KINDER MORGAN, INC.
Form 10-Q
April 24, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

F O R M 10-Q

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

For the quarterly period ended March 31, 2018

or

o 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: 001-35081

KINDER MORGAN, INC.
(Exact name of registrant as specified in its charter)

Delaware	80-0682103
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1001 Louisiana Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)
Registrant's telephone number, including area code: 713-369-9000

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes þ No o

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. (Check one):
Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o Emerging Growth Company o

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. o

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

As of April 20, 2018, the registrant had 2,206,071,454 Class P shares outstanding.

KINDER MORGAN, INC. AND SUBSIDIARIES
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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

CIG	= Colorado Interstate Gas Company, L.L.C.	KMI	= Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries
EIG	= EIG Global Energy Partners		
ELC	= Elba Liquefaction Company, L.L.C.	KML	= Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries
EPB	= El Paso Pipeline Partners, L.P. and its majority-owned and/or controlled subsidiaries	KMLT	= Kinder Morgan Liquid Terminals, LLC
EPNG	= El Paso Natural Gas Company, L.L.C.	KMP	= Kinder Morgan Energy Partners, L.P. and its majority-owned and/or controlled subsidiaries
Hiland	= Hiland Partners, LP		
KMBT	= Kinder Morgan Bulk Terminals, Inc.	SFPP	= SFPP, L.P.
KMEP	= Kinder Morgan Energy Partners, L.P.	SNG	= Southern Natural Gas Company, L.L.C.
KMGP	= Kinder Morgan G.P., Inc.	TGP	= Tennessee Gas Pipeline Company, L.L.C.
		TMEP	= Trans Mountain Expansion Project

Unless the context otherwise requires, references to “we,” “us,” “our,” or “the company” are intended to mean Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries.

Common Industry and Other Terms

2017 Tax Reform	= The Tax Cuts & Jobs Act of 2017	EPA	= United States Environmental Protection Agency
		FASB	= Financial Accounting Standards Board
/d	= per day	FERC	= Federal Energy Regulatory Commission
BBtu	= billion British Thermal Units	GAAP	= United States Generally Accepted Accounting Principles
Bcf	= billion cubic feet		
CERCLA	= Comprehensive Environmental Response, Compensation and Liability Act	IPO	= Initial Public Offering
		LLC	= limited liability company
C$	= Canadian dollars	MBbl	= thousand barrels
CO_2	= carbon dioxide or our CO_2 business segment	MMBbl	= million barrels
DCF	= distributable cash flow	NGL	= natural gas liquids
DD&A	= depreciation, depletion and amortization	U.S.	= United States of America
EBDA	= earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments		

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “position,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

See “Information Regarding Forward-Looking Statements” and Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2017 (2017 Form 10-K) for a more detailed description of factors that may affect the forward-looking statements. You should keep these risk factors in mind when considering forward-looking statements. These risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. Because of these risks and uncertainties, you should not place undue reliance on any forward-looking statement. We plan to provide updates to projections included in this report when we believe previously disclosed projections no longer have a reasonable basis.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions, Except Per Share Amounts)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Revenues		
Natural gas sales	$827	$809
Services	1,967	1,977
Product sales and other	624	638
Total Revenues	3,418	3,424
Operating Costs, Expenses and Other		
Costs of sales	1,019	1,061
Operations and maintenance	619	533
Depreciation, depletion and amortization	570	558
General and administrative	173	184
Taxes, other than income taxes	88	104
Other expense, net	—	7
Total Operating Costs, Expenses and Other	2,469	2,447
Operating Income	949	977
Other Income (Expense)		
Earnings from equity investments	220	175
Amortization of excess cost of equity investments	(32)	(15)
Interest, net	(467)	(465)
Other, net	36	19
Total Other Expense	(243)	(286)
Income Before Income Taxes	706	691
Income Tax Expense	(164)	(246)
Net Income	542	445
Net Income Attributable to Noncontrolling Interests	(18)	(5)
Net Income Attributable to Kinder Morgan, Inc.	524	440
Preferred Stock Dividends	(39)	(39)
Net Income Available to Common Stockholders	$485	$401

Class P Shares		
Basic and Diluted Earnings Per Common Share	$0.22	$0.18
Basic and Diluted Weighted Average Common Shares Outstanding	2,207	2,230
Dividends Per Common Share Declared for the Period	$0.20	$0.125

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Net income	$542	$445
Other comprehensive income (loss), net of tax		
Change in fair value of hedge derivatives (net of tax expense of $(11) and $(39), respectively)	34	70
Reclassification of change in fair value of derivatives to net income (net of tax benefit of $5 and $12, respectively)	(16)	(21)
Foreign currency translation adjustments (net of tax benefit (expense) of $12 and $(7), respectively)	(65)	13
Benefit plan adjustments (net of tax expense of $(2) and $(5), respectively)	6	6
Total other comprehensive (loss) income	(41)	68
Comprehensive income	501	513
Comprehensive loss (income) attributable to noncontrolling interests	6	(5)
Comprehensive income attributable to Kinder Morgan, Inc.	$507	$508

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions, Except Share and Per Share Amounts)

	March 31, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 294	$ 264
Restricted deposits	69	62
Accounts receivable, net	1,349	1,448
Fair value of derivative contracts	94	114
Inventories	442	424
Income tax receivable	163	165
Other current assets	217	238
Total current assets	2,628	2,715
Property, plant and equipment, net	40,333	40,155
Investments	7,420	7,298
Goodwill	22,157	22,162
Other intangibles, net	3,044	3,099
Deferred income taxes	1,886	2,044
Deferred charges and other assets	1,543	1,582
Total Assets	$ 79,011	$ 79,055
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of debt	$ 2,494	$ 2,828
Accounts payable	1,221	1,340
Accrued interest	409	621
Accrued contingencies	307	291
Other current liabilities	998	1,101
Total current liabilities	5,429	6,181
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	34,723	33,988
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	720	927
Total long-term debt	35,543	35,015
Other long-term liabilities and deferred credits	2,381	2,735
Total long-term liabilities and deferred credits	37,924	37,750
Total Liabilities	43,353	43,931
Commitments and contingencies (Notes 1, 2 and 9)		
Redeemable Noncontrolling Interest	523	—
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,203,965,721 and 2,217,110,072 shares, respectively, issued and outstanding	22	22
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, 1,600,000 shares issued and outstanding	—	—

Additional paid-in capital	41,677	41,909
Retained deficit	(7,365)	(7,754)
Accumulated other comprehensive loss	(667)	(541)
Total Kinder Morgan, Inc.’s stockholders’ equity	33,667	33,636
Noncontrolling interests	1,468	1,488
Total Stockholders’ Equity	35,135	35,124
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders’ Equity	$ 79,011	$ 79,055

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)
(Unaudited)

	Three Months Ended March 31,	
	2018	2017
Cash Flows From Operating Activities		
Net income	$542	$445
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	570	558
Deferred income taxes	149	244
Amortization of excess cost of equity investments	32	15
Change in fair market value of derivative contracts	40	(6)
Earnings from equity investments	(220)	(175)
Distributions from equity investment earnings	127	102
Changes in components of working capital		
Accounts receivable, net	126	105
Inventories	(15)	(35)
Other current assets	4	10
Accounts payable	(140)	(35)
Accrued interest, net of interest rate swaps	(195)	(165)
Accrued contingencies and other current liabilities	(136)	(146)
Rate reparations, refunds and other litigation reserve adjustments	31	—
Other, net	59	(31)
Net Cash Provided by Operating Activities	974	886
Cash Flows From Investing Activities		
Acquisitions of assets and investments	(20)	(4)
Capital expenditures	(707)	(664)
Proceeds from sales of equity investments	33	—
Sales of property, plant and equipment, and other net assets, net of removal costs	1	71
Contributions to investments	(66)	(191)
Distributions from equity investments in excess of cumulative earnings	42	138
Loans to related party	(8)	—
Net Cash Used in Investing Activities	(725)	(650)
Cash Flows From Financing Activities		
Issuances of debt	6,039	1,517
Payments of debt	(5,684)	(2,122)
Debt issue costs	(21)	(1)
Cash dividends - common shares	(277)	(280)
Cash dividends - preferred shares	(39)	(39)
Repurchases of shares	(250)	—
Contributions from investment partner	38	391
Contributions from noncontrolling interests	3	6
Distributions to noncontrolling interests	(17)	(9)
Other, net	(1)	(1)
Net Cash Used in Financing Activities	(209)	(538)

Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	(3)	1
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	37	(301)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	$363	$486
Cash and Cash Equivalents, beginning of period	$264	$684
Restricted Deposits, beginning of period	62	103
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787
Cash and Cash Equivalents, end of period	294	396
Restricted Deposits, end of period	69	90
Cash, Cash Equivalents, and Restricted Deposits, end of period	363	486
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	$37	$(301)
Non-cash Investing and Financing Activities		
Increase in property, plant and equipment from both accruals and contractor retainage	$44	
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$657	$643
Cash paid (refund) during the period for income taxes, net	15	(2)

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Millions)
(Unaudited)

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2017	2,217	$ 22	2	$ —	$ 41,909	$ (7,754)	$ (541)	$ 33,636	$ 1,488	$ 35,124
Impact of adoption of ASUs (Note 1)						181	(109)	72		72
Balance at January 1, 2018	2,217	22	2	—	41,909	(7,573)	(650)	33,708	1,488	35,196
Repurchase of shares	(13)				(250)			(250)		(250)
Restricted shares					18			18		18
Net income						524		524	18	542
Distributions								—	(21)	(21)
Contributions								—	7	7
Preferred stock dividends						(39)		(39)		(39)
Common stock dividends						(277)		(277)		(277)
Other comprehensive income							(17)	(17)	(24)	(41)
Balance at March 31, 2018	2,204	$ 22	2	$ —	$ 41,677	$ (7,365)	$ (667)	$ 33,667	$ 1,468	$ 35,135

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2016	2,230	$ 22	2	$ —	$ 41,739	$ (6,669)	$ (661)	$ 34,431	$ 371	$ 34,802
Restricted shares					18			18		18
Net income						440		440	5	445
Distributions								—	(9)	(9)
Contributions								—	6	6
Preferred stock dividends						(39)		(39)		(39)
Common stock dividends						(280)		(280)		(280)
Impact of adoption of ASU 2016-09						8		8		8
Other					(1)			(1)	(13)	(14)
Other comprehensive income							68	68		68
Balance at March 31, 2017	2,230	$ 22	2	$ —	$ 41,756	$ (6,540)	$ (593)	$ 34,645	$ 360	$ 35,005

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

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KINDER MORGAN, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Organization

We are one of the largest energy infrastructure companies in North America. We own an interest in or operate approximately 85,000 miles of pipelines and 152 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store liquid commodities including petroleum products, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores. We are also a leading producer of CO_2, which we and others utilize for enhanced oil recovery projects primarily in the Permian basin.

Suspension of Non-Essential Spending on Trans Mountain Expansion Project

On April 8, 2018, KML announced that it was suspending all non-essential activities and related spending on the TMEP. KML also announced that under current circumstances, specifically including the continued actions in opposition to the TMEP by the Province of British Columbia (BC), it will not commit additional shareholder resources to the TMEP. However, KML further announced that it will consult with various stakeholders in an effort to reach agreements by May 31, 2018 that may allow the TMEP to proceed. KML stated it is difficult to conceive of any scenario in which it would proceed with the TMEP if an agreement is not reached by May 31, 2018. The focus in those consultations will be on two principles: clarity on the path forward, particularly with respect to the ability to construct through BC and adequate protection of KML shareholders.

KML had previously announced a “primarily permitting” strategy for the first half of 2018, focused on advancing the permitting process, rather than spending at full construction levels, until it obtained greater clarity on outstanding permits, approvals and judicial reviews. Rather than achieving greater clarity, the TMEP is now facing unquantifiable risk. Previously, opposition by BC was manifesting itself largely through BC’s participation in an ongoing judicial review. Unfortunately, BC has now been asserting broad jurisdiction and reiterating its intention to use that jurisdiction to stop the TMEP. On April 18, 2018, the Attorney General for BC announced that the Province will file a reference case by April 30, 2018, presenting a constitutional question to the BC Court of Appeal. The reference question has yet to be publicly disclosed; it is anticipated the question will seek to define the extent of BC’s constitutional jurisdiction, if any, to regulate marine or environmental risks, or the transport of certain petroleum products into BC. BC’s intention in that regard has been neither validated nor quashed, and BC has continued to threaten unspecified additional actions to prevent the TMEP success. Those actions have created even greater, and growing, uncertainty with respect to the regulatory landscape facing the TMEP. In addition, the parties still await judicial decisions on challenges to the original Order in Council and the BC Environmental Assessment Certificate approving the TMEP. These items, combined with the impending approach of critical construction windows, the lead-time required to ramp up spending, and the imperative that KML avoid incurring significant debt while lacking the necessary clarity, brought KML to the decision it announced on April 8, 2018. Given the current uncertain conditions, KML is not updating its cost and schedule estimate at this time. However, construction delays are likely to entail increased costs due to a variety of factors including extended personnel, equipment and facilities charges, storage charges for unused material and equipment, extended debt service, and inflation, among others.

In the event the TMEP is terminated, resulting impairments, foregone capitalized equity costs and potential wind down costs would have a significant effect on our results of operations. Potential impairments would be recognized primarily in the period in which the decision to terminate is made. As of March 31, 2018, C$1,135 million has been spent on development of the TMEP.

Basis of Presentation

General

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying unaudited consolidated financial statements have been prepared under the rules and regulations of the United States Securities and Exchange Commission (SEC). These rules and regulations conform to the accounting principles contained in the FASB’s Accounting Standards Codification, the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation.

In our opinion, all adjustments, which are of a normal and recurring nature, considered necessary for a fair statement of our financial position and operating results for the interim periods have been included in the accompanying consolidated financial statements, and certain amounts from prior periods have been reclassified to conform to the current presentation. Interim results are not necessarily indicative of results for a full year; accordingly, you should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2017 Form 10-K.

The accompanying unaudited consolidated financial statements include our accounts and the accounts of our subsidiaries over which we have control or are the primary beneficiary. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

Accounting Policy Changes

Adoption of New Accounting Pronouncements

On January 1, 2018, we adopted Accounting Standards Updates (ASU) No. 2014-09, "Revenue from Contracts with Customers" and a series of related accounting standard updates designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see Note 6.

