510**

Condensed Consolidating Statements of Earnings and Comprehensive Income for the three months ended September 30, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	6,919	—	6,919
Gas distribution sales	—	—	—	478	—	478
Transportation and other services	—	—	—	3,948	—	3,948
Total operating revenues	—	—	—	11,345	—	11,345
Operating Expenses						
Commodity costs	—	—	—	6,905	—	6,905
Gas distribution costs	—	—	—	112	—	112
Operating and administrative	56	8	4	1,604	(20)	1,652
Depreciation and amortization	15	—	—	784	—	799
Impairment of long-lived assets	—	—	—	4	—	4
Impairment of goodwill	—	—	—	1,019	—	1,019
Total operating expenses	71	8	4	10,428	(20)	10,491
Operating income/(loss)	(71)	(8)	(4)	917	20	854
Income from equity investments	312	38	—	339	(311)	378
Equity earnings/(losses) from consolidated subsidiaries	(272)	527	238	613	(1,106)	—
Other						
Net foreign currency gain/(loss)	97	(2)	—	(15)	(23)	57
Other, including other income/(expense) from affiliates	214	—	42	(57)	(232)	(33)
Interest expense	(272)	(77)	(140)	(423)	216	(696)
Earnings before income taxes	8	478	136	1,374	(1,436)	560
Income tax expense	(4)	—	(1)	(309)	(33)	(347)
Earnings	4	478	135	1,065	(1,469)	213
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(209)	(209)
Earnings attributable to controlling interests	4	478	135	1,065	(1,678)	4
Preference share dividends	(94)	—	—	—	—	(94)
Earnings attributable to common shareholders	(90)	478	135	1,065	(1,678)	(90)
Earnings	4	478	135	1,065	(1,469)	213
Total other comprehensive income	(707)	15	15	(163)	26	(814)
Comprehensive income/(loss)	(703)	493	150	902	(1,443)	(601)
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(102)	(102)
Comprehensive income attributable to controlling interests	(703)	493	150	902	(1,545)	(703)

Condensed Consolidating Statements of Earnings and Comprehensive Income for the nine months ended September 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	22,444	—	**22,444**
Gas distribution sales	—	—	—	3,085	—	**3,085**
Transportation and other services	—	—	—	12,188	—	**12,188**
Total operating revenues	—	—	—	37,717	—	**37,717**
Operating Expenses						
Commodity costs	—	—	—	21,910	—	**21,910**
Gas distribution costs	—	—	—	1,623	—	**1,623**
Operating and administrative	104	4	—	4,953	—	**5,061**
Depreciation and amortization	48	—	—	2,478	—	**2,526**
Impairment of long-lived assets	—	—	—	105	—	**105**
Total operating expenses	152	4	—	31,069	—	**31,225**
Operating income/(loss)	(152)	(4)	—	6,648	—	**6,492**
Income from equity investments	69	97	—	1,059	(66)	**1,159**
Equity earnings from consolidated subsidiaries	3,507	1,026	810	1,417	(6,760)	**—**
Other						
Net foreign currency gain/(loss)	1,314	—	—	(75)	(928)	**311**
Other, including other income from affiliates	1,306	1	140	412	(1,667)	**192**
Interest expense	(929)	(257)	(433)	(2,059)	1,712	**(1,966)**
Earnings before income taxes	5,115	863	517	7,402	(7,709)	**6,188**
Income tax (expense)/recovery	(252)	37	—	(1,364)	304	**(1,275)**
Earnings	4,863	900	517	6,038	(7,405)	**4,913**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(50)	**(50)**
Earnings attributable to controlling interests	4,863	900	517	6,038	(7,455)	**4,863**
Preference share dividends	(287)	—	—	—	—	**(287)**
Earnings attributable to common shareholders	4,576	900	517	6,038	(7,455)	**4,576**
Earnings	4,863	900	517	6,038	(7,405)	**4,913**
Total other comprehensive income/(loss)	(2,138)	(90)	37	(706)	686	**(2,211)**
Comprehensive income	2,725	810	554	5,332	(6,719)	**2,702**
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	23	**23**
Comprehensive income attributable to controlling interests	2,725	810	554	5,332	(6,696)	**2,725**

Condensed Consolidating Statements of Earnings and Comprehensive Income for the nine months ended September 30, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	20,638	—	20,638
Gas distribution sales	—	—	—	3,260	—	3,260
Transportation and other services	—	—	—	10,918	—	10,918
Total operating revenues	—	—	—	34,816	—	34,816
Operating Expenses						
Commodity costs	—	—	—	20,180	—	20,180
Gas distribution costs	—	—	—	1,857	—	1,857
Operating and administrative	156	12	13	4,768	(20)	4,929
Depreciation and amortization	44	—	—	2,408	—	2,452
Impairment of long lived assets	—	—	—	1,076	—	1,076
Impairment of goodwill	—	—	—	1,019	—	1,019
Total operating expenses	200	12	13	31,308	(20)	31,513
Operating income/(loss)	(200)	(12)	(13)	3,508	20	3,303
Income from equity investments	388	108	—	962	(382)	1,076
Equity earnings from consolidated subsidiaries	1,722	1,607	670	1,836	(5,835)	—
Other						
Net foreign currency gain/(loss)	(273)	2	—	(8)	108	(171)
Other, including other income from affiliates	732	2	107	(21)	(759)	61
Interest expense	(801)	(221)	(413)	(1,379)	772	(2,042)
Earnings before income taxes	1,568	1,486	351	4,898	(6,076)	2,227
Income tax (expense)/recovery	130	—	(1)	(291)	(15)	(177)
Earnings	1,698	1,486	350	4,607	(6,091)	2,050
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(352)	(352)
Earnings attributable to controlling interests	1,698	1,486	350	4,607	(6,443)	1,698
Preference share dividends	(272)	—	—	—	—	(272)
Earnings attributable to common shareholders	1,426	1,486	350	4,607	(6,443)	1,426
Earnings	1,698	1,486	350	4,607	(6,091)	2,050
Total other comprehensive income	1,543	45	29	252	(132)	1,737
Comprehensive income	3,241	1,531	379	4,859	(6,223)	3,787
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(546)	(546)
Comprehensive income attributable to controlling interests	3,241	1,531	379	4,859	(6,769)	3,241

