KINDER MORGAN, INC.
Form 10-Q
July 20, 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 June 30, 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 July 19, 2018, the registrant had 2,206,828,970 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

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

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.

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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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Natural gas sales	$727	$758	$1,554	$1,567
Services	1,984	1,940	3,951	3,917
Product sales and other	717	670	1,341	1,308
Total Revenues	3,428	3,368	6,846	6,792
Operating Costs, Expenses and Other				
Costs of sales	1,068	1,070	2,087	2,131
Operations and maintenance	617	556	1,236	1,089
Depreciation, depletion and amortization	571	577	1,141	1,135
General and administrative	164	157	337	341
Taxes, other than income taxes	85	91	173	195
Loss on impairments and divestitures, net	653	—	653	6
Other income, net	(2)	(1)	(2)	—
Total Operating Costs, Expenses and Other	3,156	2,450	5,625	4,897
Operating Income	272	918	1,221	1,895
Other Income (Expense)				
Earnings from equity investments	328	135	548	310
Loss on impairment of equity investment	(270)	—	(270)	—
Amortization of excess cost of equity investments	(24)	(15)	(56)	(30)
Interest, net	(516)	(463)	(983)	(928)
Other, net	34	24	70	43
Total Other Expense	(448)	(319)	(691)	(605)
(Loss) Income Before Income Taxes	(176)	599	530	1,290
Income Tax Benefit (Expense)	46	(216)	(118)	(462)
Net (Loss) Income	(130)	383	412	828
Net Income Attributable to Noncontrolling Interests	(11)	(7)	(29)	(12)
Net (Loss) Income Attributable to Kinder Morgan, Inc.	(141)	376	383	816
Preferred Stock Dividends	(39)	(39)	(78)	(78)
Net (Loss) Income Available to Common Stockholders	$(180)	$337	$305	$738

Class P Shares				
Basic and Diluted (Loss) Earnings Per Common Share	$(0.08)	$0.15	$0.14	$0.33
Basic and Diluted Weighted Average Common Shares Outstanding	2,204	2,230	2,206	2,230
Dividends Per Common Share Declared for the Period	$0.20	$0.125	$0.40	$0.25

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net (loss) income	$(130)	$383	$412	$828
Other comprehensive (loss) income, net of tax				
Change in fair value of hedge derivatives (net of tax benefit (expense) of $24, $(63), $13 and $(102), respectively)	(80)	108	(46)	178
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(24), $43, $(19) and $55, respectively)	83	(75)	67	(96)
Foreign currency translation adjustments (net of tax benefit (expense) of $9, $(10), $21 and $(17), respectively)	(48)	38	(113)	51
Benefit plan adjustments (net of tax expense of $2, $4, $4 and $9, respectively)	6	7	12	13
Total other comprehensive (loss) income	(39)	78	(80)	146
Comprehensive (loss) income	(169)	461	332	974
Comprehensive loss (income) attributable to noncontrolling interests	5	(26)	11	(31)
Comprehensive (loss) income attributable to Kinder Morgan, Inc.	$(164)	$435	$343	$943

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)

	June 30, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 271	$ 264
Restricted deposits	76	62
Accounts receivable, net	1,357	1,448
Fair value of derivative contracts	93	114
Inventories	420	424
Income tax receivable	163	165
Other current assets	254	238
Total current assets	2,634	2,715
Property, plant and equipment, net	39,905	40,155
Investments	7,293	7,298
Goodwill	22,153	22,162
Other intangibles, net	2,989	3,099
Deferred income taxes	1,953	2,044
Deferred charges and other assets	1,388	1,582
Total Assets	$ 78,315	$ 79,055
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of debt	$ 2,132	$ 2,828
Accounts payable	1,269	1,340
Accrued interest	584	621
Accrued contingencies	306	291
Other current liabilities	1,088	1,101
Total current liabilities	5,379	6,181
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	34,640	33,988
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	626	927
Total long-term debt	35,366	35,015
Other long-term liabilities and deferred credits	2,495	2,735
Total long-term liabilities and deferred credits	37,861	37,750
Total Liabilities	43,240	43,931
Commitments and contingencies (Notes 4 and 11)		
Redeemable Noncontrolling Interest	581	—
Stockholders' Equity		
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	—	—
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,203,969,844 and 2,217,110,072 shares, respectively, issued and outstanding	22	22

Additional paid-in capital	41,696	41,909
Retained deficit	(7,993)	(7,754)
Accumulated other comprehensive loss	(690)	(541)
Total Kinder Morgan, Inc.'s stockholders' equity	33,035	33,636
Noncontrolling interests	1,459	1,488
Total Stockholders' Equity	34,494	35,124
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 78,315	$ 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)

	Six Months Ended June 30,	
	2018	2017
Cash Flows From Operating Activities		
Net income	$412	$828
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	1,141	1,135
Deferred income taxes	102	454
Amortization of excess cost of equity investments	56	30
Change in fair market value of derivative contracts	139	(5)
Loss on impairments and divestitures, net	653	6
Loss on impairment of equity investment	270	—
Earnings from equity investments	(548)	(310)
Distributions from equity investment earnings	237	208
Changes in components of working capital		
Accounts receivable, net	116	185
Inventories	6	(93)
Other current assets	(21)	—
Accounts payable	(77)	(59)
Accrued interest, net of interest rate swaps	(26)	(44)
Accrued contingencies and other current liabilities	(112)	(96)
Rate reparations, refunds and other litigation reserve adjustments	31	(35)
Other, net	89	(38)
Net Cash Provided by Operating Activities	2,468	2,166
Cash Flows From Investing Activities		
Acquisitions of assets and investments	(20)	(4)
Capital expenditures	(1,473)	(1,336)
Proceeds from sales of equity investments	33	—
Sales of property, plant and equipment, and other net assets, net of removal costs	6	71
Contributions to investments	(111)	(548)
Distributions from equity investments in excess of cumulative earnings	149	214
Loans to related party	(16)	(7)
Net Cash Used in Investing Activities	(1,432)	(1,610)
Cash Flows From Financing Activities		
Issuances of debt	8,565	4,330
Payments of debt	(8,575)	(6,124)
Debt issue costs	(31)	(60)
Cash dividends - common shares	(719)	(560)
Cash dividends - preferred shares	(78)	(78)
Repurchases of common shares	(250)	—
Contributions from investment partner	97	415
Contributions from noncontrolling interests - net proceeds from KML IPO	—	1,247
Contributions from noncontrolling interests - other	17	11

Distributions to noncontrolling interests	(35)	(15)
Other, net	(1)	(1)
Net Cash Used in Financing Activities	(1,010)	(835)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	(5)	10
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	21	(269)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	$347	$518
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	271	452
Restricted Deposits, end of period	76	66
Cash, Cash Equivalents, and Restricted Deposits, end of period	347	518
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	$21	$(269)

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

	Six Months Ended June 30,	
	2018	2017
Non-cash Investing and Financing Activities		
Increase in property, plant and equipment from both accruals and contractor retainage	$33	$159
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$954	$995
Cash paid during the period for income taxes, net	18	1

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)						175	(109)	66		66
Balance at January 1, 2018	2,217	22	2	—	41,909	(7,579)	(650)	33,702	1,488	35,190
Repurchase of shares	(13)				(250)			(250)		(250)
Restricted shares					37			37		37
Net income						383		383	29	412
Distributions								—	(44)	(44)
Contributions								—	26	26
Preferred stock dividends						(78)		(78)		(78)
Common stock dividends						(719)		(719)		(719)
Other comprehensive income							(40)	(40)	(40)	(80)
Balance at June 30, 2018	2,204	$ 22	2	$ —	$ 41,696	$ (7,993)	$ (690)	$ 33,035	$ 1,459	$ 34,494

	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					37			37		37
Net income						816		816	12	828
KML IPO					316		51	367	683	1,050
Distributions								—	(15)	(15)
Contributions								—	11	11
Preferred stock dividends						(78)		(78)		(78)
Common stock dividends						(560)		(560)		(560)
Impact of adoption of ASU 2016-09						9		9		9
Other								—	(16)	(16)
Other comprehensive income							127	127	19	146
Balance at June 30, 2017	2,230	$ 22	2	$ —	$ 42,092	$ (6,482)	$ (483)	$ 35,149	$ 1,065	$ 36,214

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.

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 8.

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 $37 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 $66 million in “Cash, Cash Equivalents, and Restricted Deposits, end of period” in our accompanying consolidated statement of cash flows for the six months ended June 30, 2017 from what was previously presented in our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 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 $66 million, net of income taxes, adjustment to our “Retained deficit” balance as presented in our consolidated statement of stockholders’ equity for the six months ended June 30, 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 June 30, 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 $4 million and $7 million of other components of net benefit credits (excluding the service cost component) from “General and administrative” to “Other, net” in our accompanying consolidated statement of income for the three and six months ended June 30, 2017, respectively. 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.” Our accounting policy for the release of stranded tax effects in accumulated other comprehensive income is on an aggregate portfolio basis. 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 six months ended June 30, 2018.

Impairments and Losses on Divestitures, net

During the three and six months ended June 30, 2018, we recognized (i) a $600 million non-cash impairment loss associated with certain gathering and processing assets in Oklahoma within our Natural Gas Pipelines business segment; (ii) a $60 million non-cash impairment related to certain Terminal business segment assets; (iii) a non-cash impairment of $270 million of our equity investment in Gulf LNG Holdings Group, LLC (Gulf LNG); and (iv) a gain of $7 million related to miscellaneous asset disposals.

During the six months ended June 30, 2017, we recorded losses on impairments and divestitures netting to $6 million related to miscellaneous asset disposals.