On January 1, 2018, we retroactively adopted ASU No. 2016-18, "Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)." This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in a decrease of $13 million in "Other, net" in Cash Flows from Investing Activities, an increase of $103 million in "Cash, Cash Equivalents, and Restricted Deposits, beginning of the period," and an increase of $90 million in "Cash, Cash Equivalents, and Restricted Deposits, end of period" in our accompanying consolidated statement of cash flows for the three months ended March 31, 2017 from what was previously presented in our Quarterly Report on Form 10-Q for the three months ended March 31, 2017.
Amounts included in the restricted deposits in the accompanying consolidated financial statements represent a combination of restricted cash amounts required to be set aside by regulatory agencies to cover obligations for our captive and other insurance subsidiaries, and cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions.

On January 1, 2018, we adopted ASU No. 2017-05, "Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets." This ASU clarifies the scope and application of ASC 610-20 on contracts for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. This ASU also clarifies that the derecognition of all businesses is in the scope of ASC 810 and defines an "in substance nonfinancial asset." We utilized the modified retrospective method to adopt the provisions of this ASU, which required us to apply the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) to contracts that were not completed contracts as of January 1, 2018 through a cumulative adjustment to our "Retained deficit" balance. The cumulative effect of the adoption of this ASU was a $72 million, net of income taxes, adjustment to our "Retained deficit" balance as presented in our consolidated statement of stockholders' equity for the three months ended March 31, 2018. This ASU also requires us to classify EIG's cumulative contribution to ELC as mezzanine equity, which we have included as "Redeemable noncontrolling interest" on our consolidated balance sheet as of March 31, 2018, as EIG has the right under certain conditions to redeem their interests for cash. The December 31, 2017 balance of $485 million is included in "Other long-term liabilities and deferred credits" on our consolidated balance sheet as of December 31, 2017.

On January 1, 2018, we adopted ASU No. 2017-07, “Compensation - Retirement Benefits (Topic 715).” This ASU requires an employer to disaggregate the service cost component from the other components of net benefit cost, allows only the service cost component of net benefit cost to be eligible for capitalization and establishes how to present the service cost component and the other components of net benefit cost in the income statement. Topic 715 required us to retrospectively reclassify $3 million of other components of net benefit credits (excluding the service cost component) from “General and administrative” to “Other, net” in our accompany consolidated statement of income for the three months ended March 31, 2017. We prospectively applied Topic 715 related to net benefit costs eligible for capitalization.

On January 1, 2018, we adopted ASU No. 2018-02, “Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.” This ASU permits companies to reclassify the income tax effects of the 2017 Tax Reform on items within accumulated other comprehensive income to retained earnings. The FASB refers to these amounts as "stranded tax effects." Only the stranded tax effects resulting from the 2017 Tax Reform are eligible for reclassification. The adoption of this ASU resulted in a $109 million reclassification adjustment of stranded income effects from "Accumulated other comprehensive loss" to "Retained deficit" on our consolidated statement of stockholders' equity for the three months ended March 31, 2018.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P shares and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be restricted stock or restricted stock units issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of net income available to shareholders of Class P shares and participating securities (in millions):

	Three Months Ended March 31,	
	2018	2017
Net Income Available to Common Stockholders	$485	$401
Participating securities:		
Less: Net Income Allocated to Restricted stock awards(a)	(2)	(2)
Net Income Allocated to Class P Stockholders	$483	$399
Basic Weighted Average Common Shares Outstanding	2,207	2,230
Basic Earnings Per Common Share	$0.22	$0.18

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(a) As of March 31, 2018, there were approximately 10 million restricted stock awards outstanding.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share (in millions on a weighted-average basis):

	Three Months Ended March 31,	
	2018	2017
Unvested restricted stock awards	10	9
Warrants to purchase our Class P shares(a)	—	293
Convertible trust preferred securities	3	8
Mandatory convertible preferred stock(b)	58	58

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(a) On May 25, 2017, approximately 293 million unexercised warrants expired without the issuance of Class P common stock. Prior to expiration, each warrant entitled the holder to purchase one share of our common stock for an exercise price of $40 per share. The potential dilutive effect of the warrants did not consider the assumed proceeds to KMI upon exercise.

(b) Until our mandatory convertible preferred shares are converted to common shares, on or before the expected mandatory conversion date of October 26, 2018, the holder of each preferred share participates in our earnings by receiving preferred stock dividends.

2. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our accompanying consolidated statements of income.

The following table provides detail on the principal amount of our outstanding debt balances. The table amounts exclude all debt fair value adjustments, including debt discounts, premiums and issuance costs (in millions):

	March 31, 2018	December 31, 2017
Senior note, floating rate, due January 15, 2023	$ 250	$ 250
Senior notes, 1.50% through 8.05%, due 2018 through 2098(a)	15,093	13,136
Credit facility due November 26, 2019	275	125
Commercial paper borrowings	210	240
KML Credit Facility(b)	78	—
KMP senior notes, 2.65% through 9.00%, due 2018 through 2044(c)	17,910	18,885
TGP senior notes, 7.00% through 8.375%, due 2027 through 2037	1,240	1,240
EPNG senior notes, 7.50% through 8.625%, due 2022 through 2032	760	760
CIG senior notes, 4.15% and 6.85%, due 2026 and 2037	475	475
Kinder Morgan Finance Company, LLC, senior notes, 6.00% and 6.40%, due 2018 and 2036(d)	36	786
EPC Building, LLC, promissory note, 3.967%, due 2018 through 2035	418	421
Trust I preferred securities, 4.75%, due March 31, 2028	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock	100	100
Other miscellaneous debt	251	277
Total debt – KMI and Subsidiaries	37,317	36,916
Less: Current portion of debt(e)	2,494	2,828
Total long-term debt – KMI and Subsidiaries(f)	$ 34,823	$ 34,088

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(a) Amounts include senior notes that are denominated in Euros and have been converted to U.S. dollars and are respectively reported above at the March 31, 2018 exchange rate of 1.2324 U.S. dollars per Euro and the December 31, 2017 exchange rate of 1.2005 U.S. dollars per Euro. For the three months ended March 31, 2018, our debt balance increased by $39 million as a result of the change in the exchange rate of U.S. dollars per Euro. The increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in “Deferred charges and other assets” and “Other long-term liabilities and deferred credits” on our consolidated balance sheets. At the time of issuance, we entered into cross-currency swap agreements associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 4 “Risk Management—Foreign Currency Risk Management”). In February 2018, we repaid $82 million of maturing 7.00% senior notes. On March 1, 2018, we issued $1,250 million of 4.30% fixed rate and $750 million of 5.20%, fixed rate unsecured senior notes due March 1, 2028 and March 1, 2048, respectively. The net proceeds from the notes were used primarily to repay our commercial paper and borrowings under our revolving credit facility that largely resulted from the repayment of KMP senior notes in the first quarter of 2018. See (c) and (d) below. Interest on both series of notes is payable semi-annually in arrears on March 1 and September 1 of each year, beginning on September 1, 2018. We may redeem all or a part of these notes at any time at the redemption prices plus accrued interest.

(b) The KML credit facility is denominated in C$ and has been converted to U.S. dollars and reported above at the March 31, 2018 exchange rate of 0.7756 U.S. dollars per C$. See “—Credit Facilities” below.

(c) In February 2018, we repaid $975 million of maturing 5.95% senior notes.

(d) In January 2018, we repaid $750 million of maturing 6.00% Kinder Morgan Finance Company, LLC senior notes.

(e) Amounts include KMI and KML outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months (see “—Current Portion of Debt” below).

(f) Excludes our “Debt fair value adjustments” which, as of March 31, 2018 and December 31, 2017, increased our combined debt balances by $720 million and $927 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements.

We and substantially all of our wholly owned domestic subsidiaries are a party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Also, see Note 11.

Credit Facilities

KMI

As of March 31, 2018, we had $275 million outstanding under our credit facility, $210 million outstanding under our commercial paper program and $99 million in letters of credit. Our availability under our $5 billion credit facility as of March 31, 2018 was $4,416 million. As of March 31, 2018, we were in compliance with all required covenants.

KML

As of March 31, 2018, KML had C$447 million available under its five year C$500 million working capital facility (after reducing the capacity for the C$53 million (U.S.$41 million) in letters of credit), C$100.0 million (U.S.$78 million) outstanding under its C$4.0 billion construction facility and no amounts outstanding under its C$1.0 billion revolving contingent credit facility. As of March 31, 2018, KML was in compliance with all required covenants.

Current Portion of Debt

Our current portion of debt as of March 31, 2018, primarily includes the above credit facilities and commercial paper borrowings and the following significant series of long-term notes maturing within the next 12 months:

Senior notes - $477 million 7.25% notes due June 1, 2018
Senior notes - $500 million 9.00% notes due February 1, 2019
Senior notes - $800 million 2.65% notes due February 1, 2019

3. Stockholders' Equity

Common Equity

As of March 31, 2018, our common equity consisted of our Class P common stock. For additional information regarding our Class P common stock, see Note 11 to our consolidated financial statements included in our 2017 Form 10-K.

On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. During the three months ended March 31, 2018, we repurchased approximately 13 million of our Class P shares for approximately $250 million.

KMI Common Stock Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. The following table provides information about our per share dividends:

	Three Months Ended March 31,	
	2018	2017
Per common share cash dividend declared for the period	$0.20	$0.125
Per common share cash dividend paid in the period	$0.125	$0.125

On April 18, 2018, our board of directors declared a cash dividend of $0.20 per common share for the quarterly period ended March 31, 2018, which is payable on May 15, 2018 to common shareholders of record as of the close of business on April 30, 2018.

Mandatory Convertible Preferred Stock

We have issued and outstanding 1,600,000 shares of 9.750% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share that, unless converted earlier at the option of the holders, will automatically convert into common stock on October 26, 2018. For additional information regarding our mandatory convertible preferred stock, see Note 11 to our consolidated financial statements included in our 2017 Form 10-K.

Preferred Stock Dividends

On January 17, 2018, our board of directors declared a cash dividend of $24.375 per share of our mandatory convertible preferred stock (equivalent of $1.21875 per depositary share) for the period from and including January 26, 2018 through and including April 25, 2018, which is payable on April 26, 2018 to mandatory convertible preferred shareholders of record as of the close of business on April 11, 2018.

Noncontrolling Interests

KML Distributions

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its DCF. For additional information regarding our KML distributions, see Note 11 to our consolidated financial statements included in our 2017 Form 10-K.

The following table provides information regarding KML distributions to our noncontrolling interests (in millions except per share and share distribution amounts):

	Three Months Ended March 31, 2018		
	Shares	U.S.$	C$
KML Restricted Voting Shares			
Per restricted voting share declared for the period			$0.1625
Per restricted voting share paid in the period		$0.1291	$0.1625
Total value of distributions paid in the period		13	17
Cash distributions paid in the period to the public		9	12
Share distributions paid in the period to the public under KML's DRIP	294,397		
KML Series 1 Preferred Shares			
Per Series 1 Preferred Share paid in the period		$0.2607	$0.328125
Cash distributions paid in the period to the public		3	4
KML Series 3 Preferred Shares			
Per Series 3 Preferred Share paid in the period		$0.1754	$0.22082
Cash distributions paid in the period to the public		2	2

On April 18, 2018, KML's board of directors declared a cash dividend of C$0.328125 per share of its Series 1 Preferred Shares for the period from and including February 15, 2018 through and including May 14, 2018, which is payable on May 15, 2018 to Series 1 Preferred Shareholders of record as of the close of business on April 30, 2018.

On April 18, 2018, KML's board of directors declared a cash dividend of C$0.325 per share of its Series 3 Preferred Shares for the period from and including February 15, 2018 through and including May 14, 2018, which is payable on May 15, 2018 to Series 3 Preferred Shareholders of record as of the close of business on April 30, 2018.

4. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to some of these risks.

Energy Commodity Price Risk Management

As of March 31, 2018, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(21.4)	MMBbl
Crude oil basis	(6.2)	MMBbl
Natural gas fixed price	(57.4)	Bcf
Natural gas basis	(47.1)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(1.6)	MMBbl
Crude oil basis	(0.3)	MMBbl
Natural gas fixed price	(3.1)	Bcf
Natural gas basis	(1.4)	Bcf
NGL fixed price	(3.7)	MMBbl

As of March 31, 2018, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2022.

Interest Rate Risk Management

As of March 31, 2018 and December 31, 2017, we had a combined notional principal amount of $10,575 million and $9,575 million, respectively, of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of London Interbank Offered Rate plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of March 31, 2018, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

As of both March 31, 2018 and December 31, 2017, we had a combined notional principal amount of $1,358 million of cross-currency swap agreements to manage the foreign currency risk related to our Euro denominated senior notes by effectively converting all of the fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		March 31, 2018	December 31, 2017	March 31, 2018	December 31, 2017
	Location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$51	$ 65	$(76)	$ (53)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	8	14	(33)	(24)
Subtotal		59	79	(109)	(77)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	33	41	(15)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	105	164	(156)	(62)
Subtotal		138	205	(171)	(65)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(26)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	251	166	—	—
Subtotal		251	166	(26)	(6)
Total		448	450	(306)	(148)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	10	8	(18)	(22)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	(2)	(2)
Total		10	8	(20)	(24)
Total derivatives		$458	$ 458	$(326)	$ (172)

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Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of our derivative contracts in our accompanying consolidated statements of income (in millions):

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item Three Months Ended March 31,	
		2018	2017
Interest rate swap agreements	Interest, net	$(173)	$(39)
Hedged fixed rate debt	Interest, net	$168	$36

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)(a)		Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)		Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2018	2017		2018	2017		2018	2017
Energy commodity derivative contracts	$(17)	$68	Revenues—Natural gas sales	$ —	$ 2	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	(14)	6	Revenues—Product sales and other	(29)	3
			Costs of sales	—	3	Costs of sales	—	—
Interest rate swap agreements(c)	1	—	Earnings from equity investments	(1)	—	Earnings from equity investments	—	—
Cross-currency swap	50	2	Other, net	31	10	Other, net	—	—
Total	$34	$70	Total	$ 16	$ 21	Total	$ (29)	$ 3

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(a) We expect to reclassify an approximate $21 million loss associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of March 31, 2018 into earnings during the next twelve months (when the associated forecasted transactions are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) Amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

(c) Amounts represent our share of an equity investee's accumulated other comprehensive loss.