Condensed Consolidating Statements of Financial Position as at September 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Assets						
Current assets						
Cash and cash equivalents	—	6	1	808	—	**815**
Restricted cash	9	—	—	48	—	**57**
Accounts receivable and other	164	1	7	5,661	—	**5,833**
Accounts receivable from affiliates	783	3	28	1,370	(2,095)	**89**
Short-term loans receivable from affiliates	3,992	—	5,175	5,160	(14,327)	**—**
Inventory	—	—	—	1,261	—	**1,261**
	4,948	10	5,211	14,308	(16,422)	**8,055**
Property, plant and equipment, net	202	—	—	94,177	—	**94,379**
Long-term loans receivable from affiliates	51,727	73	2,437	40,637	(94,874)	**—**
Investments in subsidiaries	79,746	18,903	6,077	15,319	(120,045)	**—**
Long-term investments	1,752	950	—	14,710	(581)	**16,831**
Restricted long-term investments	—	—	—	413	—	**413**
Deferred amounts and other assets	1,527	1	4	9,709	(1,375)	**9,866**
Intangible assets, net	232	—	—	1,984	—	**2,216**
Goodwill	—	—	—	33,668	—	**33,668**
Deferred income taxes	681	—	—	532	—	**1,213**
Total assets	140,815	19,937	13,729	225,457	(233,297)	**166,641**
Liabilities and equity						
Current liabilities						
Short-term borrowings	—	—	—	1,269	—	**1,269**
Accounts payable and other	921	31	2	6,376	(200)	**7,130**
Accounts payable to affiliates	842	1	1,384	(85)	(2,095)	**47**
Interest payable	222	24	89	231	—	**566**
Short-term loans payable to affiliates	367	2,437	2,356	9,167	(14,327)	**—**
Current portion of long-term debt	2,092	529	662	1,253	—	**4,536**
	4,444	3,022	4,493	18,211	(16,622)	**13,548**
Long-term debt	25,232	4,526	4,528	26,593	—	**60,879**
Other long-term liabilities	2,361	35	21	8,391	(1,375)	**9,433**
Long-term loans payable to affiliates	39,936		1,456	53,482	(94,874)	**—**
Deferred income taxes	—	266	—	14,218	(4,379)	**10,105**
	71,973	7,849	10,498	120,895	(117,250)	**93,965**
Equity						
Controlling interests[1]	68,842	12,088	3,231	104,562	(119,436)	**69,287**
Noncontrolling interests	—	—	—	—	3,389	**3,389**
	68,842	12,088	3,231	104,562	(116,047)	**72,676**
Total liabilities and equity	140,815	19,937	13,729	225,457	(233,297)	**166,641**

1 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
(millions of Canadian dollars)						
Assets						
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
Total assets	101,205	20,877	12,629	180,532	(148,338)	166,905
Liabilities and equity						
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[1]	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
Total liabilities and equity	101,205	20,877	12,629	180,532	(148,338)	166,905

1 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 nine months ended September 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Net cash provided by operating activities	1,766	1,305	1,027	6,676	(3,369)	**7,405**
Investing activities						
Capital expenditures	(56)	—	—	(3,872)	—	**(3,928)**
Long-term investments and restricted long-term investments	(19)	(10)	—	(989)	—	**(1,018)**
Distributions from equity investments in excess of cumulative earnings	—	17	850	268	(850)	**285**
Additions to intangible assets	(55)	—	—	(81)	—	**(136)**
Affiliate loans, net	—	—	—	(232)	—	**(232)**
Contributions to subsidiaries	(2,876)	—	(8)	—	2,884	**—**
Return of share capital from subsidiary companies	4,921	—	—	—	(4,921)	**—**
Advances to affiliates	(47,536)	—	(2,088)	(56,349)	105,973	**—**
Repayment of advances to affiliates	5,858	—	501	12,367	(18,726)	**—**
Net cash (used in)/provided by investing activities	(39,763)	7	(745)	(48,888)	84,360	**(5,029)**
Financing activities						
Net change in short-term borrowings	—	—	—	245	—	**245**
Net change in commercial paper and credit facility draws	4,342	(2,011)	(1,017)	2,051	—	**3,365**
Debenture and term note issues, net of issue costs	—	—	—	2,553	—	**2,553**
Debenture and term note repayments	(1,450)	—	(1,189)	(355)	—	**(2,994)**
Contributions from noncontrolling interests	—	—	—	—	10	**10**
Distributions to noncontrolling interests	—	—	—	—	(194)	**(194)**
Contributions from redeemable noncontrolling interests	—	—	—	—	—	**—**
Distributions to redeemable noncontrolling interests	—	—	—	—	—	**—**
Contributions from parents	—	—	—	2,884	(2,884)	**—**
Distributions to parents	—	(1,014)	(489)	(7,821)	9,324	**—**
Redemption of preferred shares	—	—	—	(300)	—	**(300)**
Common shares issued	18	—	—	—	—	**18**
Preference share dividends	(287)	—	—	—	—	**(287)**
Common share dividends	(4,480)	—	—	—	—	**(4,480)**
Advances from affiliates	46,917	5,091	4,341	49,624	(105,973)	**—**
Repayment of advances from affiliates	(7,063)	(3,383)	(1,921)	(6,359)	18,726	**—**
Other	—	(5)	(6)	(49)	—	**(60)**
Net cash provided by/(used in) financing activities	37,997	(1,322)	(281)	42,473	(80,991)	**(2,124)**
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	(17)	—	**(17)**
Net increase/(decrease) in cash and cash equivalents and restricted cash	—	(10)	1	244	—	**235**
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	6	1	856	—	**872**

Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Net cash (used in)/provided by operating activities	1,449	1,536	(298)	7,901	(2,589)	7,999
Investing activities						
Capital expenditures	(17)	—	—	(4,567)	—	(4,584)
Long-term investments and restricted long-term investments	(69)	(12)	—	(1,077)	67	(1,091)
Distributions from equity investments in excess of cumulative earnings	65	29	793	1,214	(858)	1,243
Additions to intangible assets	(33)	—	—	(458)	—	(491)
Affiliate loans, net	—	—	—	(50)	—	(50)
Proceeds from dispositions	—	—	—	1,913	—	1,913
Reimbursement of capital expenditures	—	—	—	—	—	—
Contributions to subsidiaries	(7,179)	(78)	(10)	—	7,267	—
Return of share capital from subsidiary companies	3,624	—	—	—	(3,624)	—
Advances to affiliates	(5,030)	—	(1,206)	(3,380)	9,616	—
Repayment of advances to affiliates	7,395	515	1,270	2,290	(11,470)	—
Other	—	—	—	(12)	—	(12)
Net cash (used in)/provided by investing activities	(1,244)	454	847	(4,127)	998	(3,072)
Financing activities						
Net change in short-term borrowings	—	—	—	(196)	—	(196)
Net change in commercial paper and credit facility draws	(341)	(758)	286	(1,545)	—	(2,358)
Debenture and term note issues, net of issue costs	2,556	—	—	981	—	3,537
Debenture and term note repayments	—	(644)	(509)	(2,604)	—	(3,757)
Sale of noncontrolling interest in subsidiary	—	—	—	1,289	—	1,289
Contributions from noncontrolling interests	—	—	—	—	23	23
Distributions to noncontrolling interests	—	—	—	—	(637)	(637)
Contributions from redeemable noncontrolling interests	—	—	—	—	62	62
Distributions to redeemable noncontrolling interests	—	—	—	—	(264)	(264)
Contributions from parents	—	—	—	7,267	(7,267)	—
Distributions to parents	—	(1,407)	(499)	(5,914)	7,820	—
Common shares issued	17	—	—	—	—	17
Preference share dividends	(268)	—	—	—	—	(268)
Common share dividends	(2,254)	—	—	—	—	(2,254)
Advances from affiliates	535	821	2,024	6,236	(9,616)	—
Repayment of advances from affiliates	(443)	—	(1,847)	(9,180)	11,470	—
Other	—	(6)	(3)	4	—	(5)
Net cash provided by/(used in) financing activities	(198)	(1,994)	(548)	(3,662)	1,591	(4,811)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	23	—	23
Net increase/(decrease) in cash and cash equivalents and restricted cash	7	(4)	1	135	—	139
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	10	1	706	—	726

17. SUBSEQUENT EVENTS

On October 1, 2019, we closed the sale of EGNB for proceeds of approximately $331 million, subject to customary closing adjustments. Refer to *Note 6. Acquisitions and Dispositions* for further discussion of the transaction.

On October 3, 2019, we completed an offering of $1.0 billion of medium-term notes that mature in 10 years. The notes carry a coupon rate of 2.99% payable semi-annually.

On November 1, 2019, we closed the sale of the issued and outstanding shares of St. Lawrence Gas for proceeds of approximately $72 million (US$55 million), subject to customary closing adjustments. Refer to *Note 6. Acquisitions and Dispositions* for further discussion of the transaction.

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, and our audited updated consolidated financial statements and accompanying footnotes for the year ended December 31, 2018.

As of the end of the second quarter of 2019, we have qualified as a foreign private issuer for purposes of the U.S. Securities Exchange Act of 1934, as amended (Exchange Act). We intend to continue to file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K with the U.S. Securities and Exchange Commission instead of filing the reporting forms available to foreign private issuers. We also intend to maintain our Form S-3 registration statements.

RECENT DEVELOPMENTS

CANADIAN LINE 3 REPLACEMENT PROGRAM TO BE PLACED INTO SERVICE

On August 30, 2019, we announced that we have reached a commercial agreement with shippers to place the Canadian L3R Program into service on December 1, 2019. The agreement reflects the importance of this safety-driven maintenance project to protecting the environment and ensuring the continued safe and reliable operations of our Mainline System well into the future.

On August 30, 2019, we also filed, with the Canada Energy Regulator (CER), a tariff with a temporary surcharge for this offering with an effective date of December 1, 2019. This tariff will be superseded by the full negotiated Line 3 tariff upon completion of the U.S. L3R Program.

STATE OF MINNESOTA PERMITTING TIMELINE FOR U.S. LINE 3 REPLACEMENT PROGRAM

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the Minnesota Public Utilities Commission's (MNPUC's) adequacy determination of the Final Environmental Impact Statement (FEIS) for the U.S. L3R Program. While denying eight of the nine appealed items, the Minnesota Court of Appeals identified one issue that led them to reverse the adequacy determination. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents' petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019. We will continue to consult with relevant state agencies about next steps.

At this time, we cannot determine when all necessary permits will be issued pending receipt of further information from the MNPUC on a timeline to complete this work. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

MAINLINE SYSTEM CONTRACTING

On August 2, 2019, we launched an open season for transportation services on our Mainline System. The open season provided shippers with the opportunity to enter into long-term contracts for priority access on the Mainline System upon maturity of the current Competitive Tolling Settlement agreement on June 30, 2021.

On September 27, 2019, the CER ordered that we may not offer firm service to prospective shippers on our Mainline System until such firm service, including all associated tolls and terms and conditions of service, has been approved by the CER. While this decision was a significant departure from past regulatory precedents, the CER noted that its decision to hold a regulatory review prior to the open season does not prejudice our ability to offer long term priority access contracts on the Mainline System.

The open season is the result of 18 months of extensive negotiations with our diverse customer base and was formulated in direct response to our core customer base who want toll certainty and priority access. These shippers, which represent the majority of Mainline System throughput, continue to support the offering.

We plan to file an application with the CER seeking approval of a firm service offering prior to the end of the year.

ENBRIDGE GAS NEW BRUNSWICK BUSINESS

On October 1, 2019, we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power & Utilities Corp., for proceeds of approximately $331 million, subject to customary closing adjustments.

ST. LAWRENCE GAS COMPANY

On November 1, 2019, we closed the sale of the issued and outstanding shares of St. Lawrence Gas for proceeds of approximately $72 million, subject to customary closing adjustments.

ENBRIDGE GAS INC. 2019 RATE APPLICATION

In September 2019, EGI received a Decision and Order from the Ontario Energy Board (OEB) on its application for 2019 rates. The 2019 rate application was filed in December 2018 in accordance with the parameters of EGI's OEB approved Price Cap Incentive Regulation rate setting mechanism and represents the first year of a five-year term. The Decision and Order approved an effective date for base rates of April 1, 2019, and the inclusion of incremental capital module amounts to allow for the recovery of incremental capital investments.

SECURED GROWTH PROJECTS UPDATE

On August 2, 2019, we announced that we are proceeding with $2 billion of new growth projects across several business segments. We now have a $19 billion inventory of secured projects at various stages of execution which are scheduled to come into service between 2019 and 2023. For further details refer to *Growth Projects - Commercially Secured Projects*.