The $600 million non-cash impairment was driven by reduced cash flow estimates for some of our gathering and processing assets in Oklahoma during the period as a result of our decision to redirect our focus to other areas of our portfolio. These reduced estimates triggered an impairment analysis as we determined that our carrying value may no longer be recoverable. The impairment analysis for long-lived assets was based upon a two-step process as prescribed in the accounting standards. Step 1 involved comparing the undiscounted future cash flows to be derived from the asset group to the carrying value of the asset group. Based on the results of our step 1 test, we determined that the undiscounted future cash flows were less than the carrying value of the asset group. Step 2 involved using the income approach to calculate the fair value of the asset group and comparing it to the carrying value. The impairment that we recorded represented the difference between the fair and carrying values.

The $270 million non-cash impairment in our equity investment in Gulf LNG was driven by a ruling by an arbitration panel affecting a customer contract. Our share of earnings recognized by Gulf LNG on the respective customer contract is included in “Earnings from equity investments” in the accompanying consolidated statements of income for three and six months ended June 30, 2018.

The estimate of fair value is based on Level 3 valuation estimates using industry standard income approach valuation methodologies, which include assumptions primarily involving management’s significant judgments and estimates with respect to general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding commodity prices, future cash flows based on rate and volume assumptions, terminal values and discount rates. We typically use discounted cash flow analyses to determine the fair value of our assets. We may probability weight various forecasted cash flow scenarios utilized in the analysis as we consider the possible outcomes. We use discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular asset.

We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill. Because certain assets and investments have been written down to fair value in the last few years, any deterioration in fair value relative to our carrying value increases the likelihood of further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to be not fully recoverable.

Goodwill

In addition to periodically evaluating long-lived assets for impairment based on changes in market conditions as discussed above, we evaluate goodwill for impairment on May 31 of each year. For this purpose, we have seven reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO_2; (vi) Terminals; and (vii) Kinder Morgan Canada. The evaluation of goodwill for impairment involves a two-step test.

The results of our May 31, 2018 annual step 1 impairment test indicated that for each of our reporting units, the reporting unit fair value exceeded the carrying value, and step 2 was not required. A new period of volatile commodity prices could result in a deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital and our cash flow estimates. Changes to any one or combination of these factors would result in a change to the reporting unit fair values discussed above, which could lead to future impairment charges. Such potential impairment could have a material effect on our results of operations.

The fair value estimates used in step 1 of the goodwill test are based on Level 3 inputs of the fair value hierarchy. The level 3 inputs include valuation estimates using industry standard market and income approach valuation methodologies which include assumptions primarily involving management’s significant judgments and estimates with respect to market multiples, comparable sales transactions prices, weighted average costs of capital, general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding commodity prices, future cash flows based on rate and volume assumptions, terminal values and discount rates. We use primarily a market approach and, in some instances where deemed necessary, also use discounted cash flow analyses to determine the fair value of our assets. We use discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular reporting unit.

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net (Loss) Income Available to Common Stockholders	$(180)	$337	$305	$738
Participating securities:				
Less: Net Income Allocated to Restricted stock awards(a)	(2)	(1)	(3)	(3)
Net (Loss) Income Allocated to Class P Stockholders	$(182)	$336	$302	$735
Basic Weighted Average Common Shares Outstanding	2,204	2,230	2,206	2,230
Basic (Loss) Earnings Per Common Share	$(0.08)	$0.15	$0.14	$0.33

(a) As of June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Unvested restricted stock awards	10	9	10	9
Warrants to purchase our Class P shares(a)	—	—	—	233
Convertible trust preferred securities	3	3	3	3
Mandatory convertible preferred stock(b)	58	58	58	58

(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. Divestitures

Pending Sale of Trans Mountain Pipeline System and Its Expansion Project

On May 29, 2018, KML announced that the Government of Canada has agreed to purchase from KML the TMPL, the TMEP, Puget Sound pipeline system and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business and assets to be sold, for C$4.5 billion (the “Transaction”), subject to certain adjustments as provided in the share and unit purchase agreement (the “Purchase Agreement”).

As part of the Purchase Agreement, the Government of Canada has agreed to fund the resumption of the TMEP planning and construction work by guaranteeing TMEP's borrowings under a separately created temporary credit facility for such expenditures until the Transaction closes. (See Note 4 for information on KML’s temporary credit facilities).

The Transaction is expected to close late in the third quarter or early in the fourth quarter of 2018, subject to KML's shareholder and applicable regulatory approvals. The assets to be sold will be classified as assets held for sale upon KML shareholder approval, and the Transaction is expected to result in a gain. The use of proceeds from the sale of the TMPL and the TMEP is a KML board decision. We intend to use any proceeds we receive in respect of our interest in KML to pay down debt.

May 2017 Sale of Approximate 30% Interest in Canadian Business

On May 30, 2017, KML completed an IPO of 102,942,000 restricted voting shares listed on the Toronto Stock Exchange at a price to the public of C$17.00 per restricted voting share for total gross proceeds of approximately C$1,750 million (US$1,299 million). The net proceeds from the IPO were used by KML to indirectly acquire from us an approximate 30% interest in a limited partnership that holds our Canadian business while we retained the remaining 70% interest. We used the proceeds from KML's IPO to pay down debt.

February 2017 Sale of Noncontrolling Interest in ELC

Effective February 28, 2017, we sold a 49% partnership interest in ELC to investment funds managed by EIG Global Energy Partners (EIG). We continue to own a 51% controlling interest in and operate ELC. Under the terms of ELC's limited liability company agreement, we are responsible for placing in service and operating certain supply pipelines and terminal facilities that support the operations of ELC and that are wholly owned by us. In certain limited circumstances that are not expected to occur, EIG has the right to relinquish its interest in ELC and redeem its capital account. The sale proceeds of $386 million, and subsequent EIG contributions, have been reflected as of June 30, 2018 within "Redeemable Noncontrolling Interest" and as of December 31, 2017 as a deferred credit within "Other long-term liabilities and deferred credits", respectively, on our consolidated balance sheets. Once these contingencies expire, EIG's capital account will be reflected in "Noncontrolling interests" on our consolidated balance sheet.

3. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. Summarized combined financial information for our single significant equity investment is reported below (in millions; amounts represent 100% of investee financial information):

	Six Months Ended June 30,	
Income Statement	2018	2017
Revenues	$456	$ 93
Costs and expenses	53	46
Net Income	$403	$ 47
Our share of net income	$202	$ 23

For additional information regarding our equity investments, see Note 7 to our consolidated financial statements included in our 2017 Form 10-K.

4. 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 additional information 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):

	June 30, 2018	December 31, 2017
Current portion of debt		
Credit facility due November 26, 2019, 3.37% and 2.83%, respectively(a)	$350	$ 125
Commercial paper notes, 2.59% and 1.95%, respectively(a)	140	240
KML 2018 Credit Facility, 2.86%(a)(b)(c)	101	—
TMPL Non-recourse Credit Agreement, 1.98%(a)(b)	87	—
Current portion of senior notes		
6.00%, due January 2018	—	750
7.00%, due February 2018	—	82
5.95%, due February 2018	—	975
7.25%, due June 2018	—	477
9.00%, due February 2019	500	—
2.65%, due February 2019	800	—
Trust I preferred securities, 4.75%, due March 2028	111	111
Current portion - Other debt	43	68
Total current portion of debt	2,132	2,828
Long-term debt (excluding current portion)		
Senior notes	33,907	33,248
EPC Building, LLC, promissory note, 3.967%, due 2017 through 2035	402	409
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock	100	100
Trust I preferred securities, 4.75%, due March 2028	110	110
Other	221	221
Total long-term debt	34,740	34,088
Total debt(d)	$36,872	$ 36,916

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(a) Interest rates are weighted average rates.

(b) Balances outstanding under the KML 2018 Credit Facility are denominated in C$ and have been converted to U.S. dollars and reported above at the June 30, 2018 exchange rate of 0.7594 U.S. dollars per C$. See "—Credit Facilities" below.

(c) Weighted average interest rates are based on interest expense denominated in C$.

(d) Excludes our "Debt fair value adjustments" which, as of June 30, 2018 and December 31, 2017, increased our combined debt balances by $626 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 13.

Credit Facilities

KMI

As of June 30, 2018, we had $350 million outstanding under our credit facility, $140 million outstanding under our commercial paper program and $99 million in letters of credit. Our availability under our $5 billion credit facility as of June 30, 2018 was $4,411 million. As of June 30, 2018, we were in compliance with all required covenants.

KML

Pursuant to the Transaction described in Note 2, on May 30, 2018, approximately C$100 million of borrowings outstanding under KML's June 16, 2017 revolving credit facilities (the "KML 2017 Credit Facility") were repaid, the underlying credit

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facilities were terminated, and we wrote off approximately $46 million of deferred costs associated with the KML 2017 Credit Facility that were being amortized as interest expense over its term.

On May 30, 2018 and concurrently with the termination of the KML 2017 Credit Facility, KML completed a credit agreement with Royal Bank of Canada, as administrative agent, and the lenders party thereto (the “KML 2018 Credit Agreement”) establishing a C$500 million revolving credit facility (the “KML 2018 Credit Facility”), for general corporate purposes, including working capital. The approximate C$100 million of borrowings outstanding under the terminated KML 2017 Credit Facility were repaid pursuant to an initial drawdown under the KML 2018 Credit Facility.