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives Three Months Ended March 31,	
		2018	2017
Energy commodity derivative contracts	Revenues—Natural gas sales	$ 3	$ 6
	Revenues—Product sales and other	(1)	12
Total(a)		$ 2	$ 18

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(a) The three months ended March 31, 2018 and 2017 include approximate gains of $8 million and $12 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of March 31, 2018 and December 31, 2017, we had no outstanding letters of credit supporting our commodity price risk management program. As of March 31, 2018 and December 31, 2017, we had cash margins of $11 million and $1 million, respectively, posted by us with our counterparties as collateral and reported within “Restricted deposits” on our accompanying consolidated balance sheets. The balance at

March 31, 2018 consisted of initial margin requirements of $10 million and variation margin requirements of $1 million. We also use industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of March 31, 2018, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one notch we would be required to post $43 million of additional collateral and no additional collateral beyond this $43 million if we were downgraded two notches.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss

Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as “Accumulated other comprehensive loss” within “Stockholders’ Equity” in our consolidated balance sheets. Changes in the components of our “Accumulated other comprehensive loss” not including non-controlling interests are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total accumulated other comprehensive loss
Balance as of December 31, 2017	$ (27)	$ (189)	$ (325)	$ (541)
Other comprehensive gain (loss) before reclassifications	34	(41)	6	(1)
Gains reclassified from accumulated other comprehensive loss	(16)	—	—	(16)
Impact of adoption of ASU 2018-02 (Note 1)	(4)	(36)	(69)	(109)
Net current-period other comprehensive income (loss)	14	(77)	(63)	(126)
Balance as of March 31, 2018	$ (13)	$ (266)	$ (388)	$ (667)

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total accumulated other comprehensive loss
Balance as of December 31, 2016	$ (1)	$ (288)	$ (372)	$ (661)
Other comprehensive gain before reclassifications	70	13	6	89
Gains reclassified from accumulated other comprehensive loss	(21)	—	—	(21)
Net current-period other comprehensive income	49	13	6	68
Balance as of March 31, 2017	$ 48	$ (275)	$ (366)	$ (593)

5. Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; (ii) interest rate swap agreements; and (iii) cross-currency swap agreements, based on the three levels established by the Codification (in millions). The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of March 31, 2018							
Energy commodity derivative contracts(a)	$5	$64	$ —	$ 69	$(40)	$ —	$ 29
Interest rate swap agreements	—	138	—	138	(8)	—	130
Cross-currency swap agreements	—	251	—	251	(26)	—	225
As of December 31, 2017							
Energy commodity derivative contracts(a)	$17	$70	$ —	$ 87	$(42)	$ (12)	$ 33
Interest rate swap agreements	—	205	—	205	(15)	—	190
Cross-currency swap agreements	$—	$166	$ —	$ 166	$(6)	$ —	$ 160

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(b)	Net amount
As of March 31, 2018							
Energy commodity derivative contracts(a)	$(4)	$(125)	$ —	$(129)	$ 40	$ 1	$ (88)
Interest rate swap agreements	—	(171)	—	(171)	8	—	(163)
Cross-currency swap agreements	—	(26)	—	(26)	26	—	—
As of December 31, 2017							
Energy commodity derivative contracts(a)	$(3)	$(98)	$ —	$(101)	$ 42	$ —	$ (59)
Interest rate swap agreements	—	(65)	—	(65)	15	—	(50)
Cross-currency swap agreements	—	(6)	—	(6)	6	—	—

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(a) Level 1 consists primarily of New York Mercantile Exchange natural gas futures. Level 2 consists primarily of over-the-counter West Texas Intermediate swaps and options and NGL swaps.

(b)

Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amount associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances are disclosed below (in millions):

	March 31, 2018		December 31, 2017	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$38,037	$ 39,525	$37,843	$ 40,050

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We used Level 2 input values to measure the estimated fair value of our outstanding debt balances as of both March 31, 2018 and December 31, 2017.

6. Revenue Recognition
Adoption of Topic 606

Effective January 1, 2018, we adopted ASU No. 2014-09, “Revenue from Contracts with Customers” and the series of related accounting standard updates that followed (collectively referred to as “Topic 606”). We utilized the modified retrospective method to adopt Topic 606, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) revenue contracts which were not completed as of January 1, 2018. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 were not revised. The cumulative effect of this adoption of Topic 606 as of January 1, 2018 was not material.

The impact to our consolidated financial statement line items from the adoption of Topic 606 for these changes was as follows (in millions):

	Three Months Ended March 31, 2018		
Line Item	As Reported	Amounts Without Adoption of Topic 606	Effect of Change Increase/(Decrease)
Consolidated Statement of Income			
Natural gas sales	$827	$ 841	$ (14)
Services	1,967	2,012	(45)
Product sales and other	624	711	(87)
Total Revenues	3,418	3,564	(146)
Cost of sales	1,019	1,165	(146)
Operating Income	949	949	—

The effect-of-change amounts in the table above are attributable to our Natural Gas Pipelines - Non-Regulated reporting unit, which provides gathering, processing and processed commodity sales services for various producers.

In those instances where we purchase and obtain control of the entire natural gas stream in our producer arrangements, we have determined these are contracts with suppliers rather than contracts with customers and therefore, these arrangements are not included in the scope of Topic 606. These supplier arrangements are subject to updated guidance in ASC 705, Cost of Sales and Services, whereby any embedded fees within such contracts, which historically have been reported as Services revenue, are now reported as a reduction to Cost of sales upon adoption of Topic 606.

In our natural gas processing arrangements where we extract and sell the commodities derived from the processed natural gas stream (i.e., residue gas or NGLs), we may take control of: (i) none of the commodities we sell, (ii) a portion of the commodities we sell, or (iii) all of the commodities we sell.

In those instances where we remit all of the cash proceeds received from third parties for selling the extracted commodities, less the fees attributable to these arrangements, we have determined that the producer has control over these commodities. Upon adoption of Topic 606, we eliminated recording both sales revenue (Natural gas and Product) and Cost of sales amounts and now only record fees attributable to these arrangements to Service revenues.

In other instances where we do not obtain control of the extracted commodities we sell, we are acting as an agent for the producer and, upon adoption of Topic 606, we have continued to recognize Services revenue for the net amount of consideration we retain in exchange for our service.

When we purchase and obtain control of a portion of the residue gas or NGLs we sell, we have determined these arrangements contain both a supply and a service revenue element and therefore are partially in the scope of Topic 606. In these arrangements, the producer is a supplier for the cash settled portion of the commodity we purchase and a customer with regards to the service provided to gather and redeliver the other component. Upon adoption of Topic 606, fees attributable to the supply element are recorded as a reduction to Cost of sales and fees attributable to the service element are recorded as Services revenue. Previously, we recognized Services revenue for both elements.

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Topic 606. The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Our customer sales contracts primarily include natural gas sales, NGL sales, crude oil sales, CO_2 sales, and transmix sales contracts, as described below. Generally, for the majority of these contracts: (i) each unit (Mcf, gallon, barrel, etc.) of commodity product is a separate performance obligation, as our promise is to sell multiple distinct units of commodity product at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity product sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity product's standalone selling price and recognized as revenue upon delivery of the commodity product, which is the point in time when the customer obtains control of the commodity product and our performance obligation is satisfied.

Our customer services contracts primarily include transportation service, storage service, gathering and processing service, and terminaling service contracts, as described below. Generally, for the majority of these contracts: (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) method for measuring transfer of control of the services and progress towards satisfying our performance obligation, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- Contracts without Makeup Rights. If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of service are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as “breakage”), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service (e.g., reservation), continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

Contracts with Makeup Rights. If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Nature of Revenue by Segment

Natural Gas Pipelines Segment

We provide various types of natural gas transportation and storage services, natural gas and NGL sales contracts, and various types of gathering and processing services for producers, including receiving, compressing, transporting and re-delivering quantities of natural gas and/or NGLs made available to us by producers to a specified delivery location.

Natural Gas Transportation and Storage Contracts

The natural gas we receive under our transportation and storage contracts remains under the control of our customers. In many cases, generally described as firm service, the customer generally pays a two-part transaction price that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities up to contractually specified capacity levels (referred to as "reservation") and (ii) a per-unit rate for quantities of natural gas actually transported or injected into/withdrawn from storage. In our firm service contracts we generally promise to provide a single integrated service each day over the life of the contract, which is fundamentally a stand-ready obligation to provide services up to the customer's reservation capacity prescribed in the contract. Our customers have a take-or-pay payment obligation with respect to the fixed reservation fee component, regardless of the quantities they actually transport or store. In other cases, generally described as interruptible service, there is no fixed fee associated with these transportation and storage services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have firm service contracts. We do not have an obligation to perform under interruptible customer arrangements until we accept and schedule the customer's request for periodic service. The customer pays a transaction price based on a per-unit rate for the quantities actually transported or injected into/withdrawn from storage.

Natural Gas and NGL Sales Contracts

Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales. These customer contracts generally provide for the customer to nominate a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Gathering and Processing Contracts

We provide various types of gathering and processing services for producers, including receiving, processing, compressing, transporting and re-delivering quantities of natural gas made available to us by producers to a specified delivery location. This integrated service can be firm if subject to a minimum volume commitment or acreage dedication or non-firm when offered on an as requested, non-guaranteed basis. In our gathering contracts we generally promise to provide the contracted integrated services each day over the life of the contract. The customer pays a transaction price typically based on a per-unit rate for the quantities actually gathered and/or processed, including amounts attributable to deficiency quantities associated with minimum volume contracts.

CO_2 Segment

Our crude oil, NGL, CO_2 and natural gas production customer sales contracts typically include a specified quantity and quality of commodity product to be delivered and sold to the customer at a specified delivery point. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Liquids Tank Services

Firm Storage and Handling Contracts: We have liquids tank storage and handling service contracts that include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Firm Handling Contracts: For our firm handling service contracts, we typically promise to handle on a stand-ready basis throughput volumes up to the customer’s minimum volume commitment amount. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it used the handling service. The customer pays a transaction price typically based on a per-unit rate for volumes handled, including amounts attributable to deficiency quantities.

Bulk Services

Our bulk storage and handling contracts generally include inbound handling of our customers’ dry bulk material product (e.g. petcoke, metals, ores) into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. In some cases, the customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

Products Pipelines Segment

We provide crude oil and refined petroleum transportation and storage services on a firm or non-firm basis. For our firm transportation service, we typically promise to transport on a stand-ready basis the customer’s minimum volume commitment amount. The customer is obligated to pay for its volume commitment amount, regardless of whether or not it flows volumes into our pipeline. The customer pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities. Our firm storage service generally includes a fixed monthly fee for the portion of storage capacity reserved by the customer and a per-unit rate for actual quantities injected into/withdrawn from storage. The customer is obligated to pay the fixed monthly reservation fee, regardless of whether or not it uses our storage facility (i.e., take-or-pay payment obligation). Non-firm transportation and storage service is provided to our customers when and to the extent we determine the requested capacity is available in our pipeline system and/or terminal storage facility. The customer typically pays a per-unit rate for actual quantities of product injected into/withdrawn from storage and/or transported.

We sell transmix, crude oil or other commodity products. The customer's contracts generally include a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Kinder Morgan Canada Segment

We provide crude oil and refined petroleum transportation services generally as described above for non-firm, interruptible transportation services in our Products segment. The Trans Mountain pipeline system (TMPL) regulated tariff is designed to provide revenues sufficient to recover the costs of providing transportation services to shippers, including a return on invested capital. TMPL's revenue is adjusted according to terms prescribed in our toll settlement with shippers as approved by the National Energy Board (NEB). Differences between transportation revenue recognized pursuant to our toll settlement and actual toll receipts are recognized as regulatory assets or liabilities and are settled in future tolls.

Disaggregation of Revenues

The following table presents our revenues disaggregated by revenue source and type of revenue for each revenue source (in millions):

	Three Months Ended March 31, 2018						
	Natural Gas Pipelines	CO_2	Terminals	Products Pipelines	Kinder Morgan Canada	Corporate and Eliminations	Total
Revenues from contracts with customers							
Services							
Firm services(a)	$803	$1	$ 254	$ 138	$ —	$ (4)	$1,192
Fee-based services	203	17	144	183	64	1	612
Total services revenues	1,006	18	398	321	64	(3)	1,804
Sales							
Natural gas sales	826	—	—	—	—	(2)	824
Product sales	257	317	2	48	—	—	624
Other sales	2	—	—	—	—	—	2
Total sales revenues	1,085	317	2	48	—	(2)	1,450
Total revenues from contracts with customers	2,091	335	400	369	64	(5)	3,254
Other revenues(b)	75	(31)	93	30	(3)	—	164
Total revenues	$2,166	$304	$ 493	$ 399	$ 61	$ (5)	$3,418

(a) Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. In these arrangements, the customer is obligated to pay for the rendered service whether or not the customer chooses to utilize the service. Excludes service contracts with indexed-based pricing, which along with revenues from other customer service contracts are reported as Fee-based services.

(b) Amounts recognized as revenue under guidance prescribed in Topics of the Accounting Standards Codification other than in Topic 606 and primarily include leases and derivatives. See Note 4 for additional information related to our derivative contracts.

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition and our right to invoice the customer is conditioned on something other than the passage of time (e.g., breakage revenue associated with contracts with minimum volume commitment payment obligations, contracts where revenue levelization is appropriate). Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts, and (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires).

The following table presents the activity in our contract assets and liabilities for the three months ended March 31, 2018 (in millions):

Contract Assets(a)	
Balance at December 31, 2017	$32
Additions	24
Transfer to Accounts receivable	(21)
Balance at March 31, 2018	$35
Contract Liabilities(b)	
Balance at December 31, 2017	$206
Additions	110
Transfer to Revenues	(78)
Balance at March 31, 2018	$238

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(a) Includes current balances of $28 million and $25 million reported within “Other current assets” in our accompanying consolidated balance sheets at March 31, 2018 and December 31, 2017, respectively, and includes non-current balances of $7 million and $7 million reported within “Deferred charges and other assets” in our accompanying consolidated balance sheets at March 31, 2018 and December 31, 2017, respectively.