TEXAS EASTERN PIPELINE RUPTURE

On August 1, 2019, a rupture occurred on Line 15, a 30-inch natural gas pipeline that is a component of the Texas Eastern natural gas pipeline system in Lincoln County, Kentucky. While the two adjacent pipelines have been returned to service, Line 15 remains shut down in the affected area and the timeline for its return to service has not yet been determined. There was one fatality. We are continuing to support the National Transportation Safety Board in its investigation, the community and the community members who were impacted by the rupture. The Texas Eastern natural gas pipeline system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York.

Due to the incident, before expected recoveries, we experienced lower revenues and higher operating costs of $18 million in the third quarter of 2019. Texas Eastern Transmission, LP (Texas Eastern) is included in a comprehensive insurance program that is maintained for our subsidiaries and affiliates, which includes liability, property and business interruption insurance.

TEXAS EASTERN RATE CASE

On June 1, 2019, Texas Eastern put into effect its updated rates. These increased recourse rates are subject to refund and interest. Following extensive negotiations on the Texas Eastern rate case, we reached an agreement with shippers and filed the Stipulation and Agreement with the FERC on October 28, 2019. We expect an approval in the second quarter of 2020.

RESULTS OF OPERATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars, except per share amounts)				
Segment earnings/(loss) before interest, income taxes and depreciation and amortization				
Liquids Pipelines	**1,646**	1,875	**5,710**	4,353
Gas Transmission and Midstream	**772**	(60)	**2,733**	1,080
Gas Distribution	**252**	256	**1,304**	1,262
Renewable Power Generation and Transmission	**82**	51	**300**	286
Energy Services	**91**	(96)	**318**	108
Eliminations and Other	**(40)**	29	**315**	(368)
Depreciation and amortization	**(844)**	(799)	**(2,526)**	(2,452)
Interest expense	**(644)**	(696)	**(1,966)**	(2,042)
Income tax expense	**(255)**	(347)	**(1,275)**	(177)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(15)**	(209)	**(50)**	(352)
Preference share dividends	**(96)**	(94)	**(287)**	(272)
Earnings/(loss) attributable to common shareholders	**949**	(90)	**4,576**	1,426
Earnings/(loss) per common share	**0.47**	(0.05)	**2.27**	0.84
Diluted earnings/(loss) per common share	**0.47**	(0.05)	**2.27**	0.84

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Three months ended September 30, 2019, compared with the three months ended September 30, 2018

Earnings Attributable to Common Shareholders were net positively impacted by $848 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2019 of a goodwill impairment charge of $1,019 million after-tax attributable to us in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- the absence in 2019 of a loss of $74 million ($117 million after-tax attributable to us) in 2018 resulting from the sale of Midcoast Operating, L.P. and its subsidiaries (together, MOLP); and
- the absence in 2019 of asset monetization transaction costs of $45 million ($49 million after-tax attributable to us) recorded in 2018 attributable to divestiture activity in the quarter.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a non-cash, unrealized derivative fair value loss of $79 million ($52 million after-tax attributable to us) in 2019, compared with a gain of $264 million ($150 million after-tax attributable to us) 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 prices risks;
- a loss of $62 million ($47 million after-tax attributable to us) in 2019 related to asset write-down and goodwill impairment losses at our equity investee, DCP Midstream, LLC.; and
- a loss of $105 million ($79 million after-tax attributable to us) in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project.

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 $191 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 Mainline System ex-Gretna throughput driven by an increase in supply and continuous capacity optimization;
- increased earnings from our Liquids Pipelines segment due to higher Flanagan South Pipeline, Seaway Crude Pipeline System and Bakken Pipeline System throughput period-over-period;
- contributions from new Gas Transmission and Midstream assets placed into service in the fourth quarter of 2018; and
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the buy-in of our sponsored vehicles in the fourth quarter of 2018.

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 the second half of 2018; and
- higher operating costs on our Gas Transmission and Midstream assets primarily due to higher pipeline integrity costs.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

Earnings Attributable to Common Shareholders were net positively impacted by $2,439 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2019 of a goodwill impairment charge of $1,019 million after-tax attributable to us in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- the absence in 2019 of a loss of $913 million ($701 million after-tax attributable to us) in 2018 on 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 $74 million ($117 million after-tax attributable to us) in 2018 resulting from the sale of MOLP;
- the absence in 2019 of a loss of $154 million ($95 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 $1,052 million ($779 million after-tax attributable to us) in 2019, compared with a loss of $295 million ($146 million after-tax attributable to us) 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 prices risks;
- employee severance, transition and transformation costs of $88 million ($78 million after-tax attributable to us) in 2019, compared with $143 million ($137 million after-tax attributable to us) in 2018; and
- the absence in 2019 of asset monetization transaction costs of $65 million ($64 million after-tax attributable to us) recorded in 2018 attributable to divestiture activity in the period.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of $171 million ($131 million after-tax attributable to us) compared to $23 million ($17 million after-tax attributable to us) in 2018;
- a loss of $62 million ($47 million after-tax attributable to us) in 2019 related to asset write-down and goodwill impairment losses at our equity investee, DCP Midstream, LLC.;
- a loss of $105 million ($79 million after-tax attributable to us) in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- 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; and
- the absence in 2019 of a deferred income tax recovery of $267 million ($196 million attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets.

After taking into consideration the factors above, the remaining $711 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 IJT Benchmark Toll and higher Mainline System ex-Gretna throughput driven by an increase in supply and continuous capacity optimization;
- increased earnings from our Liquids Pipelines segment due to higher Flanagan South Pipeline, Seaway Crude Pipeline System and Bakken Pipeline System throughput period-over-period;
- contributions from new Gas Transmission and Midstream assets placed into service in the fourth quarter of 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 in 2019 of forecasted earnings sharing which was recorded in 2018;
- increased earnings from our Energy Services segment due to the widening of certain location differentials during the second half of 2018 and the first quarter of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019;
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the buy-in of our sponsored vehicles in the fourth quarter of 2018; 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 $1.29 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 the second half of 2018;
- higher operating costs on our Gas Transmission and Midstream assets primarily due to higher pipeline integrity costs; and
- higher income tax expense due to higher earnings, the buy-in of our United States sponsored vehicles in the fourth quarter of 2018 and lower foreign tax rate differentials in 2019.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**1,646**	1,875	**5,710**	4,353

Three months ended September 30, 2019, compared with the three months ended September 30, 2018

EBITDA was negatively impacted by $422 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized loss of $180 million in 2019 compared with a gain of $211 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 gain of $28 million in 2018 on the sale of pipe related to our Sandpiper Project.