The KML 2018 Credit Facility will mature on the earlier of (i) the date of the closing of the Transaction or (ii) May 29, 2020. Depending on the type of loan requested by us, interest on loans outstanding will be calculated based on (i) a Canadian prime rate of interest plus 0.20% per annum; (ii) a U.S. base rate of interest plus 0.20% per annum; (iii) London Interbank Offered Rate (LIBOR) plus 1.20% per annum; or (iv) bankers’ acceptance fees and 1.20% per annum. Standby fees for the unused portion of the KML 2018 Credit Facility will be calculated based on a rate of 0.24% per annum.

The KML 2018 Credit Agreement contains various financial and other covenants that apply to KML and its subsidiaries and that are common in such agreements, including a maximum ratio of KML’s consolidated total funded debt to its consolidated capitalization of 70% and restrictions on KML’s ability to incur debt, grant liens, make dispositions (although the Transaction is specifically permitted), engage in transactions with affiliates, make restricted payments, make investments, enter into sale leaseback transactions, amend organizational documents and engage in corporate reorganization transactions.

In addition, the KML 2018 Credit Agreement contains customary events of default, including non-payment; non-compliance with covenants (in some cases, subject to grace periods); payment default under, or acceleration events affecting, certain other indebtedness; bankruptcy or insolvency events involving KML or guarantors; and changes of control. If an event of default under the KML 2018 Credit Agreement exists and is continuing, the lenders could terminate their commitments and accelerate the maturity of the outstanding obligations under the KML 2018 Credit Agreement.

On June 14, 2018, KML’s and our subsidiary, TMPL, as the borrower, entered into new, non-revolving, unsecured construction credit agreement (the “TMPL Non-recourse Credit Agreement”) among TMPL, Royal Bank of Canada (“RBC”), as administrative agent (“Agent”), and The Toronto-Dominion Bank (together with RBC, the “Lenders”) in an aggregate principal amount of up to approximately C$1 billion to facilitate the resumption of the TMEP planning and construction work until the closing of the Transaction. The TMPL Non-recourse Credit Agreement provides for a maturity date on the earliest to occur of (i) completion of the Transaction or another disposition of KML’s interest in the entities or material assets that are subject to the Transaction; (ii) termination of the Purchase Agreement; (iii) assignment by KML of its rights and obligations under the Purchase Agreement; or (iv) December 31, 2018.

The payment obligations of TMPL to the Agent and the Lenders under the TMPL Non-recourse Credit Agreement are guaranteed by Her Majesty in Right of Canada (“TMPL Non-recourse Credit Agreement Guarantor”) pursuant to an unconditional and irrevocable guarantee (“TMPL Non-recourse Credit Agreement Guarantee”). The TMPL Non-recourse Credit Agreement is non-recourse to TMPL, its subsidiaries, KML or KMI, or any of their respective property, assets and undertakings; the Agent and the Lenders’ sole recourse is to the TMPL Non-recourse Credit Agreement Guarantor under the TMPL Non-recourse Credit Agreement Guarantee.

In connection with the TMPL Non-recourse Credit Agreement and the TMPL Non-recourse Credit Agreement Guarantee, TMPL’s, KML’s and our subsidiary, Kinder Morgan Cochin ULC (“KMCU”), entered into an indemnity agreement (the “Indemnity Agreement”) in favor of the TMPL Non-recourse Credit Agreement Guarantor obligating

TMPL to reimburse and indemnify the TMPL Non-recourse Credit Agreement Guarantor for amounts paid under and pursuant to the TMPL Non-recourse Credit Agreement Guarantee in certain very limited circumstances. In addition, the Indemnity Agreement includes, for the benefit of the TMPL Non-recourse Credit Agreement Guarantor, limited rights to indemnification in the event of inaccuracies in certain representations, or the failure of KMCU to perform certain covenants, under the Purchase Agreement. Except for the indemnities referred to in this paragraph and certain other limited exceptions, the TMPL Non-recourse Credit Agreement Guarantor has no recourse to TMPL or KMCU under the Indemnity Agreement.

As security for TMPL's and KMCU's limited recourse obligations under the Indemnity Agreement, TMPL and its subsidiaries granted second ranking security in favor of the TMPL Non-recourse Credit Agreement Guarantor against their respective assets, and KMCU granted a limited recourse pledge of its equity in TMPL and the general partner thereof.

As of June 30, 2018, KML had C$313 million (U.S. $238 million) available under the KML 2018 Credit Facility, after reducing the C$500 million (U.S.$380 million) capacity for the C$133.0 million (U.S.$101 million) outstanding borrowings and the C$54 million (U.S.$41 million) in letters of credit. As of June 30, 2018, KML was in compliance with all required covenants. As of December 31, 2017, KML had no borrowings outstanding under the KML 2017 Credit Facility.

As of June 30, 2018, TMPL had C$886 million (U.S.$672 million) available under the TMPL Non-Recourse Credit Agreement, after reducing the approximate C$1 billion (U.S.$759 million) in aggregate capacity for the C$114 million (U.S.$87 million) outstanding under this credit facility. As of June 30, 2018, TMPL was in compliance with all its required covenants.

5. Stockholders' Equity

Common Equity

As of June 30, 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 six months ended June 30, 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Per common share cash dividend declared for the period	$0.20	$0.125	$0.40	$0.25
Per common share cash dividend paid in the period	$0.20	$0.125	$0.325	$0.25

On July 18, 2018, our board of directors declared a cash dividend of $0.20 per common share for the quarterly period ended June 30, 2018, which is payable on August 15, 2018 to common shareholders of record as of the close of business on July 31, 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 April 18, 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 April 26, 2018 through and including July 25, 2018, which is payable on July 26, 2018 to mandatory convertible preferred shareholders of record as of the close of business on July 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.

During the three and six months ended June 30, 2018, KML paid dividends on its Restricted Voting Shares to the public valued at$13 million and $26 million, respectively, of which $8 million and $18 million, respectively, were paid in cash. The remaining values of $5 million and $8 million for the three and six months ended June 30, 2018, respectively, were paid in

362,158 and 656,555 KML Restricted Voting Shares, respectively. KML also paid dividends to the public on its Series 1 and Series 3 Preferred Shares of $6 million and $10 million for the three and six months ended June 30, 2018, respectively.

6. 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.

During the three months ended June 30, 2018, due to volatility in certain basis differentials, we discontinued hedge accounting on certain of our crude derivative contracts as we do not expect them to be highly effective, for accounting purposes, in offsetting the variability in cash flows. As the forecasted transactions are still probable, accumulated gains and losses remain in other comprehensive income until earnings are impacted by the forecasted transactions. Future changes in the derivative contracts' fair value subsequent to the discontinuance of hedge accounting will be reported in earnings. We may re-designate certain of these hedging relationships if their expected effectiveness improves.

Energy Commodity Price Risk Management

As of June 30, 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	(12.9)	MMBbl
Crude oil basis	(7.9)	MMBbl
Natural gas fixed price	(43.3)	Bcf
Natural gas basis	(35.1)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(10.3)	MMBbl
Natural gas fixed price	(1.9)	Bcf
Natural gas basis	(13.2)	Bcf
NGL fixed price	(3.9)	MMBbl

As of June 30, 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 June 30, 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 LIBOR plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of June 30, 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 June 30, 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	
		June 30, 2018	December 31, 2017	June 30, 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)	$71	$ 65	$(91)	$ (53)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	14	(44)	(24)
Subtotal		71	79	(135)	(77)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	19	41	(27)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	89	164	(195)	(62)
Subtotal		108	205	(222)	(65)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(20)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	169	166	—	—
Subtotal		169	166	(20)	(6)
Total		348	450	(377)	(148)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	3	8	(64)	(22)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	1	—	(39)	(2)
Total		4	8	(103)	(24)
Total derivatives		$352	$ 458	$(480)	$ (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 June 30,		Six Months Ended June 30,	
		2018	2017	2018	2017
Interest rate swap agreements	Interest, net	$(81)	$46	$(254)	$7
Hedged fixed rate debt	Interest, net	$77	$(47)	$245	$(11)

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 June 30,			Three Months Ended June 30,			Three Months Ended June 30,	
	2018	2017		2018	2017		2018	2017
Energy commodity derivative contracts	$(23)	$52	Revenues—Natural gas sales	$ (5)	$ (1)	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	(13)	14	Revenues—Product sales and other	(56)	5
			Costs of sales	—	1	Costs of sales	—	—
Interest rate swap agreements(c)	1	(1)	Earnings from equity investments	(3)	(1)	Earnings from equity investments	—	—
Cross-currency swap	(58)	57	Other, net	(62)	62	Other, net	—	—
Total	$(80)	$108	Total	$ (83)	$ 75	Total	$ (56)	$ 5

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)
	Six Months Ended June		Six Months Ended June 30,		Six Months Ended June 30,

	30, 2018	2017		2018	2017		2018	2017
Energy commodity derivative contracts	$(40)	$120	Revenues—Natural gas sales	$ (5)	$ 1	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	(27)	20	Revenues—Product sales and other	(85)	8
			Costs of sales	—	4	Costs of sales	—	—
Interest rate swap agreements(c)	2	(1)	Earnings from equity investments	(4)	(1)	Earnings from equity investments	—	—
Cross-currency swap	(8)	59	Other, net	(31)	72	Other, net	—	—
Total	$(46)	$178	Total	$ (67)	$ 96	Total	$ (85)	$ 8

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(a) We do not expect to reclassify any gain or loss associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of June 30, 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) During the three and six months ended June 30, 2018, we recognized a $3 million loss as a result of our equity investment's forecasted transactions being probable of not occurring. All other 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 June 30,		Six Months Ended June 30,	
		2018	2017	2018	2017
Energy commodity derivative contracts	Revenues—Natural gas sales	$ (1)	$ 5	$ 2	$ 11
	Revenues—Product sales and other	(45)	7	(46)	19
	Costs of sales	1	—	1	—
Total(a)		$ (45)	$ 12	$ (43)	$ 30