(b) Includes current balances of $88 million and $79 million reported within “Other current liabilities” in our accompanying consolidated balance sheets at March 31, 2018 and December 31, 2017, respectively, and includes non-current balances of $150 million and $127 million reported within “Other long-term liabilities and deferred credits” in our accompanying consolidated balance sheets at March 31, 2018 and December 31, 2017, respectively.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our “contractually committed” revenue as of March 31, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods (in millions):

Year	Estimated Revenue
Nine months ended December 31, 2018	$ 3,630
2019	4,102
2020	3,442
2021	2,997
2022	2,511
Thereafter	13,473
Total	$ 30,155

Our contractually committed revenue, for purposes of the tabular presentation above, is generally limited to service or commodity sale customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedients that we elected to apply, remaining performance obligations for: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue at the amount for which we have the right to invoice for services performed.

7. Reportable Segments

Financial information by segment follows (in millions):

	Three Months Ended March 31, 2018	2017
Revenues		
Natural Gas Pipelines		
Revenues from external customers	$2,164	$2,168
Intersegment revenues	2	3
CO_2	304	303
Terminals		
Revenues from external customers	493	487
Intersegment revenues	—	—
Products Pipelines		
Revenues from external customers	396	398
Intersegment revenues	3	4
Kinder Morgan Canada	61	59
Corporate and intersegment eliminations(a)	(5)	2
Total consolidated revenues	$3,418	$3,424

	Three Months Ended March 31, 2018	2017
Segment EBDA(b)		
Natural Gas Pipelines	$1,136	$1,055
CO_2	199	218
Terminals	295	307
Products Pipelines	259	287
Kinder Morgan Canada	46	43
Total Segment EBDA	1,935	1,910
DD&A	(570)	(558)
Amortization of excess cost of equity investments	(32)	(15)
General and administrative and corporate charges	(160)	(181)
Interest, net	(467)	(465)
Income tax expense	(164)	(246)
Total consolidated net income	$542	$445

	March 31, 2018	December 31, 2017
Assets		
Natural Gas Pipelines	$51,224	$ 51,173
CO_2	3,938	3,946
Terminals	9,876	9,935
Products Pipelines	8,564	8,539
Kinder Morgan Canada	2,178	2,080
Corporate assets(c)	3,231	3,382
Total consolidated assets	$79,011	$ 79,055

(a) 2017 includes a $9 million management fee for services we perform as operator of an equity investee.

(b)

Includes revenues, earnings from equity investments, other, net, less operating expenses, and other (income) expense, net.

(c) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy activity) not allocated to the reportable segments.

8. Income Taxes

Income tax expense included in our accompanying consolidated statements of income were as follows (in millions, except percentages):

	Three Months Ended March 31,	
	2018	2017
Income tax expense	$164	$246
Effective tax rate	23.2 %	35.6 %

The effective tax rate for the three months ended March 31, 2018 is higher than the statutory federal rate of 21% primarily due to state and foreign income taxes, partially offset by dividend-received deductions from our investment in Florida Gas Transmission Company (Citrus) and Plantation Pipe Line.

The effective tax rate for the three months ended March 31, 2017 is slightly higher than the statutory federal rate of 35% primarily due to state and foreign income taxes, partially offset by dividend-received deductions from our investment in Citrus and Plantation Pipe Line.

We continue to assess the impact of the Tax Cuts and Jobs Act of 2017 (2017 Tax Reform) on our business. Any adjustment to our provisional amounts recorded as of December 31, 2017 will be reported in the reporting period in which any such adjustments are determined and may be material in the period in which the adjustments are made. Earnings from equity investments on our statement of income for the three months ended March 31, 2018 was increased by $44 million ($34 million impact to us after income tax expense) for our share of certain equity investees' 2017 Tax Reform provisional adjustments. For additional information regarding the 2017 Tax Reform, see Note 5 to our consolidated financial statements included in our 2017 Form 10-K.

9. Litigation, Environmental and Other Contingencies

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or dividends to our shareholders. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material or, in the judgment of management, we conclude the matter should otherwise be disclosed.

FERC Proceedings

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers, the most recent of which was filed in 2015 (docketed at OR16-6) challenging SFPP's filed East Line rates. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP's index-based rate increases. If the shippers prevail on their arguments or claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing date of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. On March 22, 2016, the D.C. Circuit issued a decision in United Airlines, Inc. v. FERC remanding to FERC for further consideration of two issues: (1) the appropriate data to be used to determine the return on equity for SFPP in the underlying docket, and (2) the just and reasonable return to be provided to a tax pass-through entity that includes an income tax allowance in its underlying cost of service. On July 21, 2017, an initial decision by the Administrative Law Judge (ALJ) in OR16-6 concluded that the Complainants are due reparations, with appropriate interest, equal to the difference between what SFPP collected from the Complainants for service on the East Line and the amounts SFPP would have collected had it charged just and reasonable rates for that line. The ALJ ruled that an income tax allowance should be included in the cost of service both to determine reparations and to set going forward rates, and found that the new just and reasonable rates are not knowable until the FERC reviews the initial decision and orders a compliance filing. The FERC will determine which portions of the initial decision to affirm, reject or amend. On March 15, 2018, the FERC announced certain policy changes including a Revised Policy Statement on Treatment of Income Taxes and, that same day, the FERC issued orders in a series of pending SFPP proceedings which combined to deny income tax allowance to SFPP, direct SFPP to make compliance filings in its 2008 and 2009 rate filing documents, and restart the 2011 SFPP complaint proceeding which had been abated. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $40 million in annual rate reductions and approximately $300 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP's rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. EPNG sought federal appellate review of Opinion 517-A and oral arguments were held on February 15, 2017. On February 21, 2017, the reviewing court delayed the case until the FERC rules on the rehearing requests pending in the 2010 Rate Case. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates and required EPNG to file revised pro forma recalculated rates consistent with the terms of Opinions 517-A and 528-A. EPNG and two intervenors sought rehearing of certain aspects of the decision, and the judicial review sought by certain intervenors has been delayed until the FERC issues an order on rehearing. On February 23, 2018, a customer group filed a motion in the 2010 rate case requesting the FERC order us to recalculate the rates to be effective on January 1, 2018 to include impacts of the 2017 Tax Reform. We answered in opposition on March 12, 2018. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. With respect to the 2010 rate case, EPNG believes it has an appropriate reserve related to the findings in Opinions 517-A and 528-A.

TMEP Litigation

There are numerous legal challenges pending before the Federal Court of Appeal which have been filed by various governmental and non-governmental organizations, First Nations or other parties that seek judicial review of the recommendation of the NEB and subsequent decision by the Federal Governor in Council to conditionally approve the TMEP. The petitions allege, among other things, that additional consultation, engagement or accommodation is required and that various non-economic impacts of the TMEP were not adequately considered. The remedies sought include requests that the NEB recommendation be quashed, that additional consultations be undertaken, and that the order of the Governor in Council approving the TMEP be quashed. After provincial elections in British Columbia (BC) on May 9, 2017, the New Democratic Party and Green Party formed a majority government. The new BC government sought and was granted limited intervenor status in the Federal Court of Appeal proceedings to argue against the government's approval of the TMEP. A hearing was conducted by the Federal Court of Appeal from October 2 through October 13, 2017. A decision is expected in the coming months, and is subject to potential further appeal to the Supreme Court of Canada. Although we believe that each of the foregoing appeals lacks merit, in the event an applicant is successful at the Supreme Court of Canada, among other potential impacts, the NEB recommendation or Governor in Council's approval may be quashed, permits may be revoked, the TMEP may be subject to additional significant regulatory reviews, there may be significant changes to the TMEP plans, further obligations or restrictions may be implemented, or the TMEP may be stopped altogether, which could materially impact the overall feasibility or economic benefits of the TMEP, which in turn would have a material adverse effect on the TMEP and, consequently, our investment in KML.

In addition to the judicial reviews of the NEB recommendation report and Governor in Council's order, two judicial review proceedings have been commenced at the Supreme Court of BC (the Squamish Nation; and the City of Vancouver). The petitions allege a duty and failure to consult or accommodate First Nations, and generally, among other claims, that the Province ought not to have approved the TMEP. Each applicant seeks to quash the Environmental Assessment Certificate (EAC) that was issued by the BC Environmental Assessment Office. On September 29, 2017, the BC government filed evidence in support of the EAC in the judicial review proceeding involving the Squamish Nation. Hearings were conducted in October and November 2017, respectively, for the City of Vancouver and the Squamish Nation judicial review proceedings and the Court took the matters under consideration with decisions expected in the coming months. Although we believe that each of the foregoing appeals lacks merit, in the event that an applicant for judicial review is successful, among other potential impacts, the EAC may be quashed, provincial permits may be revoked, the TMEP may be subject to additional significant regulatory reviews, there may be significant changes to the TMEP plans, further obligations or restrictions may be imposed or the TMEP may be stopped altogether. In the event that an applicant is unsuccessful at the Supreme Court of BC, they may further seek to appeal the decision to the BC Court of Appeal. Any decision of the BC Court of Appeal may be appealed to the Supreme Court of Canada. A successful appeal at either of these levels could result in the same types of consequences described above.

On October 26, 2017 and November 14, 2017, Trans Mountain filed motions with the NEB. The first motion sought to resolve delays experienced by Trans Mountain in obtaining preliminary plan approvals from the City of Burnaby. The second motion sought to establish an NEB process to backstop provincial and municipal processes in a fair, transparent and expedited fashion. On December 7, 2017, the NEB issued an order granting the relief requested by Trans Mountain in respect of its motion related to Burnaby (the Burnaby Order). On January 19, 2018, the NEB granted, in part, Trans Mountain's second motion by establishing a generic process to hear any future motions as they relate to provincial and municipal permitting issues. On February 16, 2018, Burnaby and BC applied to the Federal Court of Appeal for leave to appeal the Burnaby Order. On March 23, 2018, the Federal Court of Appeal denied the application. Burnaby or BC, or both of them, may appeal the decision to the Supreme Court of Canada. A successful appeal at the Supreme Court of Canada could result in the Burnaby Order being quashed.

Other Commercial Matters

Union Pacific Railroad Company Easements Landowner Litigation

A purported class action lawsuit was filed in 2015 in a U.S. District Court in California against Union Pacific Railroad Company (UPRR), SFPP, KMGP and Kinder Morgan Operating L.P. "D" by private landowners who claim to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP for pipeline easements on rights-of-way held by UPRR. Substantially similar follow-on lawsuits were filed in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which are brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, assert claims against UPRR, SFPP, KMGP, and Kinder Morgan Operating L.P. "D" alleging that the defendants' occupation and use of the subsurface real property was improper. Plaintiffs' motions for class certification were denied by the federal courts in Arizona and California. The Ninth Circuit Court of Appeals denied Plaintiffs' request for interlocutory review of the decisions on class certification. The New Mexico and Nevada lawsuits have been stayed. An additional lawsuit was filed in a U.S. District Court in Arizona by private landowners seeking recovery for claims substantially the same as those made in the purported class actions. During first quarter 2018, the parties reached agreements in principle to settle all pending lawsuits on terms that are not material to KMI's results of operations, cash flows or dividends to shareholders.

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that is not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA seeks declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have "frustrated the essential purpose" of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC "in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate" the agreement. As set forth in the terminal use agreement, disputes are meant to be resolved by final and binding arbitration. A three-member arbitration panel conducted an arbitration hearing in January 2017. The arbitration panel informed the parties that it expects to issue its decision on or before May 31, 2018. Eni USA has indicated that it will continue to pay the amounts claimed to be due pending resolution of the dispute. The successful assertion by Eni USA of its claim to terminate or amend its payment obligations under the agreement prior to the expiration of its initial term could have an adverse effect on the business, financial position, results of operations, or cash flows of GLNG and distributions to KMI, a 50% shareholder of GLNG. We view the demand for arbitration to be without merit, and we will continue to contest it vigorously.

Brinckerhoff Merger Litigation

In April 2017, a purported class action suit was filed in the Delaware Court of Chancery by Peter Brinckerhoff, a former EPB unitholder on behalf of a class of former unaffiliated unitholders of EPB, seeking to challenge the $9.2 billion merger of EPB into a subsidiary of KMI as part of a series of transactions in November 2014 whereby KMI acquired all of the outstanding equity interests in KMP, Kinder Morgan Management, LLC and EPB that KMI and its subsidiaries did not already own. The suit alleges that the merger consideration did not sufficiently compensate EPB unitholders for the value of three derivative suits concerning drop down transactions which the derivative plaintiff lost standing to pursue after the merger and which the present suit now alleges were collectively worth as much as $700 million. The suit claims that the alleged failure to obtain sufficient merger consideration for the drop down lawsuits constitutes a breach of the EPB limited partnership agreement and the implied covenant of good faith and fair dealing. The suit also asserts claims against KMI and certain individual defendants for allegedly tortiously interfering with and/or aiding and abetting the alleged breach of the limited partnership agreement. In November 2017, the Court dismissed the suit in its entirety. Brinckerhoff is appealing the dismissal. Also in November 2017, counsel for Brinckerhoff filed a separate lawsuit against KMEP and KMI seeking to recover up to $44 million in attorneys’ fees allegedly incurred in connection with the assertion of derivative claims that Brinckerhoff lost standing to pursue. On April 9, 2018, the Court dismissed the suit in its entirety. We continue to believe that both the merger and the drop down transactions were appropriate and in the best interests of EPB, and we intend to continue to defend these lawsuits vigorously.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which are pending in a U.S. District Court in Nevada, were dismissed, but the dismissal was reversed by the Ninth Circuit Court of Appeals. The U.S. Supreme Court affirmed the Ninth Circuit Court of Appeals in a decision dated April 21, 2015, and the cases were then remanded to the District Court for further consideration and trial, if necessary, of numerous remaining issues. On May 24, 2016, the District Court granted a motion for summary judgment dismissing a lawsuit brought by an industrial consumer in Kansas in which approximately $500 million in damages has been alleged. On March 27, 2018, the Ninth Circuit Court of Appeals reversed the dismissal and remanded the case to the U.S. District Court. Settlements have been reached in class actions originally filed in Kansas and Missouri, which settlements received final court approval and have been paid. In the Wisconsin class action in which approximately $300 million in damages has been alleged against all defendants, the U.S. District Court denied plaintiff’s motion for class certification. The Ninth Circuit Court of Appeals granted plaintiff’s request for an interlocutory appeal of this ruling. There remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, which may be allocated to us in the remaining lawsuits and therefore, our legal exposure, if any, and costs are not currently determinable.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