After taking into consideration the factors above, the remaining $193 million increase is primarily explained by the following significant business factors:

- a higher IJT Benchmark Toll of US$4.21 in 2019 compared with US$4.15 in 2018;
- higher Mainline System ex-Gretna throughput of 2,714 thousands of barrels per day (kbpd) in 2019 compared with 2,578 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 driven by strong Gulf Coast demand resulting from favorable price differentials; and
- higher Bakken Pipeline System throughput period-over-period driven by strong production in the region.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of US$1.19 in 2019 compared with US$1.26 in 2018.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was positively impacted by $925 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of $390 million in 2019 compared with a loss of $362 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 $154 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.

The positive factors above were partially offset by the absence in 2019 of a gain of $28 million in 2018 on the sale of pipe related to our Sandpiper Project.

After taking into consideration the factors above, the remaining $432 million increase is primarily explained by the following significant business factors:

- a higher IJT Benchmark Toll of US$4.17 in 2019 compared with US$4.10 in 2018;
- higher Mainline System ex-Gretna throughput of 2,698 kbpd in 2019 compared with 2,613 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 driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest in the first half of 2019 and strong Gulf Coast demand resulting from favorable price differentials;
- higher Bakken Pipeline System throughput period-over-period driven by strong production in the region; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.29 in 2018.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of US$1.19 in 2019 compared with US$1.26 in 2018.

GAS TRANSMISSION AND MIDSTREAM

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**772**	(60)	**2,733**	1,080

Three months ended September 30, 2019, compared with the three months ended September 30, 2018

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately $85 million from the sale of MOLP on August 1, 2018 and the sale of the provincially regulated portion of our Canadian gas gathering and processing businesses on October 1, 2018.

EBITDA was positively impacted by $926 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2019 of a goodwill impairment charge of $1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale; and
- the absence in 2019 of a loss of $74 million in 2018 resulting from the sale of MOLP.

The positive factors above were partially offset by the following:

- a loss of $62 million in 2019 related to asset write-down and goodwill impairment losses at our equity investee, DCP Midstream, LLC.; and
- a loss of $105 million in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project.

After taking into consideration the factors above, the remaining $9 million decrease is primarily explained by the following significant business factors:

- higher operating costs on our US Gas Transmission assets primarily due to higher pipeline integrity costs;
- lower revenues and higher operating costs from US Gas Transmission due to the Texas Eastern natural gas pipeline system incident in Lincoln County, Kentucky, refer to *Recent Developments - Texas Eastern Pipeline Rupture;* and
- decreased fractionation margins at our Aux Sable joint venture driven by lower NGL prices.

The negative business factors above were partially offset by contributions from Valley Crossing Pipeline and certain other Offshore and US Gas Transmission assets that were placed into service during the fourth quarter of 2018.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately $240 million from the sale of MOLP on August 1, 2018 and the sale of the provincially regulated portion of our Canadian gas gathering and processing businesses on October 1, 2018.

EBITDA was positively impacted by $1,849 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2019 of a goodwill impairment charge of $1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- 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; and
- the absence in 2019 of a loss of $74 million in 2018 resulting from the sale of MOLP.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of $62 million in 2019 related to asset write-down and goodwill impairment losses at our equity investee, DCP Midstream, LLC.; and
- a loss of $105 million in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project.

After taking into consideration the factors above, the remaining $44 million increase is explained by the following significant business factors:

- contributions from Valley Crossing Pipeline and certain other Offshore and US Gas Transmission assets that were placed into service during the fourth quarter of 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 $1.29 in 2018.

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

- higher operating costs on our US Gas Transmission assets primarily due to higher pipeline integrity costs;
- lower revenues and higher operating costs from US Gas Transmission due to the Texas Eastern natural gas pipeline system incident in Lincoln County, Kentucky, refer to *Recent Developments - Texas Eastern Pipeline Rupture;* and
- decreased fractionation margins at our Aux Sable joint venture driven by lower NGL prices.

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**252**	256	**1,304**	1,262

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

Three months ended September 30, 2019, compared with the three months ended September 30, 2018

EBITDA decreased by $4 million primarily explained by accelerated capital cost allowance deductions reflected as a pass through to customers.

This negative factor was partially offset by the following:

- higher distribution charges primarily resulting from increases in distribution rates and customer base; and
- synergy captures realized from the amalgamation of EGD and Union Gas.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was negatively impacted by $22 million due to certain unusual, infrequent or other non-operating factors, primarily explained by employee severance costs of $37 million in 2019 related to the amalgamation of EGD and Union Gas.

This negative factor was partially offset by the following unusual, infrequent or other non-operating factors:

- a non-cash, unrealized gain of $9 million in 2019 compared with a gain of $3 million in 2018 arising from the change in the mark-to-market value of our equity investee's, Noverco Inc.'s derivative financial instruments; and
- 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 in the United States.

After taking into consideration the factors above, the remaining $64 million increase is primarily explained by the following significant business factors:

- increased earnings of $41 million resulting from colder weather experienced in our franchise service areas when compared to the corresponding period in 2018;
- increased earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base;

- the absence in 2019 of forecasted earnings sharing which was recorded in 2018 under EGD's previous incentive rate structure; and
- synergy captures realized from the amalgamation of EGD and Union Gas.

The positive business factors above were partially offset by accelerated capital cost allowance deductions reflected as a pass through to customers.

RENEWABLE POWER GENERATION AND TRANSMISSION

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**82**	51	**300**	286

Three months ended September 30, 2019, compared with the three months ended September 30, 2018

EBITDA was positively impacted by $22 million due to certain unusual, infrequent and other non-operating factors, primarily explained by the absence in 2019 of a loss of $20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facility and its subsequent expansion.

After taking into consideration the factor above, the remaining $9 million increase is primarily explained by the following significant business factors:

- stronger wind resources at Canadian and United States wind facilities; and
- higher contributions from the Rampion Offshore Wind Project.

The positive business factors above were partially offset by higher mechanical repair costs at certain United States wind facilities.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was positively impacted by $46 million due to certain unusual, infrequent and other non-operating factors, primarily explained by the following:

- the absence in 2019 of a loss of $20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facility and its expansion;
- 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.

After taking into consideration the factors above, the remaining $32 million decrease is primarily explained by the following significant business factors:

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

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

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

ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**91**	(96)	**318**	108

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 September 30, 2019, compared with the three months ended September 30, 2018

EBITDA was net positively impacted by $170 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of $91 million in 2019 compared with a loss of $99 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices. This positive factor was offset by a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of $27 million in 2019 compared with $7 million in 2018.