(a) The three and six months ended June 30, 2018 include an approximate loss of $5 million and gain of $3 million, respectively, and the three and six months ended June 30, 2017 include approximate gains of $17 million and $29 million, respectively. These gains and losses were 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 June 30, 2018 and December 31, 2017, we had no outstanding letters of credit supporting our commodity price risk management program. As of June 30, 2018 and December 31, 2017, we had cash margins of $23 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 June 30, 2018 consisted of initial margin requirements of $10 million and variation margin requirements of $13 million. We also use industry standard commercial agreements that 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 June 30, 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 $100 million of additional collateral and $9 million of additional collateral beyond this $100 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	(46)	(73)	12	(107)
Gains reclassified from accumulated other comprehensive loss	67	—	—	67
Impact of adoption of ASU 2018-02 (Note 1)	(4)	(36)	(69)	(109)
Net current-period other comprehensive income (loss)	17	(109)	(57)	(149)
Balance as of June 30, 2018	$ (10)	$ (298)	$ (382)	$ (690)

	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	178	32	13	223
Gains reclassified from accumulated other comprehensive loss	(96)	—	—	(96)
KML IPO	—	44	7	51
Net current-period other comprehensive income	82	76	20	178
Balance as of June 30, 2017	$ 81	$ (212)	$ (352)	$ (483)

7. 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 June 30, 2018							
Energy commodity derivative contracts(a)	$2	$73	$ —	$ 75	$(30)	$ —	$ 45
Interest rate swap agreements	—	108	—	108	(10)	—	98
Cross-currency swap agreements	—	169	—	169	(20)	—	149
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 June 30, 2018							
Energy commodity derivative contracts(a)	$(6)	$(232)	$ —	$(238)	$30	$ 13	$(195)
Interest rate swap agreements	—	(222)	—	(222)	10	—	(212)
Cross-currency swap agreements	—	(20)	—	(20)	20	—	—
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):

June 30, 2018 December 31, 2017

	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$37,498	$ 38,344	$37,843	$ 40,050

We used Level 2 input values to measure the estimated fair value of our outstanding debt balances as of both June 30, 2018 and December 31, 2017.

8. 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 that 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 June 30, 2018			Six Months Ended June 30, 2018		
Line Item	As Reported	Amounts Without Adoption of Topic 606	Effect of Change Increase/(Decrease)	As Reported	Amounts Without Adoption of Topic 606	Effect of Change Increase/(Decrease)
Consolidated Statement of Income						
Natural gas sales	$727	$ 737	$ (10)	$1,554	$ 1,578	$ (24)
Services	1,984	2,036	(52)	3,951	4,048	(97)
Product sales and other	717	789	(72)	1,341	1,500	(159)
Total Revenues	3,428	3,562	(134)	6,846	7,126	(280)
Cost of sales	1,068	1,202	(134)	2,087	2,367	(280)
Operating Income	272	272	—	1,221	1,221	—

The effect-of-change amounts in the table above are attributable to the non-FERC-regulated portion of our Natural Gas Pipelines business segment, 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) control of the goods or services transfers to the customer and 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 is a separate performance obligation, as our promise is to sell multiple distinct units of commodity 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 sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity's standalone selling price and recognized as revenue upon delivery of the commodity, which is the point in time when the customer obtains control of the commodity 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) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, 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 the beginning of 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 the beginning of 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 non-refundable 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. Under firm service contracts, 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 tables present our revenues disaggregated by revenue source and type of revenue for each revenue source (in millions):

	Three Months Ended June 30, 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)	$784	$—	$ 261	$ 147	$ —	$ (4)	$1,188
Fee-based services	202	16	152	198	62	—	630
Total services revenues	986	16	413	345	62	(4)	1,818
Sales							
Natural gas sales	735	1	—	—	—	(2)	734
Product sales	381	318	4	60	—	—	763
Other sales	2	—	—	—	—	—	2
Total sales revenues	1,118	319	4	60	—	(2)	1,499
Total revenues from contracts with customers	2,104	335	417	405	62	(6)	3,317
Other revenues(b)	62	(85)	96	37	3	(2)	111
Total revenues	$2,166	$250	$ 513	$ 442	$ 65	$ (8)	$3,428

	Six Months Ended June 30, 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)	$1,587	$1	$ 515	$ 285	$ —	$ (8)	$2,380
Fee-based services	405	33	296	381	126	1	1,242
Total services revenues	1,992	34	811	666	126	(7)	3,622
Sales							
Natural gas sales	1,561	1	—	—	—	(4)	1,558
Product sales	638	635	6	108	—	—	1,387
Other sales	4	—	—	—	—	—	4
Total sales revenues	2,203	636	6	108	—	(4)	2,949
Total revenues from contracts with customers	4,195	670	817	774	126	(11)	6,571
Other revenues(b)	137	(116)	189	67	—	(2)	275
Total revenues	$4,332	$554	$ 1,006	$ 841	$ 126	$ (13)	$6,846

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(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. 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 6 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. Our contract assets are substantially related to breakage revenue associated with our firm service contracts with minimum volume commitment payment obligations and contracts where we apply revenue levelization (i.e., contracts with fixed rates per volume that increase over the life of the contract for which we record revenue ratably per unit over the life of the contract based on our performance obligations that are generally unchanged over the life of the contract). 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; (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); and (iii) contracts with fixed rates per volume that decrease over the life of the contract where we apply revenue levelization for amounts received for our future performance obligations.

The following table presents the activity in our contract assets and liabilities (in millions):

	Six Months Ended June 30, 2018
Contract Assets(a)	
Balance at December 31, 2017	$ 32
Additions	55
Transfer to Accounts receivable	(35)
Balance at June 30, 2018	$ 52
Contract Liabilities(b)	
Balance at December 31, 2017	$ 206
Additions	191
Transfer to Revenues	(153)
Other(c)	(4)
Balance at June 30, 2018	$ 240

(a) Includes current balances of $44 million and $25 million reported within “Other current assets” in our accompanying consolidated balance sheets at June 30, 2018 and December 31, 2017, respectively, and includes non-current balances of $8 million and $7 million reported within “Deferred charges and other assets” in our accompanying consolidated balance sheets at June 30, 2018 and December 31, 2017, respectively.

(b) Includes current balances of $77 million and $79 million reported within “Other current liabilities” in our accompanying consolidated balance sheets at June 30, 2018 and December 31, 2017, respectively, and includes non-current balances of $163 million and $127 million reported within "Other long-term liabilities and deferred credits" in our accompanying consolidated balance sheets at June 30, 2018 and December 31, 2017, respectively.

(c) Includes 2018 foreign currency translation adjustments associated with the balances at December 31, 2017.

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 June 30, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods (in millions):

Year	Estimated Revenue
Six months ended December 31, 2018	$ 2,467
2019	4,383
2020	3,652
2021	3,141
2022	2,671
Thereafter	14,292
Total	$ 30,606

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.

9. Reportable Segments

Financial information by segment follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Natural Gas Pipelines				
Revenues from external customers	$2,163	$2,093	$4,327	$4,261
Intersegment revenues	3	2	5	5
CO_2	250	307	554	610
Terminals				
Revenues from external customers	512	486	1,005	973
Intersegment revenues	1	1	1	1
Products Pipelines				
Revenues from external customers	438	413	834	811
Intersegment revenues	4	5	7	9
Kinder Morgan Canada	65	60	126	119
Corporate and intersegment eliminations(a)	(8)	1	(13)	3
Total consolidated revenues	$3,428	$3,368	$6,846	$6,792

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Segment EBDA(b)				
Natural Gas Pipelines	$313	$907	$1,449	$1,962
CO_2	157	221	356	439
Terminals	274	304	569	611
Products Pipelines	319	324	578	611
Kinder Morgan Canada	46	43	92	86
Total Segment EBDA	1,109	1,799	3,044	3,709
DD&A	(571)	(577)	(1,141)	(1,135)
Amortization of excess cost of equity investments	(24)	(15)	(56)	(30)
General and administrative and corporate charges	(174)	(145)	(334)	(326)
Interest, net	(516)	(463)	(983)	(928)
Income tax benefit (expense)	46	(216)	(118)	(462)
Total consolidated net (loss) income	$(130)	$383	$412	$828

	June 30, 2018	December 31, 2017
Assets		
Natural Gas Pipelines	$50,659	$ 51,173
CO_2	3,931	3,946
Terminals	9,754	9,935
Products Pipelines	8,511	8,539
Kinder Morgan Canada	2,267	2,080
Corporate assets(c)	3,193	3,382
Total consolidated assets	$78,315	$ 79,055

(a) Three and six month 2017 amounts include a management fee for services we perform as operator of an equity investee of $9 million and $18 million, respectively.

(b) Includes revenues, earnings from equity investments, other, net, less operating expenses, loss on impairments and divestitures, net, loss on impairment of equity investment and other (income) expense, net.

(c) Includes cash and cash equivalents, margin and restricted deposits, 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 our reportable segments.

10. Income Taxes

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Income tax (benefit) expense	$(46)	$216	$118	$462
Effective tax rate	26.1 %	36.1 %	22.3 %	35.8 %

The effective tax rate for the three months ended June 30, 2018 is higher than the statutory federal rate of 21% primarily due to the reduction in our reserves for uncertain tax positions as a result of the settlement of our 2011 - 2014 federal tax audit reducing our income tax expense.

The effective tax rate for the six months ended June 30, 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 investments in Florida Gas Transmission Company (Citrus) and Plantation Pipe Line and the reduction in our reserves for uncertain tax positions as a result of the settlement of our 2011 - 2014 federal tax audit.