General

As of March 31, 2018 and December 31, 2017, our total reserve for legal matters was $404 million and $350 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising in our products and natural gas pipeline segments.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a “reasonable basis” for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations, including alleged violations of the Risk Management Program and leak detection and repair requirements of the Clean Air Act. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties, individually or in the aggregate, will be material. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, NGL, natural gas and CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the EPA issued General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member. The LWG agreed to conduct the remedial investigation and feasibility study (RI/FS) leading to the proposed remedy for cleanup of the Portland Harbor site. The EPA issued the FS and the Proposed Plan on June 8, 2016 which included a proposed combination of dredging, capping, and enhanced natural recovery. On January 6, 2017, the EPA issued its Record of Decision (ROD) for the final cleanup plan. The final remedy is more stringent than the remedy proposed in the EPA’s Proposed Plan. The estimated cost increased from approximately $750 million to approximately $1.1 billion, and active cleanup is now expected to take as long as 13 years to complete. KMLT and 90 other parties are involved in a non-judicial allocation process to determine each party’s respective share of the cleanup costs. We are participating in the allocation process on behalf of KMLT and KMBT in connection with their current or former ownership or operation of four facilities located in Portland Harbor. Our share of responsibility for Portland Harbor Superfund Site costs will not be determined until the ongoing non-judicial allocation process is concluded in several years or a lawsuit is filed that results in a judicial decision allocating responsibility. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the site. In addition to CERCLA cleanup costs, we are reviewing and will attempt to settle, if possible, natural resource damage (NRD) claims asserted by state and federal trustees following their natural resource assessment of the site. At this time, we are unable to reasonably estimate the extent of our potential NRD liability.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P., U.S. District Court, Arizona

The Roosevelt Irrigation District filed a lawsuit in 2010 against KMGP, KMEP and others under CERCLA for alleged contamination of the water purveyor’s wells. The First Amended Complaint sought $175 million in damages from approximately 70 defendants. KMGP was dismissed from the suit. On August 6, 2013, plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims against KMEP and SFPP are related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. We filed an answer in response to the Second Amended Complaint and engaged in fact discovery. On March 28, 2018, KMEP and SFPP entered into an agreement to settle all claims made by the Roosevelt Irrigation District on terms that are not material to KMI's results of operations, cash flows or dividends to shareholders.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately twenty uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a potentially responsible party within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting a radiological assessment of the surface of the mines and the immediate vicinity. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given the U.S. is the owner of the Navajo Reservation, the U.S.'s exploration and reclamation activities at the mines, and the pervasive control of such federal agencies over all aspects of the nuclear weapons program. Defendants filed an answer and counterclaims seeking contribution and recovery of response costs allegedly incurred by the federal agencies in investigating uranium impacts on the Navajo Reservation. The counterclaim of defendant EPA has been settled, and no viable claims for reimbursement by the other defendants are known to exist. In August 2017, the District Court found the U.S. liable under CERCLA as owner of the Navajo Reservation. The matter seeking cost recovery and contribution from federal government agencies is set for trial in February 2019. We intend to continue to prosecute and defend this case vigorously.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, Essex, Hudson, Bergen and Passaic Counties, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (PRPs) under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 70 cooperating parties, referred to as the Cooperating Parties Group (CPG), which has entered into AOCs and is directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and comments from the EPA remain pending. Under the second AOC, the CPG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA's preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its Record of Decision (ROD) for the lower eight miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. On October 5, 2016, the EPA entered into an AOC with one member of the PRP group requiring such member to spend $165 million to perform engineering and design work necessary to begin the cleanup of the lower eight miles of the Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete.

In addition, the EPA has notified PRPs, including EPEC Polymers and EPEC Oil Trust that it intends to propose an allocation for the implementation of the remedy for the lower eight miles of the Passaic River Study area. The allocation process has been proposed by the EPA but not yet finalized. There remains significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD. There is also uncertainty as to the impact of the RI/FS that the CPG is currently preparing for portions of the Site. The draft RI/FS was submitted by the CPG in 2015 and proposes a different remedy than the FFS announced by the EPA. Therefore, the scope of potential

EPA claims for the lower eight miles of the Passaic River is not reasonably estimable at this time.

Plaquemines Parish Louisiana Coastal Zone Litigation

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana against TGP and 17 other energy companies, alleging that defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other

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relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP has made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP's oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP's pipeline assets in Bastian Bay in 2013. Anadarko has accepted TGP's tender (limited to oil and gas assets), and Kinetica rejected TGP's tender. The Louisiana Department of Natural Resources (LDNR) and the Louisiana Attorney General (LAG) have intervened in the lawsuit. The Court has separated the defendants into several trial groups with trials set to begin in 2019. The case involving TGP is set for trial in 2020. We will continue to vigorously defend the lawsuit.

Vermilion Parish Louisiana Coastal Zone Litigation

On July 28, 2016, the District Attorney for the Fifteenth Judicial District of Louisiana, purporting to act on behalf of Vermilion Parish and the State of Louisiana, filed a suit in the state district court for Vermilion Parish, Louisiana against TGP and 52 other energy companies, alleging that the defendants' oil and gas and transportation operations associated with the development of several fields in Vermilion Parish (Operational Areas) were conducted in violation of the Coastal Zone Management Act. The suit alleges such operations caused substantial damage to the coastal waters and nearby lands (Coastal Zone) of Vermilion Parish, resulting in the release of pollutants and contaminants into the environment, improper discharge of oil field wastes, the improper use of waste pits and failure to close such pits, and the dredging of canals, which resulted in degradation of the Operational Areas, including erosion of marshes and degradation of terrestrial and aquatic life therein. As a result of such alleged violations of the Coastal Zone Management Act, the suit seeks a judgment against the defendants awarding all appropriate damages, the payment of costs to clear, revegetate, detoxify and otherwise restore the Vermilion Parish Coastal Zone, actual restoration of the affected Coastal Zone to its original condition, and reasonable costs and attorney fees. On September 2, 2016, the case was removed to the U.S. District Court for the Western District of Louisiana. Plaintiffs filed a motion to remand the case to the state district court. On September 26, 2017, the U.S. District Court remanded the case to the State District Court for Vermillion Parish. On March 2, 2018, Plaintiffs dismissed the claims made by Vermilion Parish and the State of Louisiana against TGP. During the pendency of the litigation, the LDNR and the LAG intervened in the lawsuit seeking damages from TGP and the other defendants for alleged violations of the Coastal Zone Management Act. The LDNR and LAG have not yet dismissed their claims against TGP.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. and several individual landowners filed a lawsuit in the State District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG and TGP failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. The SNG assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to SNG's demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial was held during September 2017. We anticipate a ruling in the second quarter 2018. We will continue to vigorously defend the suit, and intend to appeal any adverse ruling that may result from the trial.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. As of March 31, 2018 and December 31, 2017, we have accrued a total reserve for environmental liabilities in the amount of $275 million and $279 million, respectively. In addition, as of both March 31, 2018 and December 31, 2017, we have recorded a receivable of $13 million for expected cost recoveries that have been deemed probable.

10. Recent Accounting Pronouncements

ASU No. 2016-02

On February 25, 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)." This ASU requires that a lessee recognizes assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU No. 2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-04

On January 26, 2017, the FASB issued ASU No. 2017-04, "Simplifying the Test for Goodwill Impairment (Topic 350)" to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. Goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU No. 2017-04 will be effective for us as of January 1, 2020. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-12

On August 28, 2017, the FASB issued ASU No. 2017-12, "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities." This ASU amends and simplifies existing guidance in order to allow companies to more accurately present the economic effects of risk management activities in the financial statements. ASU No. 2017-12 will be effective for us as of January 1, 2019, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2018-01

On January 25, 2018, the FASB issued ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842." This ASU provides an optional transition on practical expedient that, if elected, would not require companies to reconsider its accounting for existing or expired land easements before the adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. ASU No. 2018-01 will be effective for us as of January 1, 2019, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

11. Guarantee of Securities of Subsidiaries

KMI, along with its direct subsidiary KMP, are issuers of certain public debt securities. KMI, KMP and substantially all of KMI's wholly owned domestic subsidiaries are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as Subsidiary Non-Guarantors, the parent issuer, subsidiary issuer and other subsidiaries are all guarantors of each series of public debt. As a result of the cross guarantee agreement, a holder of any of the guaranteed public debt securities issued by KMI or KMP is in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuer and Guarantors. The only amounts that are not available to the holders of each of the guaranteed public debt securities to satisfy the repayment of such securities are the net assets, income and cash flows of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC’s Regulation S-X. We have presented each of the parent and subsidiary issuer in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of March 31, 2018, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $15,828 million, $17,910 million, and $2,535 million, respectively, of Guaranteed Notes outstanding. Included in the Subsidiary Guarantors debt balance as presented in the accompanying March 31, 2018 condensed consolidating balance sheet is approximately $160 million of capital lease obligations that are not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only. These intercompany investments and related activities eliminate in consolidation and are presented separately in the accompanying condensed consolidating balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following 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.

On December 31, 2017, KMP's interests in KMBT were transferred to KMI. The following condensed consolidating financial information reflects this transaction for all periods presented.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended March 31, 2018
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ —	$ —	$ 3,080	$ 386	$ (48)	$ 3,418
Operating Costs, Expenses and Other						
Costs of sales	—	—	979	77	(37)	1,019
Depreciation, depletion and amortization	5	—	484	81	—	570
Other operating (income) expense	(25)	1	743	172	(11)	880
Total Operating Costs, Expenses and Other	(20)	1	2,206	330	(48)	2,469
Operating income (loss)	20	(1)	874	56	—	949
Other Income (Expense)						
Earnings from consolidated subsidiaries	806	745	51	16	(1,618)	—
Earnings from equity investments	—	—	220	—	—	220
Interest, net	(184)	(4)	(273)	(6)	—	(467)
Amortization of excess cost of equity investments and other, net	6	—	(10)	8	—	4
Income Before Income Taxes	648	740	862	74	(1,618)	706
Income Tax Expense	(124)	(2)	(26)	(12)	—	(164)
Net Income	524	738	836	62	(1,618)	542
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(18)	(18)
Net Income Attributable to Controlling Interests	524	738	836	62	(1,636)	524
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net Income Available to Common Stockholders	$ 485	$ 738	$ 836	$ 62	$ (1,636)	$ 485
Net Income	$ 524	$ 738	$ 836	$ 62	$ (1,618)	$ 542
Total other comprehensive loss	(17)	(56)	(57)	(78)	167	(41)
Comprehensive income (loss)	507	682	779	(16)	(1,451)	501
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	6	6
Comprehensive income (loss) attributable to controlling interests	$ 507	$ 682	$ 779	$ (16)	$ (1,445)	$ 507

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Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended March 31, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 9	$ —	$ 3,058	$ 375	$ (18)	$ 3,424
Operating Costs, Expenses and Other						
Costs of sales	—	—	997	71	(7)	1,061
Depreciation, depletion and amortization	4	—	476	78	—	558
Other operating expenses	15	—	691	133	(11)	828
Total Operating Costs, Expenses and Other	19	—	2,164	282	(18)	2,447
Operating (loss) income	(10)	—	894	93	—	977
Other Income (Expense)						
Earnings from consolidated subsidiaries	846	827	102	18	(1,793)	—
Earnings from equity investments	—	—	175	—	—	175
Interest, net	(177)	6	(282)	(12)	—	(465)
Amortization of excess cost of equity investments and other, net	—	—	—	4	—	4
Income Before Income Taxes	659	833	889	103	(1,793)	691
Income Tax Expense	(219)	(2)	(17)	(8)	—	(246)
Net Income	440	831	872	95	(1,793)	445
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(5)	(5)
Net Income Attributable to Controlling Interests	440	831	872	95	(1,798)	440
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net Income Available to Common Stockholders	401	831	872	95	(1,798)	401
Net Income	$ 440	$ 831	$ 872	$ 95	$ (1,793)	$ 445
Total other comprehensive income	68	106	99	21	(226)	68
Comprehensive income	508	937	971	116	(2,019)	513
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(5)	(5)
Comprehensive income attributable to controlling interests	$ 508	$ 937	$ 971	$ 116	$ (2,024)	$ 508

Condensed Consolidating Balance Sheets as of March 31, 2018
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 61	$ —	$ —	$ 237	$ (4)	$ 294
Other current assets - affiliates	7,167	3,972	24,227	918	(36,284)	—
All other current assets	227	41	1,819	260	(13)	2,334
Property, plant and equipment, net	248	—	31,109	8,976	—	40,333
Investments	665	—	6,620	135	—	7,420
Investments in subsidiaries	38,824	37,607	5,433	4,251	(86,115)	—
Goodwill	13,789	22	5,166	3,180	—	22,157
Notes receivable from affiliates	989	20,356	523	839	(22,707)	—
Deferred income taxes	3,494	—	—	—	(1,608)	1,886
Other non-current assets	340	102	4,004	141	—	4,587
Total assets	$ 65,804	$ 62,100	$ 78,901	$ 18,937	$ (146,731)	$ 79,011
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 962	$ 1,300	$ 30	$ 202	$ —	$ 2,494
Other current liabilities - affiliates	13,685	14,216	7,573	810	(36,284)	—
All other current liabilities	362	160	1,889	541	(17)	2,935
Long-term debt	15,068	16,782	3,041	652	—	35,543
Notes payable to affiliates	1,331	448	20,573	355	(22,707)	—
Deferred income taxes	—	—	473	1,135	(1,608)	—
All other long-term liabilities and deferred credits	729	165	969	518	—	2,381
Total liabilities	32,137	33,071	34,548	4,213	(60,616)	43,353
Redeemable noncontrolling interest	—	—	523	—	—	523
Stockholders' equity						
Total KMI equity	33,667	29,029	43,830	14,724	(87,583)	33,667
Noncontrolling interests	—	—	—	—	1,468	1,468
Total stockholders' equity	33,667	29,029	43,830	14,724	(86,115)	35,135
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 65,804	$ 62,100	$ 78,901	$ 18,937	$ (146,731)	$ 79,011