After taking into consideration the factors above, the remaining $17 million increase is primarily due to increased earnings from Energy Services' crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first quarter of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was positively impacted by $13 million due to certain unusual, infrequent and other non-operating factors, primarily explained by a non-cash, unrealized gain of $198 million in 2019 compared with a gain of $37 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices. This positive factor was offset by a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of $171 million in 2019 compared with $23 million in 2018.

After taking into consideration the factors above, the remaining $197 million increase is primarily due to increased earnings from Energy Services' crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first quarter of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

ELIMINATIONS AND OTHER

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**(40)**	29	**315**	(368)

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 September 30, 2019, compared with the three months ended September 30, 2018

EBITDA was negatively impacted by $98 million due to certain unusual, infrequent and other non-operating factors, primarily explained by a non-cash, unrealized gain of $9 million in 2019 compared with a gain of $131 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. This negative factor was offset by the absence in 2019 of asset monetization transaction costs of $25 million in 2018.

After taking into consideration the factors above, the remaining $29 million increase is primarily explained by the following significant business factors:

- lower operating and administrative costs in the third quarter of 2019; and
- a realized loss of $50 million in 2019 compared with a loss of $59 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.

Nine months ended September 30, 2019, compared with the nine months ended September 30, 2018

EBITDA was positively impacted by $592 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of $453 million in 2019 compared with nil 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;
- employee severance, transition and transformation costs of $45 million in 2019 compared with $102 million in 2018; and
- the absence in 2019 of asset monetization transaction costs of $45 million in 2018.

After taking into consideration the factors above, the remaining $91 million increase is primarily explained by lower operating and administrative costs in 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 fourth quarter of 2018.

The positive business factor above was partially offset by a realized loss of $166 million in 2019 compared with a loss of $154 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 – COMMERCIALLY SECURED PROJECTS

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

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.	Other - Canada[3]	100%	$0.3 billion	$0.3 billion	Complete	In-service
2.	Gray Oak Pipeline Project	22.8%	US$0.7 billion	US$0.4 billion	Under construction	Q4 - 2019
3.	Canadian Line 3 Replacement Program	100%	$5.3 billion	$4.8 billion	Substantially complete	Q4 - 2019
4.	U.S. Line 3 Replacement Program	100%	US$2.9 billion	US$1.2 billion	Pre-construction	2H - 2020[4]
5.	Other - United States[5]	100%	US$0.6 billion	US$0.5 billion	Various stages	2020 - 2021
GAS TRANSMISSION AND MIDSTREAM						
6.	Atlantic Bridge	100%	US$0.6 billion	US$0.5 billion	Various stages	2019 - 2020
7.	Spruce Ridge Project	100%	$0.5 billion	$0.2 billion	Pre-construction	2H - 2021
8.	T-South Reliability & Expansion Program	100%	$1.0 billion	$0.3 billion	Pre-construction	2H - 2021
9.	Other - United States[6]	Various	US$1.2 billion	US$0.5 billion	Various stages	2019 - 2023
GAS DISTRIBUTION						
10.	Other - Canada	100%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2020
11.	Dawn-Parkway Expansion	100%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021
RENEWABLE POWER GENERATION AND TRANSMISSION						
12.	Hohe See Offshore Wind Project and Expansion	25%	$1.1 billion (€0.67 billion)	$0.8 billion (€0.5 billion)	Substantially complete	Q4 - 2019
13.	Other - Canada	25%	$0.2 billion	No significant expenditures to date	Under construction	2H - 2021
14.	Saint-Nazaire France Offshore Wind Project	50%	$1.8 billion (€1.2 billion)	No significant expenditures to date	Under construction	2H - 2022

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to September 30, 2019.
3 Athabasca Oil Corporation Lateral Acquisition closed in the first quarter of 2019.
4 Update to in-service date pending MNPUC review of FEIS remediation.
5 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.
6 Includes the US$0.2 billion Stratton Ridge Project placed into service in the second quarter of 2019 and the US$0.1 billion Generation Pipeline Acquisition closed in the third quarter of 2019.

A full description of each of our projects is provided in our Annual Report on Form 10-K. 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 barrels per day, subject to additional shipper commitments. During the first quarter of 2019 project execution forecasts were revised to reflect updated construction cost estimates and timing, with an expected in-service date by the end of the year.

- **Canadian Line 3 Replacement Program -** on August 30, 2019, we announced that we have reached a commercial agreement with shippers to place the Canadian L3R Program into service on December 1, 2019. Refer to *Recent Developments - Canadian Line 3 Replacement Program to be placed into service.*

GAS TRANSMISSION AND MIDSTREAM

- **Atlantic Bridge -** expansion of the Algonquin Gas Transmission systems to transport 133 million cubic feet per day (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 New York, 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 reached full in-service in October 2019, upon which we began earning incremental revenues. Due to ongoing permitting delays in Massachusetts, the revised expected in service date for the Massachusetts portion of the project is the second half of 2020.

- **Spruce Ridge Project** - a natural gas pipeline expansion of Westcoast Energy Inc.'s British Columbia (BC) Pipeline in northern BC. The project will provide additional capacity of up to 402 mmcf/d. Due to commercial delays, the revised expected in-service date is the second half of 2021.

- **T-South Reliability & Expansion Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in southern BC that will provide improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/Canada border. The projects were approved by the CER in September 2019 and have an expected 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 83 mmcf/d with an expected in-service date by the end of 2021.

RENEWABLE POWER GENERATION AND TRANSMISSION

- **Hohe See Offshore Wind Project and Expansion** - a wind project located in the North Sea, off the coast of Germany that will generate approximately 497-MW, with an additional 112-MW from the expansion. The Hohe See Project and Expansion is backed by a government legislated 20-year revenue support mechanism. The project generated first power in July 2019 and full operating capacity was reached in October 2019. The project expansion is expected to be placed into service by the end of the year.

- **Saint Nazaire France Offshore Wind Project -** a wind project located off the west coast of France that will generate approximately 480 megawatts. We hold an effective 50% interest with EDF Renouvelables. Project revenues are backed by a 20-year fixed price power purchase agreement with added power production protection. Our share of the total investment in the project is $1.8 billion, with an equity contribution of $0.3 billion. The remainder of the construction will be financed through non-recourse project level debt. The project is expected to be placed into service in the second half of 2022.