The effective tax rate for the three and six months ended June 30, 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 investments 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 six months ended June 30, 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.

11. 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

FERC Rulemaking on Tax Cuts and Jobs Act for Jurisdictional Natural Gas Pipelines

On March 15, 2018, FERC issued a notice of proposed rule-making (NOPR) which proposed a process to implement for ratemaking purposes the 2017 Tax Reform. The NOPR proposed that each regulated interstate natural gas pipeline make a mandatory filing (Form 501-G) to reflect, based upon certain required assumptions, the rate impact of the reduced statutory corporate tax rate, and in the case of master limited partnerships and other pass-entities, the elimination of an income tax allowance and unspecified resulting treatment of accumulated deferred income tax (ADIT) in the cost of service. The Commission's NOPR also provided four options for regulated entities to consider: (1) make a limited filing under section 4 of the NGA to reduce rates for the impact of the 2017 Tax Reform; (2) commit to file a general section 4 rate case in the near future; (3) file an explanation why no rate change is needed, and (4) take no further action other than filing the required Form 501-G report. On July 18, 2018, FERC issued Order No. 849 (Final Rule) promulgating a final rule to implement the 2017 Tax Reform for jurisdictional natural gas pipelines. The Final Rule continues to require the regulated interstate pipelines to file the Form 501-G reflecting certain mandatory assumptions. The Final Rule also maintains substantially the same four options for a pipeline to choose between to implement the reduced corporate tax rate. The Final Rule does clarify that pass through entities whose income consolidates up to a federal income tax paying entity will be allowed to reflect an income tax allowance. It also clarifies that the required filing is a one-time informational filing and that FERC is not mandating any adjustment in rates as a function of complying with the Final Rule. Companies are also allowed to file an addendum which may reflect an income tax allowance, alternative capital structure and alternative equity returns. The Final Rule maintains the integrity of negotiated rate contracts. We believe that the required, one-time, informational Form 501-G filings will be misleading and confusing to customers and investors. We also continue to believe any negative impact to revenues will be mitigated and spread out over multiple years given the procedural options presented in the Final Rule, the prospective nature of rate changes under section 5 of the NGA and the fact that the Commission affirmed its intention to respect negotiated rate contracts. Many of our rates are set pursuant to negotiated rate arrangements that consistent with the Final Rule will not be subject to adjustment due to changes in tax law. Also, many of our current transactions are provided at discounted rates that are below maximum tariff rates, many of which would not be impacted by a change in the maximum tariff rate. Further, on many of our pipelines we are operating under rate settlements that limit changes to their terms during the life of the settlement.

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 (Revised Policy Statement) 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. Requests for rehearing were filed in the Revised Policy Statement docket as well as the SFPP dockets in which the Revised Policy Statement was applied. The requests for rehearing in the SFPP dockets remain pending at the FERC. On July 18, 2018, the FERC issued an Order on Rehearing in the Revised Policy Statement docket in which it denied the rehearing petitions and clarified that the issue of entitlement to an income tax allowance will continue to be resolved in individual proceedings, including proceedings involving income tax pass-through entities. The FERC also clarified that when an income tax allowance is eliminated from cost of service, previously ADIT balances associated with such income tax allowance may also be eliminated. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $30 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. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. 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. The rehearing and judicial review process is scheduled to begin in August of 2018. 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. On May 3, 2018, the FERC issued Opinion 528-B upholding its decisions in Opinion 528-A, effectively denying the motion of the customer group, and requiring EPNG to implement the rates required by its rulings and provide refunds within 60 days. On July 2, 2018, EPNG reported to the FERC the refund calculations, and that the refunds had been provided as ordered. Also on July 2, 2018, EPNG initiated appellate review of Opinions 528, 528-A and 528-B.

TMEP Litigation

There are numerous legal challenges pending before the Federal Court of Appeal that have been filed by various governmental and non-governmental organizations, First Nations or other parties seeking 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 were commenced at the Supreme Court of BC by the Squamish Nation and the City of Vancouver. The petitions alleged a duty and failure to consult or accommodate First Nations, and generally, among other claims, that the Province should not have approved the TMEP, and sought to quash the Environmental Assessment Certificate (EAC) 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. On May 24, 2018, the Court dismissed both proceedings. On June 22, 2018, the City of Vancouver filed its notice to appeal the decision to the BC Court of Appeal, and on June 25, 2018, the Squamish Nation also filed an appeal to the BC Court of Appeal. Any decision of the BC Court of Appeal may be appealed to the Supreme Court of Canada. 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.

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 a 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. On May 9, 2018, Burnaby applied for leave to 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.

On April 25, 2018, the BC Lieutenant Governor in Council referred a question to the BC Court of Appeal regarding the constitutionality of draft legislation seeking to impose a requirement for a hazardous substance permit on all persons having possession, charge or control of a certain volume of "heavy oil" in the course of operating an industry, trade or business. We believe the draft legislation, if enacted, would apply to TMEP. On June 18, 2018, the Court granted 20 persons participatory status in the reference matter, including Trans Mountain. The Court has scheduled a hearing on the referenced matter to begin on March 18, 2019. As a result of the filing or resolution of this or any related reference matter, among other potential impacts, there may be significant changes to the TMEP plans, further obligations or restrictions may be imposed or the TMEP may be stopped altogether.

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 were 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 were 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 sought 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. On June 29, 2018, the arbitration panel delivered its Award, and the panel's ruling calls for the termination of the agreement and Eni USA's payment of compensation to GLNG. The Award resulted in our recording a net loss in our equity investment in GLNG due to a non-cash impairment of our investment in GLNG partially offset by our share of earnings recognized by GLNG.

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 alleged 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 claimed 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 asserted 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. On June 8, 2018, the Delaware Supreme Court affirmed 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, and that dismissal is final.

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 June 30, 2018 and December 31, 2017, our total reserve for legal matters was $411 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 were 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. During the first quarter of 2018, KMEP and SFPP settled 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 Occidental Chemical Company (OCC), a member of the PRP group requiring OCC to spend an estimated $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. On June 30, 2018 and July 13, 2018, respectively, OCC filed two separate lawsuits in the U.S. District Court for the District of New Jersey seeking cost recovery and contribution under CERCLA from more than 120 defendants, including EPEC Polymers. OCC alleges that each defendant is responsible to reimburse OCC for a proportionate share of the $165 million OCC is required to spend pursuant to its AOC. We intend to vigorously defend the lawsuit.

In addition, the EPA and numerous PRPs, including EPEC Polymers and EPEC Oil Trust, are engaged in an allocation process for the implementation of the remedy for the lower eight miles of the Passaic River Study area. 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). The case is one of numerous similar cases pending in Louisiana. As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other 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 and set trials to begin in 2019. The case involving TGP was set for trial in 2020. During May 2018, the defendants removed numerous cases which allege violations under the Coastal Zone Management Act to federal court in Louisiana; the case involving TGP was removed to the U.S. District Court for the Eastern District of Louisiana. Thereafter, the defendants moved the U.S. Judicial Panel on Multidistrict Litigation to transfer all such cases, including the case involving TGP, to the U.S. District Court for the Eastern District of Louisiana for coordinated proceedings. All of the cases, including the case involving TGP, have been stayed pending resolution of the removal and transfer issues. 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 alleged 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 sought 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. On May 22, 2018, the LDNR and LAG likewise 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. On May 4, 2018, the Court entered a judgment dismissing the tort and negligence claims against all of the defendants, and dismissing certain of the contract claims against TGP. In ruling in favor of plaintiffs on the remaining contract claims, the Court ordered the Defendants to pay $1,104 in money damages, and issued a permanent injunction ordering the Defendants to restore a total of 9.6 acres of land and maintain certain canals at widths designated by the right of way agreements in effect. The Court stayed the judgment and the injunction pending appeal. We are appealing the judgment and the injunction to the U.S. Court of Appeals for the Fifth Circuit.

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 both June 30, 2018 and December 31, 2017, we have accrued a total reserve for environmental liabilities in the amount of $279 million. In addition, as of both June 30, 2018 and December 31, 2017, we have recorded a receivable of $13 million for expected cost recoveries that have been deemed probable.

12. Recent Accounting Pronouncements

Topic 842

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.

On January 25, 2018, the FASB issued ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842." This ASU permits an entity to elect a transition practical expedient that 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.

We are in the process of assessing contracts to identify leases based on the modified definition of a lease, selecting a lease accounting system, evaluating internal control changes to support management in the accounting for and disclosure of leasing activities, and assessing currently available and proposed transition practical expedients. Topic 842 will be effective for us as of January 1, 2019.

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.

13. 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.

Excluding fair value adjustments, as of June 30, 2018, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $15,276 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 June 30, 2018 condensed consolidating balance sheet is approximately $161 million of capital lease obligations that are not subject to the cross guarantee agreement.