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Condensed Consolidating Balance Sheets as of December 31, 2017
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	$ 3	$ —	$ —	$ 262	$ (1)	$ 264
Other current assets - affiliates	6,214	5,201	22,402	858	(34,675)	—
All other current assets	243	59	1,938	235	(24)	2,451
Property, plant and equipment, net	236	—	31,093	8,826	—	40,155
Investments	665	—	6,498	135	—	7,298
Investments in subsidiaries	37,983	36,728	5,417	4,232	(84,360)	—
Goodwill	13,789	22	5,166	3,185	—	22,162
Notes receivable from affiliates	1,033	20,363	1,233	776	(23,405)	—
Deferred income taxes	3,635	—	—	—	(1,591)	2,044
Other non-current assets	254	164	4,080	183	—	4,681
Total assets	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055
LIABILITIES AND STOCKHOLDERS’ EQUITY						
Liabilities						
Current portion of debt	$ 924	$ 975	$ 805	$ 124	$ —	$ 2,828
Other current liabilities - affiliates	13,225	14,188	6,512	750	(34,675)	—
All other current liabilities	468	347	2,055	508	(25)	3,353
Long-term debt	13,104	18,206	3,052	653	—	35,015
Notes payable to affiliates	2,009	448	20,593	355	(23,405)	—
Deferred income taxes	—	—	449	1,142	(1,591)	—
Other long-term liabilities and deferred credits	689	117	1,462	467	—	2,735
Total liabilities	30,419	34,281	34,928	3,999	(59,696)	43,931
Stockholders’ equity						
Total KMI equity	33,636	28,256	42,899	14,693	(85,848)	33,636
Noncontrolling interests	—	—	—	—	1,488	1,488
Total stockholders’ equity	33,636	28,256	42,899	14,693	(84,360)	35,124
Total Liabilities and Stockholders’ Equity	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055

Condensed Consolidating Statements of Cash Flows for the Three Months Ended March 31, 2018
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (302)	$ 838	$ 2,356	$ 263	$ (2,181)	$ 974
Cash flows from investing activities						
Acquisitions of assets and investments	—	—	(20)	—	—	(20)
Capital expenditures	(19)	—	(451)	(237)	—	(707)
Proceeds from sales of equity investments	—	—	33	—	—	33
Sales of property, plant and equipment, and other net assets, net of removal costs	2	—	—	(1)	—	1
Contributions to investments	—	—	(64)	(2)	—	(66)
Distributions from equity investments in excess of cumulative earnings	559	—	42	—	(559)	42
Funding (to) from affiliates	(3,074)	34	(1,388)	(248)	4,676	—
Loans to related party	—	—	(8)	—	—	(8)
Net cash (used in) provided by investing activities	(2,532)	34	(1,856)	(488)	4,117	(725)
Cash flows from financing activities						
Issuances of debt	5,961	—	—	78	—	6,039
Payments of debt	(3,929)	(975)	(777)	(3)	—	(5,684)
Debt issue costs	(17)	—	—	(4)	—	(21)
Cash dividends - common shares	(277)	—	—	—	—	(277)
Cash dividends - preferred shares	(39)	—	—	—	—	(39)
Repurchases of shares	(250)	—	—	—	—	(250)
Funding from affiliates	1,444	1,402	1,639	191	(4,676)	—
Contributions from investment partner	—	—	38	—	—	38
Contributions from parents	—	—	3	—	(3)	—
Contributions from noncontrolling interests	—	—	—	—	3	3
Distributions to parents	—	(1,289)	(1,403)	(62)	2,754	—
Distributions to noncontrolling interests	—	—	—	—	(17)	(17)
Other, net	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	2,892	(862)	(500)	200	(1,939)	(209)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	(3)	—	(3)
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	58	10	—	(28)	(3)	37
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3	1	—	323	(1)	326
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 61	$ 11	$ —	$ 295	$ (4)	$ 363

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Condensed Consolidating Statements of Cash Flows for the Three Months Ended March 31, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (862)	$ 820	$ 2,983	$ 231	$ (2,286)	$ 886
Cash flows from investing activities						
Acquisitions of assets and investments	—	—	(4)	—	—	(4)
Capital expenditures	(19)	—	(582)	(63)	—	(664)
Sales of property, plant and equipment, and other net assets, net of removal costs	5	—	45	21	—	71
Contributions to investments	(15)	—	(173)	(3)	—	(191)
Distributions from equity investments in excess of cumulative earnings	463	—	119	—	(444)	138
Funding (to) from affiliates	(1,678)	406	(1,823)	(213)	3,308	—
Net cash (used in) provided by investing activities	(1,244)	406	(2,418)	(258)	2,864	(650)
Cash flows from financing activities						
Issuances of debt	1,517	—	—	—	—	1,517
Payments of debt	(1,517)	(600)	(2)	(3)	—	(2,122)
Debt issue costs	(1)	—	—	—	—	(1)
Cash dividends - common shares	(280)	—	—	—	—	(280)
Cash dividends - preferred shares	(39)	—	—	—	—	(39)
Funding from affiliates	2,129	636	463	80	(3,308)	—
Contribution from investment partner	—	—	391	—	—	391
Contributions from parents	—	—	6	—	(6)	—
Contributions from noncontrolling interests	—	—	—	—	6	6
Distributions to parents	—	(1,272)	(1,421)	(47)	2,740	—
Distributions to noncontrolling interests	—	—	—	—	(9)	(9)
Other, net	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	1,808	(1,236)	(563)	30	(577)	(538)
Effect of exchange rate changes on cash, cash equivalents and restricted deposits	—	—	—	1	—	1
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	(298)	(10)	2	4	1	(301)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	471	36	9	272	(1)	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 173	$ 26	$ 11	$ 276	$ —	$ 486

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.
General and Basis of Presentation
The following discussion and analysis should be read in conjunction with our accompanying interim consolidated financial statements and related notes included elsewhere in this report, and in conjunction with (i) our consolidated financial statements and related notes and (ii) our management's discussion and analysis of financial condition and results of operations included in our 2017 Form 10-K.

On January 1, 2018, we adopted ASU No. 2014-09, "Revenue from Contracts with Customers" and a series of related accounting standard updates (collectively referred to as "Topic 606") designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see Note 6 "Revenue Recognition" to our consolidated financial statements.

Suspension of Non-Essential Spending on Trans Mountain Expansion Project

On April 8, 2018, KML announced that it was suspending all non-essential activities and related spending on the TMEP. KML also announced that under current circumstances, specifically including the continued actions in opposition to the TMEP by the Province of British Columbia (BC), it will not commit additional shareholder resources to the TMEP. However, KML further announced that it will consult with various stakeholders in an effort to reach agreements by May 31, 2018 that may allow the TMEP to proceed. KML stated it is difficult to conceive of any scenario in which it would proceed with the TMEP if an agreement is not reached by May 31, 2018. The focus in those consultations will be on two principles: clarity on the path forward, particularly with respect to the ability to construct through BC, and adequate protection of KML shareholders.

KML had previously announced a "primarily permitting" strategy for the first half of 2018, focused on advancing the permitting process, rather than spending at full construction levels, until it obtained greater clarity on outstanding permits, approvals and judicial reviews. Rather than achieving greater clarity, the TMEP is now facing unquantifiable risk. Previously, opposition by BC was manifesting itself largely through BC's participation in an ongoing judicial review. Unfortunately, BC has now been asserting broad jurisdiction and reiterating its intention to use that jurisdiction to stop the TMEP. On April 18, 2018, the Attorney General for BC announced that the Province will file a reference case by April 30, 2018, presenting a constitutional question to the BC Court of Appeal. The reference question has yet to be publicly disclosed; it is anticipated the question will seek to define the extent of BC's constitutional jurisdiction, if any, to regulate marine or environmental risks, or the transport of certain petroleum products into BC. BC's intention in that regard has been neither validated nor quashed, and BC has continued to threaten unspecified additional actions to prevent the TMEP success. Those actions have created even greater, and growing, uncertainty with respect to the regulatory landscape facing the TMEP. In addition, the parties still await judicial decisions on challenges to the original Order in Council and the BC Environmental Assessment Certificate approving the TMEP. These items, combined with the impending approach of critical construction windows, the lead-time required to ramp up spending, and the imperative that KML avoid incurring significant debt while lacking the necessary clarity, brought KML to the decision it announced on April 8, 2018. Given the current uncertain conditions, KML is not updating its cost and schedule estimate at this time. However, construction delays are likely to entail increased costs due to a variety of factors including extended personnel, equipment and facilities charges, storage charges for unused material and equipment, extended debt service, and inflation, among others.

In the event the TMEP is terminated, resulting impairments, foregone capitalized equity costs and potential wind down costs would have a significant effect on our results of operations. Potential impairments would be recognized primarily in the period in which the decision to terminate is made. As of March 31, 2018, C$1,135 million has been spent on development of the TMEP.

Also, see "Information Regarding Forward Looking Statements" and Part I, Item 1A. "Risk Factors—Expanding our existing assets and constructing new assets is part of our growth strategy. Our ability to begin and complete construction on expansion and new-build projects may be inhibited by difficulties in obtaining, or our inability to obtain, permits and rights-of-way, as well as public opposition, cost overruns, inclement weather and other delays" in our 2017 Form 10-K for a more detailed description of risks related to operating our business.

Results of Operations
Overview

Our management evaluates our performance primarily using the measures of Segment EBDA and, as discussed below under "—Non-GAAP Financial Measures," DCF, and Segment EBDA before certain items. Segment EBDA is a useful measure of our operating performance because it measures the operating results of our segments before DD&A and certain expenses that are generally not controllable by our business segment operating managers, such as general and administrative expenses, interest expense, net, and income taxes. Our general and administrative expenses include such items as employee benefits, insurance, rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services.

In our discussions of the operating results of individual businesses that follow, we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods.

Consolidated Earnings Results

	Three Months Ended March 31,			
	2018	2017	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$1,136	$1,055	$ 81	8 %
CO_2	199	218	(19)	(9)%
Terminals	295	307	(12)	(4)%
Products Pipelines	259	287	(28)	(10)%
Kinder Morgan Canada	46	43	3	7 %
Total Segment EBDA(b)	1,935	1,910	25	1 %
DD&A	(570)	(558)	(12)	(2)%
Amortization of excess cost of equity investments	(32)	(15)	(17)	(113)%
General and administrative and corporate charges(c)	(160)	(181)	21	12 %
Interest, net(d)	(467)	(465)	(2)	— %
Income before income taxes	706	691	15	2 %
Income tax expense	(164)	(246)	82	33 %
Net income	542	445	97	22 %
Net income attributable to noncontrolling interests	(18)	(5)	(13)	(260)%
Net income attributable to Kinder Morgan, Inc.	524	440	84	19 %
Preferred Stock Dividends	(39)	(39)	—	— %
Net income Available to Common Stockholders	$485	$401	$ 84	21 %

(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, other expense (income), net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

Certain items affecting Total Segment EBDA (see "—Non-GAAP Measures" below)

(b) 2018 and 2017 amounts include a net decrease in earnings of $16 million and a net increase in earnings of $37 million, respectively, related to the combined effect of the certain items impacting Total Segment EBDA. The extent to which these items affect each of our business segments is discussed below in the footnotes to the tables within "—Segment Earnings Results."

(c) 2018 and 2017 amounts include a net decrease in expense of $4 million and a net increase in expense of $7 million, respectively, related to the combined effect of the certain items related to general and administrative expense and corporate charges disclosed below in "—General and Administrative and Corporate Charges, Interest, net and

Noncontrolling Interests."

(d) 2018 and 2017 amounts include net decreases in expense of $5 million and $12 million, respectively related to the combined effect of the certain items related to interest expense, net disclosed below in "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

The certain item totals reflected in footnotes (b), (c), and (d) to the table above accounted for a $49 million decrease in income before income taxes for the first quarter of 2018, as compared to the same prior year period (representing the difference between a decrease of $7 million and an increase of $42 million in income before income taxes for the first quarter of 2018 and 2017, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining increase of $64 million (10%) from the prior year quarter in income before income taxes is primarily attributable to increased performance from our Natural Gas Pipelines and CO_2 business segments and decreased general and administrative expense, partially offset by increased DD&A expense.

Non-GAAP Financial Measures

Our non-GAAP performance measures are DCF, both in the aggregate and per share, and Segment EBDA before certain items. Certain items, as used to calculate our non-GAAP measures, are items that are required by GAAP to be reflected in net income, but typically either (i) do not have a cash impact (for example, asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example certain legal settlements, enactment of new tax legislation and casualty losses).

Our non-GAAP performance measures described below should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of DCF and Segment EBDA before certain items may differ from similarly titled measures used by others. You should not consider these non-GAAP performance measures in isolation or as substitutes for an analysis of our results as reported under GAAP. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. Management compensates for the limitations of these non-GAAP performance measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes.

DCF

DCF is calculated by adjusting net income available to common stockholders before certain items for DD&A, total book and cash taxes, sustaining capital expenditures and other items. DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt and preferred stock dividends, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. A reconciliation of DCF to net income available to common stockholders is provided in the table below. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Reconciliation of Net Income Available to Common Stockholders to DCF

	Three Months Ended March 31,	
	2018	2017
	(In millions, except per share amounts)	
Net Income Available to Common Stockholders	$485	$401
Add/(Subtract):		
Certain items before book tax(a)	51	(42)
Book tax certain items(b)	(3)	12
Impact of 2017 Tax Reform(c)	(44)	—
Total certain items	4	(30)
Net income available to common stockholders before certain items	489	371
Add/(Subtract):		
DD&A expense(d)	690	671
Total book taxes(e)	184	261
Cash taxes(f)	(13)	3
Other items(g)	11	13
Sustaining capital expenditures(h)	(114)	(104)
DCF	$1,247	$1,215
Weighted average common shares outstanding for dividends(i)	2,218	2,239
DCF per common share	$0.56	$0.54
Declared dividend per common share	$0.20	$0.125

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(a) Consists of certain items summarized in footnotes (b) through (d) to the "—Results of Operations—Consolidated Earnings Results" table included above, and described in more detail below in the footnotes to tables included in both our management's discussion and analysis of segment results and "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

(b) Represents income tax provision on certain items, plus discrete income tax certain items.

(c) Represents our share of certain equity investees' 2017 Tax Reform provisional adjustments.

(d) Includes DD&A and amortization of excess cost of equity investments. 2018 and 2017 amounts also include $88 million and $98 million, respectively, of our share of certain equity investees' DD&A, net of the noncontrolling interests' portion of KML DD&A and consolidating joint venture partners' share of DD&A.

(e) Excludes book tax certain items. 2018 and 2017 amounts also include $17 million and $27 million, respectively, of our share of taxable equity investees' book taxes, net of the noncontrolling interests' portion of KML book taxes.

(f) 2018 amount includes $(10) million of our share of taxable equity investees' cash taxes.

(g) Consists primarily of non-cash compensation associated with our restricted stock program.

(h) 2018 and 2017 amounts include $(16) million and $(18) million, respectively, of our share of (i) certain equity investees', (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures.