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program
On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the MNPUC's adequacy determination of the FEIS for the U.S. L3R Program. While denying eight of the nine issues on appeal, the Minnesota Court of Appeals identified one issue that led them to reverse the adequacy determination. The Minnesota Court of Appeals remanded and directed the MNPUC to perform spill modeling analysis within the Lake Superior Watershed. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents’ petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019.

As for environmental permits, the spill modeling required by the Minnesota Court of Appeals is a prerequisite to finalizing other state permits. On September 27, 2019, the Minnesota Pollution Control Agency (MPCA) issued a denial without prejudice of the U.S. L3R Program's 401 Water Quality Certification (WQC). This action was expected since the MPCA is prohibited by State law from issuing a final 401 WQC until the FEIS has been revised to reflect the June 3, 2019 Minnesota Court of Appeals decision requiring additional spill modelling.

The MNPUC’s statement on July 3, 2019 indicated that the agency will seek public comment and work expeditiously to address the FEIS deficiency. Additionally, the State permitting agencies’ previously stated their permitting efforts would continue in parallel with the MNPUC process and that work continues to advance accordingly. Following the Department of Commerce’s completion of its spill modelling analysis, we expect further details regarding the MNPUC’s process and timelines, after which we expect permitting agencies to re-align their timelines to the MNPUC process. At this time, we cannot determine when all necessary permits will be issued pending receipt of further information from the MNPUC on a timeline to complete this work.

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. 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. In the second quarter of 2019 the United States Maritime Administration and the United States Coast Guard temporarily suspended processing of Texas COLT Offshore Loading Project's deepwater port license application to assess further information regarding the addition of a marine vapor control system to the original project design. We continue to work closely with Federal and State permitting agencies. During 2019 we acquired the positions previously held by our other partners.

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline -** the Rio Bravo Pipeline (Rio Bravo) and other natural gas pipelines in South Texas will transport natural gas to NextDecade's Rio Grande LNG project located in Brownsville, Texas. Rio Bravo is designed to transport 4.5 billion cubic feet per day of natural gas from the Agua Dulce area to Rio Grande LNG. Along with NextDecade Corporation, we announced a Memorandum of Understanding (MOU) to jointly pursue this development and we anticipate finalizing definitive documentation reflecting the terms of the MOU in the fourth quarter of 2019.

- **Texas Eastern Venice Lateral Project -** a reversal and expansion of Texas Eastern’s Line 40 from its existing Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern’s Larose compressor station. The project will deliver 1.5 billion cubic feet of feed gas to Venture Global’s proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The project is expected to be placed into 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. Our current financing plan does not require the use of equity funding alternatives and was the leading principle behind the suspension of our Dividend Reinvestment and Share Purchase Plan in November 2018.

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 September 30, 2019:

	Maturity Dates	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2021-2024	**7,024**	**6,400**	**624**
Enbridge (U.S.) Inc.	2021-2024	**7,282**	**2,680**	**4,602**
Enbridge Pipelines Inc.	2021	**3,000**	**2,555**	**445**
Enbridge Gas Inc.	2019-2021	**2,017**	**1,280**	**737**
Total committed credit facilities		**19,323**	**12,915**	**6,408**

1 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.

On May 16, 2019, Enbridge Inc. entered into a three year, non-revolving, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

On July 18, 2019, Enbridge Inc. entered into a five year, non-revolving, bilateral credit facility for $500 million with an Asian Bank.

In addition to the committed credit facilities noted above, we maintain $928 million of uncommitted demand credit facilities, of which $588 million were unutilized as at September 30, 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 $7,223 million as at September 30, 2019, was inclusive of $815 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 September 30, 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 nine months ended September 30, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars)			
Algonquin Gas Transmission, LLC.			
	August 2019	3.24% senior notes due August 2029	US$500
Enbridge Gas Inc.			
	August 2019	2.37% medium-term notes due August 2029	$400
	August 2019	3.01% medium-term notes due August 2049	$300
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

On October 3, 2019, Enbridge Inc. completed an offering of $1.0 billion of medium-term notes that mature in 10 years. The notes carry a coupon rate of 2.99% payable semi-annually.

LONG-TERM DEBT REPAYMENTS

During the nine months ended September 30, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
Repayment			
	February 2019	4.10% medium-term notes	$300
	May 2019	Floating rate notes	$750
	September 2019	4.77% medium-term notes	$400
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
Enbridge Pipelines (Southern Lights) L.L.C.			
Repayment			
	June 2019	3.98% medium-term notes due 2040	US$23
Enbridge Southern Lights LP			
Repayment			
	July 2019	4.01% senior notes due 2040	$10
Westcoast Energy Inc.			
Repayment			
	January 2019	5.60% medium-term notes	$250
	January 2019	5.60% medium-term notes	$50
	May 2019	6.90% senior secured notes due 2019	$13
	May 2019	4.34% senior secured notes due 2019	$2

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 September 30, 2019, our debt capitalization ratio was 47.9%, compared with 46.8% as at December 31, 2018.

There are no material restrictions on our cash. Total restricted cash of $57 million, as reported in the Consolidated Statements of Financial Position, primarily 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 September 30, 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 September 30, 2019 and December 31, 2018, our net available liquidity totaled $7,223 million and $9,409 million, respectively.

SOURCES AND USES OF CASH

	Nine months ended September 30,	
	2019	2018
(millions of Canadian dollars)		
Operating activities	**7,405**	7,999
Investing activities	**(5,029)**	(3,072)
Financing activities	**(2,124)**	(4,811)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(17)**	23
Increase in cash and cash equivalents and restricted cash	**235**	139

Significant sources and uses of cash for the nine months ended September 30, 2019 and September 30, 2018 are summarized below:

Operating Activities

- The decrease in cash flow provided by operations during the nine months ended September 30, 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 our business 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 nine months ended September 30, 2019 was attributable to activity in 2018 that was not present in 2019, primarily relating to a distribution received in the second quarter of 2018 from Sabal Trail Transmission, LLC (Sabal Trail) as a partial return of capital for construction and development costs previously funded by Sabal Trail's partners. In addition, in the third quarter of 2018, we received proceeds from asset dispositions from our sale of MOLP and international renewable assets.