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 June 30, 2018
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ —	$ —	$ 3,047	$ 399	$ (18)	$ 3,428
Operating Costs, Expenses and Other						
Costs of sales	—	—	1,022	52	(6)	1,068
Depreciation, depletion and amortization	4	—	486	81	—	571
Other operating expense	6	—	1,377	146	(12)	1,517
Total Operating Costs, Expenses and Other	10	—	2,885	279	(18)	3,156
Operating (Loss) Income	(10)	—	162	120	—	272
Other Income (Expense)						
(Losses) earnings from consolidated subsidiaries	(2)	(55)	96	4	(43)	—
Earnings from equity investments	—	—	58	—	—	58
Interest, net	(193)	(2)	(273)	(48)	—	(516)
Amortization of excess cost of equity investments and other, net	7	—	(5)	8	—	10
(Loss) Income Before Income Taxes	(198)	(57)	38	84	(43)	(176)
Income Tax Benefit (Expense)	57	(2)	(19)	10	—	46
Net (Loss) Income	(141)	(59)	19	94	(43)	(130)
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(11)	(11)
Net (Loss) Income Attributable to Controlling Interests	(141)	(59)	19	94	(54)	(141)
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net (Loss) Income Available to Common Stockholders	$ (180)	$ (59)	$ 19	$ 94	$ (54)	$ (180)
Net (Loss) Income	$ (141)	$ (59)	$ 19	$ 94	$ (43)	$ (130)
Total other comprehensive loss	(23)	(42)	(44)	(58)	128	(39)
Comprehensive (loss) income	(164)	(101)	(25)	36	85	(169)
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	5	5
Comprehensive (loss) income attributable to controlling interests	$ (164)	$ (101)	$ (25)	$ 36	$ 90	$ (164)

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Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended June 30, 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	$ —	$ 3,002	$ 402	$ (45)	$ 3,368
Operating Costs, Expenses and Other						
Costs of sales	—	—	1,021	83	(34)	1,070
Depreciation, depletion and amortization	4	—	488	85	—	577
Other operating expenses	10	—	711	93	(11)	803
Total Operating Costs, Expenses and Other	14	—	2,220	261	(45)	2,450
Operating (Loss) Income	(5)	—	782	141	—	918
Other Income (Expense)						
Earnings from consolidated subsidiaries	747	734	110	17	(1,608)	—
Earnings from equity investments	—	—	135	—	—	135
Interest, net	(177)	4	(273)	(17)	—	(463)
Amortization of excess cost of equity investments and other, net	—	—	6	3	—	9
Income Before Income Taxes	565	738	760	144	(1,608)	599
Income Tax Expense	(189)	(1)	(18)	(8)	—	(216)
Net Income	376	737	742	136	(1,608)	383
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(7)	(7)
Net Income Attributable to Controlling Interests	376	737	742	136	(1,615)	376
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net Income Available to Common Stockholders	337	737	742	136	(1,615)	337
Net Income	$ 376	$ 737	$ 742	$ 136	$ (1,608)	$ 383
Total other comprehensive income	59	168	194	52	(395)	78
Comprehensive income	435	905	936	188	(2,003)	461
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(26)	(26)
Comprehensive income attributable to controlling interests	$ 435	$ 905	$ 936	$ 188	$ (2,029)	$ 435

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Condensed Consolidating Statements of Income and Comprehensive Income
for the Six Months Ended June 30, 2018
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ —	$ —	$ 6,127	$ 785	$ (66)	$ 6,846
Operating Costs, Expenses and Other						
Costs of sales	—	—	2,001	129	(43)	2,087
Depreciation, depletion and amortization	9	—	970	162	—	1,141
Other operating (income) expense	(19)	1	2,120	318	(23)	2,397
Total Operating Costs, Expenses and Other	(10)	1	5,091	609	(66)	5,625
Operating Income (Loss)	10	(1)	1,036	176	—	1,221
Other Income (Expense)						
Earnings from consolidated subsidiaries	804	690	147	20	(1,661)	—
Earnings from equity investments	—	—	278	—	—	278
Interest, net	(377)	(6)	(546)	(54)	—	(983)
Amortization of excess cost of equity investments and other, net	13	—	(15)	16	—	14
Income Before Income Taxes	450	683	900	158	(1,661)	530
Income Tax Expense	(67)	(4)	(45)	(2)	—	(118)
Net Income	383	679	855	156	(1,661)	412
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(29)	(29)
Net Income Attributable to Controlling Interests	383	679	855	156	(1,690)	383
Preferred Stock Dividends	(78)	—	—	—	—	(78)
Net Income Available to Common Stockholders	$ 305	$ 679	$ 855	$ 156	$ (1,690)	$ 305
Net Income	$ 383	$ 679	$ 855	$ 156	$ (1,661)	$ 412
Total other comprehensive loss	(40)	(98)	(101)	(136)	295	(80)
Comprehensive income	343	581	754	20	(1,366)	332
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	11	11
Comprehensive income attributable to controlling interests	$ 343	$ 581	$ 754	$ 20	$ (1,355)	$ 343

Condensed Consolidating Statements of Income and Comprehensive Income
for the Six Months Ended June 30, 2017
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 18	$ —	$ 6,060	$ 777	$ (63)	$ 6,792
Operating Costs, Expenses and Other						
Costs of sales	—	—	2,018	154	(41)	2,131
Depreciation, depletion and amortization	8	—	964	163	—	1,135
Other operating expenses	25	—	1,402	226	(22)	1,631
Total Operating Costs, Expenses and Other	33	—	4,384	543	(63)	4,897
Operating (Loss) Income	(15)	—	1,676	234	—	1,895
Other Income (Expense)						
Earnings from consolidated subsidiaries	1,593	1,561	212	35	(3,401)	—
Earnings from equity investments	—	—	310	—	—	310
Interest, net	(354)	10	(555)	(29)	—	(928)
Amortization of excess cost of equity investments and other, net	—	—	6	7	—	13
Income Before Income Taxes	1,224	1,571	1,649	247	(3,401)	1,290
Income Tax Expense	(408)	(3)	(35)	(16)	—	(462)
Net Income	816	1,568	1,614	231	(3,401)	828
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(12)	(12)
Net Income Attributable to Controlling Interests	816	1,568	1,614	231	(3,413)	816
Preferred Stock Dividends	(78)	—	—	—	—	(78)
Net Income Available to Common Stockholders	738	1,568	1,614	231	(3,413)	738
Net Income	$ 816	$ 1,568	$ 1,614	$ 231	$ (3,401)	$ 828
Total other comprehensive income	127	274	293	73	(621)	146
Comprehensive income	943	1,842	1,907	304	(4,022)	974
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(31)	(31)
Comprehensive income attributable to controlling interests	$ 943	$ 1,842	$ 1,907	$ 304	$ (4,053)	$ 943

Condensed Consolidating Balance Sheets as of June 30, 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	$ 9	$ —	$ —	$ 266	$ (4)	$ 271
Other current assets - affiliates	4,305	5,038	22,139	982	(32,464)	—
All other current assets	254	51	1,795	273	(10)	2,363
Property, plant and equipment, net	239	—	30,555	9,111	—	39,905
Investments	664	—	6,492	137	—	7,293
Investments in subsidiaries	39,870	37,662	5,513	4,271	(87,316)	—
Goodwill	13,789	22	5,166	3,176	—	22,153
Notes receivable from affiliates	963	20,352	626	904	(22,845)	—
Deferred income taxes	3,559	—	—	—	(1,606)	1,953
Other non-current assets	251	89	3,935	102	—	4,377
Total assets	$ 63,903	$ 63,214	$ 76,221	$ 19,222	$ (144,245)	$ 78,315
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 490	$ 1,300	$ 30	$ 312	$ —	$ 2,132
Other current liabilities - affiliates	12,783	14,189	4,622	870	(32,464)	—
All other current liabilities	410	334	1,983	534	(14)	3,247
Long-term debt	14,945	16,737	3,035	649	—	35,366
Notes payable to affiliates	1,491	448	20,551	355	(22,845)	—
Deferred income taxes	—	—	490	1,116	(1,606)	—
All other long-term liabilities and deferred credits	749	188	1,028	530	—	2,495
Total liabilities	30,868	33,196	31,739	4,366	(56,929)	43,240
Redeemable noncontrolling interest	—	—	581	—	—	581
Stockholders' equity						
Total KMI equity	33,035	30,018	43,901	14,856	(88,775)	33,035
Noncontrolling interests	—	—	—	—	1,459	1,459
Total stockholders' equity	33,035	30,018	43,901	14,856	(87,316)	34,494
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 63,903	$ 63,214	$ 76,221	$ 19,222	$ (144,245)	$ 78,315

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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 Six Months Ended June 30, 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	$(2,142)	$2,048	$5,644	$519	$(3,601)	$2,468
Cash flows from investing activities						
Acquisitions of assets and investments	—	—	(20)	—	—	(20)
Capital expenditures	(16)	—	(940)	(517)	—	(1,473)
Proceeds from sales of equity investments	—	—	33	—	—	33
Sales of property, plant and equipment, and other net assets, net of removal costs	3	—	(6)	9	—	6
Contributions to investments	—	—	(106)	(5)	—	(111)
Distributions from equity investments in excess of cumulative earnings	1,910	—	149	—	(1,910)	149
Funding (to) from affiliates	(4,016)	5	(3,737)	(489)	8,237	—
Loans to related party	—	—	(16)	—	—	(16)
Net cash (used in) provided by investing activities	(2,119)	5	(4,643)	(1,002)	6,327	(1,432)
Cash flows from financing activities						
Issuances of debt	8,297	—	—	268	—	8,565
Payments of debt	(6,737)	(975)	(779)	(84)	—	(8,575)
Debt issue costs	(24)	—	—	(7)	—	(31)
Cash dividends - common shares	(719)	—	—	—	—	(719)
Cash dividends - preferred shares	(78)	—	—	—	—	(78)
Repurchases of common shares	(250)	—	—	—	—	(250)
Funding from affiliates	3,779	1,517	2,499	442	(8,237)	—
Contributions from investment partner	—	—	97	—	—	97
Contributions from parents	—	—	17	—	(17)	—
Contributions from noncontrolling interests	—	—	—	—	17	17
Distributions to parents	—	(2,573)	(2,835)	(135)	5,543	—
Distributions to noncontrolling interests	—	—	—	—	(35)	(35)
Other, net	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	4,267	(2,031)	(1,001)	484	(2,729)	(1,010)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	(5)	—	(5)
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	6	22	—	(4)	(3)	21
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3	1	—	323	(1)	326
Cash, Cash Equivalents, and Restricted Deposits, end of period	$9	$23	$—	$319	$(4)	$347