(i) Includes restricted stock awards that participate in common share dividends.

Segment EBDA Before Certain Items

Segment EBDA before certain items is used by management in its analysis of segment performance and management of our business. General and administrative expenses are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe

Segment EBDA before certain items is a significant performance metric because it provides us and external users of our financial statements additional insight into the ability of our segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a performance measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Segment EBDA before certain items is Segment EBDA.

In the tables for each of our business segments under "— Segment Earnings Results" below, Segment EBDA before certain items is calculated by adjusting the Segment EBDA for the applicable certain item amounts, which are totaled in the tables and described in the footnotes to those tables.

Segment Earnings Results

Natural Gas Pipelines

	Three Months Ended March 31,		
	2018	2017	
	(In millions, except operating statistics)		
Revenues(a)	$2,166	$2,171	
Operating expenses(b)	(1,232)	(1,272)	
Earnings from equity investments(b)	185	146	
Other, net	17	10	
Segment EBDA(b)	1,136	1,055	
Certain items(b)	(54)	(36)	
Segment EBDA before certain items	$1,082	$1,019	
Change from prior period			
Revenues before certain items	$4	—	%
Segment EBDA before certain items	$63	6	%
Natural gas transport volumes (BBtu/d)(c)	32,124	29,326	
Natural gas sales volumes (BBtu/d)(c)	2,491	2,563	
Natural gas gathering volumes (BBtu/d)(c)	2,731	2,712	
Crude/condensate gathering volumes (MBbl/d)(c)	281	272	

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Certain items affecting Segment EBDA

(a) 2018 and 2017 amounts include increases in revenue of $6 million and $15 million, respectively, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales.

(b) In addition to the revenue certain items described in footnote (a) above: 2018 amount also includes (i) an increase in earnings of $44 million for our share of certain equity investees' 2017 Tax Reform provisional adjustments; (ii) an increase in earnings of $6 million related to the release of certain sales and use tax reserves; and (iii) a $2 million decrease in earnings from other certain items. 2017 amount also includes (i) an increase in earnings from an equity investment of $22 million on the sale of a claim related to the early termination of a long-term natural gas transportation contract and (ii) a $1 million decrease in earnings from other certain items.

Other

(c) Joint venture throughput is reported at our ownership share.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three month periods ended March 31, 2018 and 2017:

Three Months Ended March 31, 2018 versus Three Months Ended March 31, 2017

	Segment EBDA before certain items increase/(decrease)	Revenues before certain items increase/(decrease)
	(In millions, except percentages)	

Texas Intrastate Natural Gas Pipeline Operations	$34	31 %	$ 11	1 %
Hiland Midstream	10	22 %	(15)	(9)%
NGPL	7	58 %	9	n/a
EPNG	6	5 %	9	5 %
SNG(a)	6	18 %	—	— %
Citrus(a)	6	29 %	—	— %
TGP	(15)	(5)%	10	3 %
All others (including eliminations)	9	4 %	(20)	(4)%
Total Natural Gas Pipelines	$63	6 %	$ 4	— %

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n/a - not applicable
(a) Equity investment.

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The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three month periods ended March 31, 2018 and 2017:

- increase of $34 million (31%) from our Texas intrastate natural gas pipeline operations (including the operations of its Kinder Morgan Tejas, Border, Kinder Morgan Texas, North Texas and Mier-Monterrey Mexico pipeline systems) was primarily due to higher sales margin as a result of higher average sales rate and higher transportation revenues primarily due to higher volumes, both driven by greater weather-related demand;
- increase of $10 million (22%) from Hiland Midstream primarily due to higher natural gas margins resulting from increased inlet volumes and renegotiated contracts, and higher crude oil margins driven by higher crude oil sales volumes and crude oil sales prices. The $15 million decrease in revenues is primarily due to the $89 million effect of the January 1, 2018 adoption of Topic 606 as discussed in Note 6 “Revenue Recognition” to our consolidated financial statements, partially offset by an increase of $74 million in sales revenues, primarily natural gas liquids and crude oil;
- increase of $7 million (58%) from NGPL due to lower interest expense and greater transport revenue resulting from increased weather-related demand, power demand and deliveries to Mexico:
- increase of $6 million (5%) from EPNG primarily due to higher transportation revenues driven by incremental Permian capacity sales;
- increase of $6 million (18%) from SNG primarily due to higher usage revenues from higher throughput and higher park and loan revenues both resulting from increased weather-related demand and lower interest expense resulting from lower debt balances and interest rates and lower operations and maintenance expense;
- increase of $6 million (29%) from Citrus primarily due to lower income tax expense due to the lower U.S. federal corporate income tax rate in first quarter 2018 and higher transportation revenues; and
- decrease of $15 million (5%) from TGP primarily due to lower firm transportation revenues driven by lower capacity sales partially offset by increased revenues from expansion projects placed in service in latter part of 2017. Revenues were also impacted by an increase in operational gas sales which was offset by an increase in associated gas cost.

CO2

	Three Months Ended March 31,	
	2018	2017
	(In millions, except operating statistics)	
Revenues(a)	$304	$303
Operating expenses	(115)	(97)
Other income(b)	—	1
Earnings from equity investments	10	11
Segment EBDA(b)	199	218
Certain items(b)	38	4
Segment EBDA before certain items	$237	$222
Change from prior period	Increase/(Decrease)	
Revenues before certain items	$34	11 %
Segment EBDA before certain items	$15	7 %
Southwest Colorado CO_2 production (gross)(Bcf/d)(c)	1.3	1.3
Southwest Colorado CO_2 production (net)(Bcf/d)(c)	0.6	0.7
SACROC oil production (gross)(MBbl/d)(d)	29.5	28.3
SACROC oil production (net)(MBbl/d)(e)	24.6	23.6
Yates oil production (gross)(MBbl/d)(d)	17.0	17.9
Yates oil production (net)(MBbl/d)(e)	7.7	8.0
Katz, Goldsmith and Tall Cotton oil production (gross)(MBbl/d)(d)	8.6	7.3

Katz, Goldsmith and Tall Cotton oil production (net)(MBbl/d)(e)	7.3	6.2
NGL sales volumes (net)(MBbl/d)(e)	10.2	10.2
Realized weighted-average oil price per Bbl(f)	$59.72	$58.14
Realized weighted-average NGL price per Bbl(g)	$30.39	$24.50

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Certain items affecting Segment EBDA

(a) 2018 and 2017 amounts include unrealized losses of $38 million and $5 million, respectively, related to derivative contracts used to hedge forecasted commodity sales.

(b) In addition to the revenue certain items described in footnote (a) above: 2017 amount also includes a $1 million decrease in expense related to source and transportation project write-offs.

Other

(c) Includes McElmo Dome and Doe Canyon sales volumes.

(d) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, an approximately 99% working interest in the Katz unit and a 99% working interest in the Goldsmith Landreth unit and a 100% working interest in the Tall Cotton field.

(e) Net after royalties and outside working interests.

(f) Includes all crude oil production properties.

(g) Includes all NGL sales.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three month periods ended March 31, 2018 and 2017.

Three Months Ended March 31, 2018 versus Three Months Ended March 31, 2018 versus Three Months Ended March 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(5)	(6)%	$ 9	10 %
Oil and Gas Producing Activities	20	14 %	23	10 %
Intrasegment eliminations	—	— %	2	18 %
Total CO2	$15	7 %	$ 34	11 %

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three month periods ended March 31, 2018 and 2017:

- decrease of $5 million (6%) from our Source and Transportation activities primarily due to lower sales margin of $4 million driven by lower volumes of $8 million partially offset by higher contract sales prices of $4 million, and lower other revenues of $1 million. The $9 million increase in revenues is primarily due to the effect of the January 1, 2018 adoption of Topic 606, which increased both revenues and operating expenses (costs of sales) by $14 million, as discussed in Note 6 “Revenue Recognition” to our consolidated financial statements; and
- increase of $20 million (14%) from our Oil and Gas Producing activities primarily due to increased revenues of $23 million driven by higher commodity prices of $12 million and higher volumes of $11 million partially offset by an increase of $3 million in operating expenses.

Terminals

	Three Months Ended March 31,	
	2018	2017
	(In millions, except operating statistics)	
Revenues(a)	$ 493	$ 487
Operating expenses(b)	(206)	(179)
Other expense(b)	—	(7)
Earnings from equity investments	7	5
Other, net	1	1
Segment EBDA(b)	295	307
Certain items(b)	1	(5)
Segment EBDA before certain items	$ 296	$ 302
Change from prior period	Increase/(Decrease)	
Revenues before certain items	$ 7	1 %
Segment EBDA before certain items	$ (6)	(2)%
Bulk transload tonnage (MMtons)	14.4	14.4
Ethanol (MMBbl)	14.8	17.7
Liquids leasable capacity (MMBbl)	88.8	85.8
Liquids utilization %(c)	91.0 %	95.2 %

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Certain items affecting Segment EBDA

(a) 2018 and 2017 amounts include increases in revenue of $1 million and $2 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers.

(b) In addition to the revenue certain items described in footnote (a) above: 2018 amount also includes an increase in expense of $2 million related to hurricane repairs. 2017 amount also includes (i) a decrease in expense of $10 million related to accrued dredging costs; and (ii) $7 million related to losses on impairments and divestitures.

Other

(c) The ratio of our actual leased capacity to our estimated capacity.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three month periods ended March 31, 2018 and 2017.

Three Months Ended March 31, 2018 versus Three Months Ended March 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Gulf Central	$(6)	(23)%	$ (6)	(18)%
Northeast	(3)	(10)%	(2)	(4)%
Alberta Canada	4	12 %	5	13 %

Marine Operations	3	7 %	17	26 %
Gulf Liquids	2	3 %	6	6 %
All others (including intrasegment eliminations)	(6)	(6)%	(13)	(7)%
Total Terminals	$(6)	(2)%	$ 7	1 %

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three month periods ended March 31, 2018 and 2017:

- decrease of $6 million (23%) from our Gulf Central terminals primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017;
- decrease of $3 million (10%) from our Northeast terminals primarily due to non-renewal of certain customer contracts at our Staten Island terminal and lower contract rates;

- increase of $4 million (12%) from our Alberta Canada terminals primarily due to placing our Base Line Terminal joint venture into service in January 2018 and higher revenues at our Edmonton Rail Terminal joint venture primarily due to an adjustment in terminal fees in connection with a favorable arbitration ruling and favorable foreign exchange rates;
- increase of $3 million (7%) from our Marine Operations related to the incremental earnings from the March 2017, June 2017, July 2017 and December 2017 deliveries of the Jones Act tankers, the American Freedom, Palmetto State, American Liberty and American Pride, respectively, partially offset by decreased contributions from existing Jones Act tankers driven by lower charter rates; and
- increase of $2 million (3%) from our Gulf Liquids terminals primarily driven by strong organic volume growth across our Houston Ship Chanel facilities as well as contributions from expansion projects at our Pasadena Terminal and the Kinder Morgan Export Terminal.

Products Pipelines

	Three Months Ended March 31,	
	2018	2017
	(In millions, except operating statistics)	
Revenues	$ 399	$ 402
Operating expenses(a)	(158)	(129)
Earnings from equity investments	18	13
Other, net	—	1
Segment EBDA(a)	259	287
Certain items(a)	31	—
Segment EBDA before certain items	$ 290	$ 287
Change from prior period	Increase/(Decrease)	
Revenues	$ (3)	(1)%
Segment EBDA before certain items	$ 3	1 %
Gasoline (MBbl/d)(b)	979	992
Diesel fuel (MBbl/d)	341	323
Jet fuel (MBbl/d)	289	285
Total refined product volumes (MBbl/d)(c)	1,609	1,600
NGL (MBbl/d)(c)	116	106
Crude and condensate (MBbl/d)(c)	329	348
Total delivery volumes (MBbl/d)	2,054	2,054
Ethanol (MBbl/d)(d)	120	110

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Certain items affecting Segment EBDA

(a) 2018 amount includes an increase in expense of $31 million associated with a certain Pacific operations litigation matter.

Other

(b) Volumes include ethanol pipeline volumes.

(c) Joint venture throughput is reported at our ownership share.

(d) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three month periods ended March 31, 2018 and 2017.

Three Months Ended March 31, 2018 versus Three Months Ended March 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Double H pipeline	$5	33 %	$ 4	20 %
Cochin pipeline	5	22 %	3	8 %
Crude & Condensate Pipeline	(10)	(18)%	(7)	(12)%
All others (including eliminations)	3	2 %	(3)	(1)%
Total Products Pipelines	$3	1 %	$ (3)	(1)%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three month periods ended March 31, 2018 and 2017:

- increase of $5 million (33%) from Double H pipeline was primarily due to increased recognition of deficiency revenue;
- increase of $5 million (22%) from Cochin pipeline primarily due to higher services revenues driven by higher volumes and partially driven by integrity work during the first quarter of 2017; and
- decrease of $10 million (18%) from our Kinder Morgan Crude & Condensate Pipeline was primarily due to lower services revenues driven by a decrease in pipeline throughput volumes.

Kinder Morgan Canada

	Three Months Ended March 31,	
	2018	2017
	(In millions, except operating statistics)	
Revenues	$ 61	$ 59
Operating expenses	(24)	(20)
Other, net	9	4
Segment EBDA	$ 46	$ 43
Change from prior period	Increase/(Decrease)	
Revenues	$ 2	3 %
Segment EBDA	$ 3	7 %
Transport volumes (MBbl/d)(a)	288	307

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(a) Represents Trans Mountain pipeline system volumes.

For the comparable three month periods of 2018 and 2017, the Kinder Morgan Canada business segment had an increase in Segment EBDA of $3 million (7%) primarily due to higher capitalized equity financing costs due to spending on TMEP.

General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Three Months Ended March 31,			
	2018	2017	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative and corporate charges(a)	$160	$181	$ (21)	(12)%
Certain items(a)	4	(7)	11	157 %
General and administrative and corporate charges before certain items(a)	$164	$174	$ (10)	(6)%
Interest, net(b)	$467	$465	$ 2	— %
Certain items(b)	5	12	(7)	(58)%
Interest, net, before certain items(b)	$472	$477	$ (5)	(1)%
Net income attributable to noncontrolling interests	$18	$5	$ 13	260 %
Net income attributable to noncontrolling interests before certain items	$18	$5	$ 13	260 %

Certain items

(a) 2018 and 2017 amounts include increases in expense of $6 million and $2 million, respectively, related to certain corporate litigation matters. 2018 amount also includes (i) a decease in expense of $12 million related to the release of certain sales and use tax reserves and (ii) an increase in expense of $2 million related to other certain items. 2017 amount also includes (i) an increase in expense of $4 million related to acquisition costs and (ii) an increase in expense of $1 million related to other certain items.