- The factors above were partially offset by lower additions to intangible assets during the nine months ended September 30, 2019 compared with the same period in 2018, primarily due to the wind down of the Ontario Cap and Trade program in the fourth quarter of 2018.
- 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 nine months ended September 30, 2019 was primarily attributable to a net increase in commercial paper and credit facility draws and lower repayments of maturing long-term debt, partially offset by a decrease of long-term debt issued in 2019 when compared with the same period in 2018.
- The decrease in cash used in financing activities in 2019 was also attributable to activity in 2018 that was not present in 2019, primarily relating to proceeds from the sale of a portion of our interest in our Canadian and U.S. renewable assets to the CPPIB in the third quarter of 2018.
- Our common share dividend payments increased period-over-period 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 the first quarter of 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 of 2018.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

DCP Midstream, LP Definitive Agreement and Equity Restructuring

On November 6, 2019 DCP Midstream, LP (DCP MLP) announced the execution of a definitive agreement with its general partner, in which we indirectly own a 50% equity interest, and the concurrent closing of an equity restructuring transaction. The transaction resulted in the general partner converting all of its incentive distribution rights in DCP MLP, which were eliminated, and its 2% economic general partner interest in DCP MLP, while retaining a non-economic general partner interest, into newly-issued DCP MLP common units. As a result of this transaction, we increased our indirect ownership of outstanding DCP MLP common units from approximately 18% to approximately 28%, while retaining our indirect 50% ownership interest in the general partner of DCP MLP.

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, seeking damages in excess of US$140 million. On September 7, 2018, the United States District Court for the Eastern District of Pennsylvania granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants (the Amended Complaint). Eddystone Rail’s chances of success on its Amended Complaint cannot be predicted at this time. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US$32 million. The defendants’ chances of success on their counterclaims cannot be predicted at this time.

Dakota Access Pipeline
In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the United States Court for the District of Columbia contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline. The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corps permit and environmental review process. In August 2018, in response to a Court order to reconsider components of its environmental analysis, the Army Corps issued its decision that no supplemental environmental analysis was required. All four Tribes have since amended their complaints to include claims challenging the adequacy of the Army Corps' supplemental environmental analysis. According to the United States Court for the District of Columbia's schedule, the filing of summary judgment briefs on the merit of the plaintiff's claims challenging the adequacy of the Army Corps' remand process will proceed throughout the remainder of the year.

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 (the Tunnel Project). On December 19, 2018, we entered into a Tunnel Project agreement with the Government of Michigan. On March 28, 2019, the Michigan Attorney General issued an opinion finding the Michigan law PA 359 unconstitutional and soon after, Michigan Governor Whitmer issued a directive to Michigan agencies to cease any action implementing the statute.

To resolve the legal uncertainty created by the Michigan Attorney General's opinion and the directive issued by Michigan Governor Whitmer, on June 6, 2019, we filed a complaint with the Michigan Court of Claims to establish the constitutional validity of Michigan law PA 359 and enforceability of various agreements entered into between us and the State of Michigan related to the construction of the Tunnel Project. On June 11, 2019, State officials confirmed that we had valid permits to conduct specified geotechnical work which is ongoing and necessary to prepare for Tunnel Project construction. On June 27, 2019, the Michigan Attorney General requested the Michigan Court of Claims to dismiss our complaint and we opposed her request with our response filed on August 1, 2019. On October 31, 2019, the Michigan Court of Claims determined that Michigan law PA 359 is valid and is not unconstitutional. The Michigan Attorney General has filed an appeal of this decision.

On June 27, 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court that requests the Court to declare the easement that we have for the operation of the dual pipelines in the Straits to be invalid and to prohibit continued operation of the dual pipelines in the Straits "as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties". We continue to vigorously defend this action and on September 16, 2019, we filed our motion for summary disposition and requested dismissal of the State's Complaint in its entirety. On that same date, the State filed a motion for partial summary disposition and judgment in its favor on its claim that the easement was void from inception. The parties are now responding to the motions for summary disposition and briefing will be completed by December 10, 2019.

Line 5 Easement
For over six years, we have been in negotiations and discussions with the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) to resolve the Band's concerns over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. These negotiations and discussions did not resolve the Band's concerns. On July 23, 2019, the Band filed a complaint in the United States District Court for the Western District of Wisconsin alleging that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and also alleging that the pipeline is in trespass on certain tracts of land in which the Band possesses undivided ownership interests. The Band also seeks an order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. On September 24, 2019, in response to the Band's complaint, we filed an answer, defenses, and counterclaims against the Band, as well as a motion to dismiss with respect to Enbridge Inc. and EEP. On October 15, 2019, the Band filed its first amended complaint against us, adding new assertions about allegedly unsafe conditions at a specific location of the pipeline on the Reservation and requesting a declaration by the court that the Band has regulatory authority over Line 5. On October 29, 2019, we filed our response, defenses and counterclaims to the Band's first amended complaint. A trial date has been set for July 2021.

The Band has not sought a temporary injunction to immediately discontinue operation of Line 5. However, if successful, the Band's lawsuit could impact our ability to operate the pipeline on the Reservation. We have been vigorously defending the Band's action since it was filed and will continue to do so. Nevertheless, we also plan to continue working with the Band in an effort to address its concerns, and at the same time, as a contingency measure, we have begun taking steps to enable the construction of a reroute of Line 5 around the Reservation.

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. 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 $2.3 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. 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 Exchange Act is recorded, processed, summarized and reported within the time periods specified by the U.S. Securities and Exchange Commission'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 September 30, 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 U.S. Securities and Exchange Commission 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 September 30, 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* and *Growth Projects - Regulatory Matters* 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

On November 7, 2019, Guy Jarvis, Executive Vice President, Liquids Pipelines notified us of his intention to retire effective February 28, 2020. Effective January 1, 2020, Vern Yu, currently President and Chief Operating Officer, Liquids Pipelines will assume the role of Executive Vice President, Liquids Pipelines.

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.

Exhibit No.	Description
2.1	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)
2.2	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)
2.3	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)
2.4	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)
2.5	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)
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL document (included in Exhibit 101)

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:	November 8, 2019	By:	/s/ Al Monaco
			Al Monaco President and Chief Executive Officer
Date:	November 8, 2019	By:	/s/ Colin K. Gruending
			Colin K. Gruending Executive Vice President and Chief Financial Officer (Principal Financial Officer)

ENBRIDGE®
Life Takes Energy®

200, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8

Telephone: 403-231-3900
Facsimile: 403-231-3920
Toll free: 800-481-2804

enbridge.com