Condensed Consolidating Statements of Cash Flows for the Six Months Ended June 30, 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	$ (1,460)	$ 2,076	$ 5,813	$ 509	$ (4,772)	$ 2,166
Cash flows from investing activities						
Acquisitions of assets and investments	—	—	(4)	—	—	(4)
Capital expenditures	(23)	—	(1,062)	(251)	—	(1,336)
Sales of property, plant and equipment, and other net assets, net of removal costs	5	—	45	21	—	71
Contributions to investments	(215)	—	(327)	(6)	—	(548)
Distributions from equity investments in excess of cumulative earnings	1,025	—	195	—	(1,006)	214
Funding (to) from affiliates	(2,806)	657	(4,013)	(482)	6,644	—
Loans (to) from related party	(8)	1	—	—	—	(7)
Net cash (used in) provided by investing activities	(2,022)	658	(5,166)	(718)	5,638	(1,610)
Cash flows from financing activities						
Issuances of debt	4,187	—	—	143	—	4,330
Payments of debt	(4,858)	(600)	(659)	(7)	—	(6,124)
Debt issue costs	(6)	—	—	(54)	—	(60)
Cash dividends - common shares	(560)	—	—	—	—	(560)
Cash dividends - preferred shares	(78)	—	—	—	—	(78)
Funding from (to) affiliates	4,356	406	2,444	(562)	(6,644)	—
Contribution from investment partner	—	—	415	—	—	415
Contributions from parents, including proceeds from KML IPO	—	—	(2)	1,253	(1,251)	—
Contributions from noncontrolling interests - net proceeds from KML IPO	7	—	—	—	1,240	1,247
Contributions from noncontrolling interests - other	—	—	—	—	11	11
Distributions to parents	—	(2,569)	(2,854)	(365)	5,788	—
Distributions to noncontrolling interests	—	—	—	—	(15)	(15)
Other, net	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	3,047	(2,763)	(656)	408	(871)	(835)
Effect of exchange rate changes on cash, cash equivalents and restricted deposits	—	—	—	10	—	10
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	(435)	(29)	(9)	209	(5)	(269)

Cash, Cash Equivalents, and Restricted Deposits, beginning of period	471	36	9	272	(1)	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 36	$ 7	$ —	$ 481	$ (6)	$ 518

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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 8 "Revenue Recognition" to our consolidated financial statements.

Pending Sale of Trans Mountain Pipeline System (TMPL) and Its Expansion Project

On April 8, 2018, KML announced that it was suspending all non-essential activities and related spending on the TMEP. On May 29, 2018, KML announced that the Government of Canada had agreed to purchase the TMPL, the TMEP, Puget Sound pipeline system, and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business and assets to be sold, for C$4.5 billion (the "Transaction"), subject to certain adjustments as provided in the share and unit purchase agreement (the "Purchase Agreement").

As part of the Purchase Agreement, the Government of Canada has agreed to fund the resumption of the TMEP planning and construction work by guaranteeing the TMEP's borrowings under a separately created temporary credit facility for such expenditures until the Transaction closes.

The Transaction is expected to close late in the third quarter or early in the fourth quarter of 2018, subject to KML's shareholder and applicable regulatory approvals. The assets to be sold will be classified as assets held for sale upon KML shareholder approval and the Transaction is expected to result in a gain. The use of proceeds from the sale of the TMPL and the TMEP is a KML board decision. We intend to use any proceeds we receive in respect of our interest in KML to pay down debt. Our share of the after-tax proceeds will be approximately $2 billion.

After the closing of the Transaction, KML will continue to manage a portfolio of strategic infrastructure assets across Western Canada, including (i) the crude terminal facilities, which constitute the largest merchant terminal storage position in the Edmonton market and the largest origination crude by rail loading facility in North America; (ii) the Vancouver Wharves Terminal, the largest mineral concentrate export/import facility on the west coast of North America; (iii) the Jet Fuel pipeline system; and (iv) the Canadian portion of the U.S. and Canadian Cochin pipeline system.

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 June 30, 2018	2017	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$313	$907	$(594)	(65)%
CO_2	157	221	(64)	(29)%
Terminals	274	304	(30)	(10)%
Products Pipelines	319	324	(5)	(2)%
Kinder Morgan Canada	46	43	3	7%
Total Segment EBDA(b)	1,109	1,799	(690)	(38)%
DD&A	(571)	(577)	6	1%
Amortization of excess cost of equity investments	(24)	(15)	(9)	(60)%
General and administrative and corporate charges(c)	(174)	(145)	(29)	(20)%
Interest, net(d)	(516)	(463)	(53)	(11)%
(Loss) income before income taxes	(176)	599	(775)	(129)%
Income tax benefit (expense)	46	(216)	262	121%
Net (loss) income	(130)	383	(513)	(134)%
Net income attributable to noncontrolling interests	(11)	(7)	(4)	(57)%
Net (loss) income attributable to Kinder Morgan, Inc.	(141)	376	(517)	(138)%
Preferred stock dividends	(39)	(39)	—	—%
Net (loss) income available to common stockholders	$(180)	$337	$(517)	(153)%

	Six Months Ended June 30, 2018	2017	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$1,449	$1,962	$(513)	(26)%
CO_2	356	439	(83)	(19)%
Terminals	569	611	(42)	(7)%
Products Pipelines	578	611	(33)	(5)%
Kinder Morgan Canada	92	86	6	7%
Total Segment EBDA(b)	3,044	3,709	(665)	(18)%
DD&A	(1,141)	(1,135)	(6)	(1)%
Amortization of excess cost of equity investments	(56)	(30)	(26)	(87)%
General and administrative and corporate charges(c)	(334)	(326)	(8)	(2)%
Interest, net(d)	(983)	(928)	(55)	(6)%
Income before income taxes	530	1,290	(760)	(59)%
Income tax expense	(118)	(462)	344	74%
Net income	412	828	(416)	(50)%
Net income attributable to noncontrolling interests	(29)	(12)	(17)	(142)%
Net income attributable to Kinder Morgan, Inc.	383	816	(433)	(53)%
Preferred Stock Dividends	(78)	(78)	—	—%
Net income Available to Common Stockholders	$305	$738	$(433)	(59)%

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(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, loss on impairments and divestitures, net, loss on impairment of equity investment and 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) Three and six month 2018 amounts include net decreases in earnings of $785 million and $801 million, respectively, and three and six month 2017 amounts include net increases in earnings of $42 million and $79 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) Three and six month 2018 amounts include net increases in expense of $14 million and $10 million, respectively, and three and six month 2017 amounts include a net decrease in expense of $4 million and a net increase in expense of $3 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) Three and six month 2018 amounts include net increases in expense of $39 million and $34 million, respectively, and three and six month 2017 amounts include net decreases in expense of $5 million and $17 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) through (d) to the table above accounted for a $889 million decrease in income before income taxes for the second quarter of 2018, as compared to the same prior year period (representing the difference between a decrease of $838 million and an increase of $51 million in income before income taxes for the second quarter of 2018 and 2017, respectively) and a $938 million decrease in income before income taxes for the six months ended June 30, 2018, as compared to the same prior year period (representing the difference between a decrease of $845 million and an increase of $93 million in income before income taxes for the six months ended June 30, 2018 and 2017, respectively).

After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining increases in income before income taxes from the prior year quarter and year-to-date were $114 million (21%) and $178 million (15%), respectively. The quarter-to-date increase from 2017 is primarily attributable to increased performance from our Natural Gas Pipelines, Products Pipelines and Terminals business segments partially offset by increased general and administrative expense and increased interest expense. The year-to-date increase from 2017 is primarily attributable to increased performance from all of our business segments 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 (loss) 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 (Loss) Income Available to Common Stockholders to DCF

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except per share amounts)			
Net (Loss) Income Available to Common Stockholders	$(180)	$337	$305	$738
Add/(Subtract):				
Certain items before book tax(a)	838	(51)	889	(93)
Book tax certain items(b)	(191)	17	(194)	29
Impact of 2017 Tax Reform(c)	—	—	(44)	—
Total certain items	647	(34)	651	(64)
Noncontrolling interest certain items(d)	(8)	1	(8)	1
Net income available to common stockholders before certain items	459	304	948	675
Add/(Subtract):				
DD&A expense(e)	684	686	1,374	1,357
Total book taxes(f)	159	223	343	484
Cash taxes(g)	(33)	(48)	(46)	(45)
Other items(h)	11	13	22	26
Sustaining capital expenditures(i)	(163)	(156)	(277)	(260)
DCF	$1,117	$1,022	$2,364	$2,237
Weighted average common shares outstanding for dividends(j)	2,214	2,239	2,216	2,239
DCF per common share	$0.50	$0.46	$1.07	$1.00
Declared dividend per common share	$0.20	$0.125	$0.40	$0.25

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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) Represents noncontrolling interests share of certain items.

(e) Includes DD&A and amortization of excess cost of equity investments. Three and six month 2018 amounts also include $89 million and $177 million, respectively, and three and six month 2017 amounts also include $94 million and $192 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.

(f) Excludes book tax certain items. Three and six month 2018 amounts also include $14 million and $31 million, respectively, and three and six month 2017 amounts also include $24 million and $51 million, respectively, of our share of taxable equity investees' book taxes, net of the noncontrolling interests' portion of KML book taxes.

(g) Three and six month 2018 amounts also include $(28) million and $(38) million, respectively, and three and six month 2017 amounts also include $(45) million for both periods, of our share of taxable equity investees' cash taxes.