(b) 2018 and 2017 amounts include (i) decreases in interest expense of $10 million and $15 million, respectively, related to non-cash debt fair value adjustments associated with acquisitions and (ii) increases in interest expense of $5 million and $3 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness.

The decrease in general and administrative expenses and corporate charges before certain items of $10 million in the first quarter of 2018 when compared with the same quarter in the prior year was primarily driven by higher capitalized costs and lower legal costs.

In the table above, we report our interest expense as “net,” meaning that we have subtracted interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense net of interest income before certain items for the first quarter of 2018 when compared with the same quarter in the prior year decreased $5 million. The decrease in interest expense was due to lower weighted average debt balances partially offset by higher short-term interest rates.

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of March 31, 2018 and December 31, 2017, approximately 31% and 28%, respectively, of our debt balances (excluding debt fair value adjustments) were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 4 “Risk Management—Interest Rate Risk Management” to our consolidated financial statements.

Net income attributable to noncontrolling interests represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not owned by us. Net income attributable to noncontrolling interests before certain items for the first quarter of 2018 when compared with the same quarter in the prior year increased $13 million primarily due to the May 30, 2017 sale of approximately 30% of our Canadian business operations to the public in the KML IPO.

Income Taxes

Our tax expense for the three months ended March 31, 2018 was approximately $164 million as compared with $246 million for the same period of 2017. The $82 million decrease in tax expense was primarily due to the reduction in the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

Liquidity and Capital Resources

General

As of March 31, 2018, we had $294 million of “Cash and cash equivalents,” an increase of $30 million (11%) from December 31, 2017. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in “—Short-term Liquidity”), and cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

We have consistently generated substantial cash flow from operations, providing a source of funds of $974 million and $886 million in the first three months of 2018 and 2017, respectively. The period-to-period increase is discussed below in “Cash Flows—Operating Activities.” Generally, we rely on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, dividend payments and our growth capital expenditures.

Since its May 2017 IPO, KML has utilized its own funding sources for the TMEP’s capital expenditures. However, on April 8, 2018, KML announced that it had suspended non-essential spending on the TMEP (see “—General and Basis of Presentation—Suspension of Non-Essential Spending on Trans Mountain Expansion Project”). If TMEP construction continues past May 31, 2018, we expect KML to fund its TMEP capital expenditures, and other project capital expenditures, through (i) additional borrowings on KML’s Credit Facility; (ii) the additional issuance of KML preferred shares; (iii) the issuance of additional KML restricted voting stock; (iv) the issuance of KML long-term notes payable; and (v) KML’s retained cash flow from operations or a combination of the above.

Generally, we expect that our short-term liquidity needs will be met primarily through retained cash from operations, short-term borrowings or by issuing new long-term debt to refinance certain of our maturing long-term debt obligations. We also expect that KMI’s current common stock dividend level will allow us to use retained cash to fund our other growth projects and the share repurchase program in 2018. Moreover, as a result of our current common stock dividend policy and our continued focus on allocating capital to high return opportunities, we do not expect the need to access the equity capital markets to fund our other growth projects for the foreseeable future.

Short-term Liquidity

As of March 31, 2018, our principal sources of short-term liquidity are (i) our $5.0 billion revolving credit facility and associated $4.0 billion commercial paper program; (ii) the KML Credit Facility (for the purpose of funding KML’s expenditures as established by the KML Credit Facility agreements) and (iii) cash from operations. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under ours and KML’s respective credit facilities. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations.

As of March 31, 2018, our $2,494 million of short-term debt consisted primarily of (i) $275 million outstanding borrowings under the KMI $5.0 billion revolving credit facility; (ii) $210 million outstanding under our $4.0 billion commercial paper program; (iii) $78 million outstanding borrowings under the KML C$4.0 billion revolving construction facility; and (iv) $1,777 million of senior notes that mature in the next year. We intend to refinance our short-term debt through credit facility borrowings, commercial paper borrowings, or by issuing new long-term debt or paying down short-term debt using cash retained from operations. Our short-term debt balance as of December 31, 2017 was $2,828 million.

We had working capital (defined as current assets less current liabilities) deficits of $2,801 million and $3,466 million as of March 31, 2018 and December 31, 2017, respectively. Our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we generally expect to pay down using retained cash from operations. The overall $665 million (19%) favorable change from year-end 2017 was primarily due to a larger amount of maturing debt that was refinanced with long-term debt in the first quarter of 2018 and a net decrease in accrued interest. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities.

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures (which we also refer to as discretionary capital expenditures). Expansion capital expenditures are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF (see "Results of Operations—Distributable Cash Flow"). With respect to our oil and gas producing activities, we classify a capital expenditure as an expansion capital expenditure if it is expected to increase capacity or throughput (i.e., production capacity) from the capacity or throughput immediately prior to the making or acquisition of such additions or improvements. Maintenance capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of maintenance capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those maintenance capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional maintenance capital expenditures that we expect to produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as maintenance/sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as maintenance capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion. The classification has an impact on DCF because capital expenditures that are classified as expansion capital expenditures are not deducted from DCF, while those classified as maintenance capital expenditures are.

Our capital expenditures for the three months ended March 31, 2018, and the amount we expect to spend for the remainder of 2018 to sustain and grow our businesses are as follows (see "—General and Basis of Presentation—Suspension of Non-Essential Spending on Trans Mountain Expansion Project" for more information related to the TMEP:

	Three Months Ended March 31, 2018	2018 Remaining	Total 2018
	(In millions)		
Sustaining capital expenditures(a)(c)	$114	$ 558	$672
KMI Discretionary capital investments(b)(c)(d)(e)	$490	$ 1,856	$2,346
KML Discretionary capital investments(c)(f)	$190	$ 1,135	$1,325

(a) Three months ended March 31, 2018, 2018 Remaining, and Total 2018 amounts include $16 million, $96 million, and $112 million, respectively, for our proportionate share of (i) certain equity investee's, (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures.

(b) Three months ended March 31, 2018 amount includes $30 million of our contributions to certain unconsolidated joint ventures for capital investments.

(c) Three months ended March 31, 2018 amount includes $41 million of net changes from accrued capital expenditures, contractor retainage, and other.

(d) Three months ended March 31, 2018 amount excludes KML capital expenditures as it has the capacity to draw on its construction credit facility to fund its capital expenditures.

(e) 2018 Remaining amount includes our estimated contributions to certain unconsolidated joint ventures, net of contributions estimated from certain partners in non-wholly owned consolidated subsidiaries for capital investments.

(f) Three months ended March 31, 2018, 2018 Remaining and Total 2018 amounts include approximately $166 million, $1,049 million and $1,215 million, respectively, on the TMEP.

Off Balance Sheet Arrangements

Other than commitments for the purchase of property, plant and equipment discussed below, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2017 in our 2017 Form 10-K.

Commitments for the purchase of property, plant and equipment as of March 31, 2018 and December 31, 2017 were $760 million and $845 million, respectively.

Cash Flows

Operating Activities

The net increase of $88 million in cash provided by operating activities for the three months ended March 31, 2018 compared to the respective 2017 period was primarily attributable to:

- a $56 million increase associated with net changes in working capital items and non-current assets and liabilities; and
- a $32 million increase in operating cash flow resulting from the combined effects of adjusting the $97 million increase in net income for the period-to-period net decrease in non-cash items including the following: (i) change in fair market value of derivative contracts; (ii) DD&A expenses (including amortization of excess cost of equity investments); (iii) deferred income taxes; and (iv) earnings from equity investments.

Investing Activities

The $75 million net increase in cash used in investing activities for the three months ended March 31, 2018 compared to the respective 2017 period was primarily attributable to:

- a $96 million decrease in cash related to distributions received from equity investments in excess of cumulative earnings, primarily driven by the lower distributions from Midcontinent Express Pipeline LLC and Ruby Pipeline Holding Company, L.L.C. in the 2018 period compared to the 2017 period;
- $70 million lower cash proceeds from sale of property, plant and equipment and other net assets in the 2018 period compared to the 2017 period; and
- a $43 million increase in capital expenditures in the 2018 period over the comparative 2017 period primarily due to higher expenditures related to natural gas and TMEP, partially reduced by lower expenditures in our Terminals segment; partially offset by,
- a $125 million decrease in cash used for contributions to equity investments primarily due to lower contributions we made to NGPL Holdings LLC, SNG and Utopia Holding LLC in the 2018 period compared to the 2017 period;

Financing Activities

The net decrease of $329 million in cash used in financing activities for the three months ended March 31, 2018 compared to the respective 2017 period was primarily attributable to:

- a $940 million net increase in cash related to debt activity as a result of net debt issuances in the 2018 period compared to net debt payments in the 2017 period. See Note 2 “Debt” for further information regarding our debt activity; partially offset by
- a $353 million decrease in cash due to lower contributions received from EIG in the 2018 period compared to the 2017 period as the first quarter of 2017 included $387 million we received from EIG for the sale of a 49% partnership interest in ELC; and
- a $250 million increase in cash used for common shares repurchased under our common share buy-back program in the 2018 period.

Dividends and Stock Buyback Program

KMI Common Stock Dividends

We expect to declare common stock dividends of $0.80 per share on our common stock for 2018.

Three months ended	Total quarterly dividend per share for the	Date of declaration	Date of record	Date of dividend

	period			
December 31, 2017	$ 0.125	January 17, 2018	January 31, 2018	February 15, 2018
March 31, 2018	$ 0.20	April 18, 2018	April 30, 2018	May 15, 2018

The actual amount of common stock dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. "Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business." of our 2017 Form 10-K. All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common stock dividends are not cumulative. Consequently, if dividends on our common stock are not paid at the intended levels, our common stockholders are not entitled to receive those payments in the future. Our common stock dividends generally are expected to be paid on or about the 15th day of each February, May, August and November.

KMI Preferred Stock Dividends

Dividends on our mandatory convertible preferred stock are payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.750% of the liquidation preference of $1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. We may pay dividends in cash or, subject to certain limitations, in shares of common stock or any combination of cash and shares of common stock. The terms of the mandatory convertible preferred stock provide that, unless full cumulative dividends have been paid or set aside for payment on all outstanding mandatory convertible preferred stock for all prior dividend periods, no dividends may be declared or paid on common stock.

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
October 26, 2017 through January 25, 2018	$ 24.375	October 18, 2017	January 11, 2018	January 26, 2018
January 26, 2018 through April 25, 2018	$ 24.375	January 18, 2018	April 11, 2018	April 26, 2018

The cash dividend of $24.375 per share of our mandatory convertible preferred stock is equivalent to $1.21875 per depository share.

Stock Buyback Program

On July 19, 2017, our board of directors approved a $2 billion share buyback program that began in December 2017. In the first quarter of 2018, we repurchased approximately 13 million of our Class P shares for approximately $250 million.

Noncontrolling Interests

KML Distributions

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its distributable cash flow. The payment of dividends is not guaranteed, and the amount and timing of any dividends payable will be at the discretion of KML's board of directors. KML intends to pay quarterly dividends, if any, on or about the 45th day (or next business day) following the end of each calendar quarter to holders of its restricted voting shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter.

For 2018, KML previously announced that it expects to pay a dividend of C$0.65 per restricted voting share.

KML Dividends on its Series 1 Preferred Shares and Series 3 Preferred Shares

KML also pays dividends on its 12,000,000 Series 1 Preferred Shares and 10,000,000 Series 3 Preferred Shares, which are fixed, cumulative, preferential, and payable quarterly in the annual amount of C$1.3125 per share and C$1.3000 per share, respectively, on the 15th day of February, May, August and November, as and when declared by KML's board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2017, in Item 7A in our 2017 Form 10-K. For more information on our risk management activities, see Item 1, Note 4 “Risk Management” to our consolidated financial statements.

Item 4. Controls and Procedures.

As of March 31, 2018, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended March 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 9 to our consolidated financial statements entitled “Litigation, Environmental and Other Contingencies” which is incorporated in this item by reference.

Item 1A. Risk Factors.

There have been no material changes in the risk factors disclosed in Part I, Item 1A in our 2017 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Our Purchases of Our Class P Shares

Period	Total number of securities purchased(a)	Average price paid per security	Total number of securities purchased as part of publicly announced plans(a)	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs
January 1 to January 31, 2018	11,054,400	$ 19.01	11,054,400	$ 1,539,786,059
February 1 to February 28, 2018	2,175,738	$ 18.28	2,175,738	$ 1,500,000,715
March 1 to March 31, 2018	—	$ —	—	$ 1,500,000,715
Total	13,230,138	$ 18.89	13,230,138	$ 1,500,000,715

(a) On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. After repurchase, the shares are cancelled and no longer outstanding.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

The Company no longer owns or operates mines for which reporting requirements apply under the mine safety disclosure requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), except for one terminal that is in temporary idle status with the Mine Safety and Health Administration. The Company has not received any specified health and safety violations, orders or citations, related assessments or legal actions, mining-related fatalities, or similar events requiring disclosure pursuant to the mine safety disclosure requirements of Dodd-Frank for the quarter ended March 31, 2018.

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit Number	Description
4.1	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 4.300% Senior Notes due 2028 and the 5.200% Senior Notes due 2048.
10.1	Cross Guarantee Agreement, dated as of November 26, 2014, among Kinder Morgan, Inc. and certain of its subsidiaries, with schedules updated as of March 31, 2018.
12.1	Statement re: computation of ratio of earnings to fixed charges.
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three months ended March 31, 2018 and 2017; (ii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2018 and 2017; (iii) our Consolidated Balance Sheets as of March 31, 2018 and December 31, 2017; (iv) our Consolidated Statements of Cash Flows for the three months ended March 31, 2018 and 2017; (v) our Consolidated Statements of Stockholders’ Equity for the three months ended March 31, 2018 and 2017; and (vi) the notes to our Consolidated Financial Statements.

SIGNATURE

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.

KINDER MORGAN, INC.
Registrant

Date:	April 23, 2018	By:	/s/ David P. Michels
			David P. Michels
			Vice President and Chief Financial Officer
			(principal financial and accounting officer)

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