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

(i) Three and six month 2018 amounts include $(24) million and $(40) million, respectively, and three and six month 2017 amounts include $(27) million and $(45) million, respectively, of our share of (i) certain equity investees'; (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures.

(j) 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except operating statistics)			
Revenues(a)	$2,166	$2,095	$4,332	$4,266
Operating expenses(b)	(1,297)	(1,312)	(2,529)	(2,584)
Loss on impairments and divestitures, net(b)	(599)	—	(599)	—
Other income	1	—	1	—
Earnings from equity investments(b)	26	109	211	255
Other, net	16	15	33	25
Segment EBDA(b)	313	907	1,449	1,962
Certain items(b)	688	(2)	634	(38)
Segment EBDA before certain items	$1,001	$905	$2,083	$1,924
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$75	4 %	$79	2 %
Segment EBDA before certain items	$96	11 %	$159	8 %
Natural gas transport volumes (BBtu/d)(c)	31,704	28,187	31,913	28,753
Natural gas sales volumes (BBtu/d)(c)	2,445	2,247	2,468	2,404
Natural gas gathering volumes (BBtu/d)(c)	2,871	2,673	2,801	2,693
Crude/condensate gathering volumes (MBbl/d)(c)	311	261	296	267

Certain items affecting Segment EBDA

(a) Three and six month 2018 amounts include decreases in revenue of $11 million and $5 million, respectively, and three and six month 2017 amounts include increases of $7 million and $22 million, respectively, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. Three and six month 2018 amounts also include increases in revenue for both periods of $9 million related to a transportation contract refund and $5 million related to the early termination of a long-term natural gas transportation contract.

(b) In addition to the revenue certain items described in footnote (a) above: three and six month 2018 amounts also include (i) a $600 million non-cash loss on impairment of certain gathering and processing assets in Oklahoma for both periods; (ii) a net loss of $89 million in our equity investment in Gulf LNG Holdings Group, LLC (Gulf LNG) for both periods, due to a ruling by an arbitration panel affecting a customer contract, which resulted in a non-cash impairment of our investment partially offset by our share of earnings recognized by Gulf LNG on the respective customer contract; and (iii) decreases in earnings of $2 million and $4 million, respectively, related to other certain items. Six month 2018 amount also includes an increase in earnings of $44 million for our share of certain equity investees' 2017 Tax Reform provisional adjustments and an increase in earnings of $6 million related to the release of certain sales and use tax reserves. Three and six month 2017 amounts also include decreases in earnings of $5 million and $6 million, respectively, from other certain items. Also, six month 2017 amount includes 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.
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 and six month periods ended June 30, 2018 and 2017:

Three Months Ended June 30, 2018 versus Three Months Ended June 30, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Hiland Midstream	$21	51 %	$ (22)	(12)%
EPNG	20	19 %	20	13 %
Texas Intrastate Natural Gas Pipeline Operations	8	10 %	(29)	(4)%
TGP	7	2 %	11	3 %
KinderHawk	7	41 %	8	38 %
NGPL	6	200%	9	n/a
CIG	6	12 %	5	7 %
Citrus(a)	4	13 %	—	— %
SNG(a)	3	12 %	1	14 %
All others (including eliminations)	14	5 %	72	15 %
Total Natural Gas Pipelines	$96	11 %	$ 75	4 %

Six Months Ended June 30, 2018 versus Six Months Ended June 30, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Hiland Midstream	$31	36 %	$ (37)	(11)%
EPNG	26	11 %	29	9 %
Texas Intrastate Natural Gas Pipeline Operations	42	22 %	(18)	(1)%
TGP	(8)	(1)%	21	3 %
KinderHawk	11	31 %	12	29 %
NGPL	13	87 %	18	n/a
CIG	10	9 %	8	5 %
Citrus(a)	10	20 %	—	— %
SNG(a)	9	15 %	1	7 %
All others (including eliminations)	15	3 %	45	5 %
Total Natural Gas Pipelines	$159	8 %	$ 79	2 %

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

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 and six month periods ended June 30, 2018 and 2017:

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increases of $21 million (51%) and $31 million (36%), respectively, from Hiland Midstream primarily due to higher natural gas margins resulting from increased gathered volumes, higher NGL sales prices, and higher crude oil margins driven by higher crude oil transport and sales volumes. The decrease in revenues of $22 million and $37 million, respectively, are primarily due to the $71 million and $160 million, respectively, effect of the January 1, 2018 adoption of Topic 606 as discussed in Note 8 “Revenue Recognition” to our consolidated financial statements, partially offset by an increase of $49 million and $123 million, respectively, in sales revenues, primarily natural gas liquids and crude oil;

- increases of $20 million (19%) and $26 million (11%), respectively, from EPNG primarily due to higher transportation revenues driven by incremental Permian capacity sales;
- increases of $8 million (10%) and $42 million (22%), respectively, from our Texas intrastate natural gas pipeline operations. The quarter-to-date increase was primarily due to new customer transportation service revenues, higher volumes with existing customers and higher sales margins primarily due to incremental volumes sold to certain customers partially offset by lower storage margins. In addition to the above mentioned factors, the year-to-date increase

was favorably impacted by higher weather-related volumes. The decrease in revenues of $29 million and $18 million, respectively, resulted primarily from a decrease in natural gas sales revenue due to lower pricing (largely offset in Segment EBDA by a corresponding decrease in costs of sales) and lower processing revenue;

- increase of $7 million (2%) and decrease of $8 million (1%), respectively, from TGP. The quarter-to-date increase was primarily due to higher firm transportation revenues from expansion projects placed in service in latter part of 2017 and increased weather-related demand early in the quarter partially offset by lower capacity sales and higher Ad Valorem tax expense. The year-to-date decrease was primarily due to lower capacity sales and higher operations and maintenance expense and Ad Valorem tax expense partially offset by higher firm transportation revenues from 2017 expansion projects and higher weather related volume demand. The year-to-date revenues were also impacted by an increase in operational gas sales which was offset by an increase in associated gas cost for a net minimal impact on earnings;
- increases of $7 million (41%) and $11 million (31%), respectively, from KinderHawk primarily due to higher gathering revenues driven by an increase in volumes as a result of incremental production from the Haynesville;
- increases of $6 million (200%) and $13 million (87%), respectively, from NGPL due to lower interest expense and greater transport revenue resulting from increased weather-related demand in the first quarter and early in the second quarter of 2018 and power demand partially offset by cushion gas write-off;
- increases of $6 million (12%) and $10 million (9%), respectively, from CIG primarily due to higher firm transportation revenues driven by growth in the Denver Julesburg basin along with increased capacity sales, expansions and usage revenues due to improved midcontinent pricing and lower operating costs largely due to decreased pipeline integrity costs;
- increases of $4 million (13%) and $10 million (20%), respectively, from Citrus primarily due to lower income tax expense due to the 2017 Tax Reform. The quarter-to-date increase was partially offset by lower transportation revenues; and
- increases of $3 million (12%) and $9 million (15%), respectively, from SNG. The quarter-to-date increase is primarily due to lower operations and maintenance expense due to timing of pipeline integrity projects and higher usage revenues due to additional firm transportation volumes. The year-to-date increase is 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.

CO2

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions, except operating statistics)			
Revenues(a)	$250	$307	$554	$610
Operating expenses(b)	(101)	(95)	(216)	(192)
Gain on impairments and divestitures, net(b)	—	—	—	1
Earnings from equity investments	8	9	18	20
Segment EBDA(b)	157	221	356	439
Certain items(b)	64	(1)	102	3
Segment EBDA before certain items	$221	$220	$458	$442

Change from prior period	Increase/(Decrease)			
Revenues before certain items	$29	9 %	$63	10 %
Segment EBDA before certain items	$1	— %	$16	4 %

Southwest Colorado CO_2 production (gross)(Bcf/d)(c)	1.2	1.3	1.2	1.3
Southwest Colorado CO_2 production (net)(Bcf/d)(c)	0.5	0.6	0.6	0.7
SACROC oil production (gross)(MBbl/d)(d)	29.2	27.4	29.4	27.9
SACROC oil production (net)(MBbl/d)(e)	24.3	22.8	24.5	23.2
Yates oil production (gross)(MBbl/d)(d)	17.1	17.4	17.0	17.6
Yates oil production (net)(MBbl/d)(e)	7.4	7.7	7.6	7.8
Katz, Goldsmith and Tall Cotton oil production (gross)(MBbl/d)(d)	8.1	8.0	8.4	7.6
Katz, Goldsmith and Tall Cotton oil production (net)(MBbl/d)(e)	6.9	6.7	7.1	6.5
NGL sales volumes (net)(MBbl/d)(e)	10.1	9.9	10.1	10.0
Realized weighted-average oil price per Bbl(f)	$58.08	$57.80	$58.90	$57.97
Realized weighted-average NGL price per Bbl(g)	$32.88	$22.47	$31.64	$23.49

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Certain items affecting Segment EBDA

(a) Three and six month 2018 amounts include unrealized losses of $85 million and $123 million, respectively, and the three and six month 2017 amounts include unrealized losses of $8 million and $13 million, respectively, related to derivative contracts used to hedge forecasted commodity sales. Three and six months 2017 amounts also include an increase in revenues of $9 million related to the settlement of a CO_2 customer sales contract.

(b) In addition to the revenue certain items described in footnote (a) above: three and six month 2018 amounts also include increases in earnings for both periods of $21 million as a result of a severance tax refund and six month 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 and six month periods ended June 30, 2018 and 2017.

Three Months Ended June 30, 2018 versus Three Months Ended June 30, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)
	(In millions, except percentages)		
Source and Transportation Activities	$ (10)	(12)%	$ 6