KINDER MORGAN, INC.
Form 10-Q
October 21, 2016

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 September 30, 2016

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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 October 20, 2016, the registrant had 2,232,364,274 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

CIG	= Colorado Interstate Gas Company, L.L.C.	KMLP	= Kinder Morgan Louisiana Pipeline LLC
Copano	= Copano Energy, L.L.C.	KMP	= Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
CPG	= Cheyenne Plains Gas Pipeline Company, L.L.C.		
Elba Express	= Elba Express Company, L.L.C.	KMR	= Kinder Morgan Management, LLC
EPB	= El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	MEP	= Midcontinent Express Pipeline LLC
		SFPP	= SFPP, L.P.
EPNG	= El Paso Natural Gas Company, L.L.C.	SLNG	= Southern LNG Company, L.L.C.
Hiland	= Hiland Partners, LP	SNG	= Southern Natural Gas Company, L.L.C.
KMEP	= Kinder Morgan Energy Partners, L.P.	TGP	= Tennessee Gas Pipeline Company, L.L.C.
KMGP	= Kinder Morgan G.P., Inc.		
KMI	= Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries		

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

Common Industry and Other Terms

/d	= per day	EPA	= United States Environmental Protection Agency
BBtu	= billion British Thermal Units	FASB	= Financial Accounting Standards Board
Bcf	= billion cubic feet	FERC	= Federal Energy Regulatory Commission
CERCLA	= Comprehensive Environmental Response, Compensation and Liability Act	GAAP	= United States Generally Accepted Accounting Principles
CO_2	= carbon dioxide or our CO_2 business segment	LLC	= limited liability company
DCF	= distributable cash flow	MBbl	= thousand barrels
DD&A	= depreciation, depletion and amortization	MMBbl	= million barrels
EBDA	= earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	NGL	= natural gas liquids
		OTC	= over-the-counter

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

Information Regarding Forward-Looking Statements

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

See “Information Regarding Forward-Looking Statements” and Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015 (2015 Form 10-K) and Item 1A “Risk Factors” included elsewhere in this report 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues				
Natural gas sales	$719	$744	$1,740	$2,206
Services	2,006	2,015	6,154	5,948
Product sales and other	605	948	1,775	2,613
Total Revenues	3,330	3,707	9,669	10,767
Operating Costs, Expenses and Other				
Costs of sales	971	1,106	2,454	3,281
Operations and maintenance	576	612	1,744	1,707
Depreciation, depletion and amortization	549	617	1,652	1,725
General and administrative	171	160	550	540
Taxes, other than income taxes	106	108	324	339
Loss on impairments and divestitures, net	76	385	307	489
Other income, net	(1)	(2)	—	(5)
Total Operating Costs, Expenses and Other	2,448	2,986	7,031	8,076
Operating Income	882	721	2,638	2,691
Other Income (Expense)				
Earnings from equity investments	137	114	343	330
Loss on impairments and divestitures of equity investments, net	(350)	—	(344)	(26)
Amortization of excess cost of equity investments	(15)	(13)	(45)	(39)
Interest, net	(472)	(540)	(1,384)	(1,524)
Other, net	12	9	42	33
Total Other Expense	(688)	(430)	(1,388)	(1,226)
Income Before Income Taxes	194	291	1,250	1,465
Income Tax Expense	(377)	(108)	(744)	(521)
Net (Loss) Income	(183)	183	506	944
Net (Income) Loss Attributable to Noncontrolling Interests	(5)	3	(7)	4
Net (Loss) Income Attributable to Kinder Morgan, Inc.	(188)	186	499	948
Preferred Stock Dividends	(39)	—	(117)	—

Net (Loss) Income Available to Common Stockholders	$(227)	$186	$382	$948
Class P Shares				
Basic (Loss) Earnings Per Common Share	$(0.10)	$0.08	$0.17	$0.43
Basic Weighted Average Common Shares Outstanding	2,230	2,203	2,229	2,173
Diluted (Loss) Earnings Per Common Share	$(0.10)	$0.08	$0.17	$0.43
Diluted Weighted Average Common Shares Outstanding	2,230	2,203	2,229	2,181
Dividends Per Common Share Declared for the Period	$0.125	$0.510	$0.375	$1.480

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net (loss) income	$(183)	$183	$506	$944
Other comprehensive income (loss), net of tax				
Change in fair value of hedge derivatives (net of tax (expense) benefit of $(29), $(60), $11 and $(25), respectively)	50	104	(19)	44
Reclassification of change in fair value of derivatives to net income (net of tax benefit of $23, $37, $92 and $111, respectively)	(39)	(63)	(158)	(192)
Foreign currency translation adjustments (net of tax benefit (expense) of $11, $45, $(38) and $98, respectively)	(20)	(79)	65	(170)
Benefit plan adjustments (net of tax expense of $(3), $-, $(9) and $(4), respectively)	6	1	16	7
Total other comprehensive loss	(3)	(37)	(96)	(311)
Comprehensive (loss) income	(186)	146	410	633
Comprehensive (income) loss attributable to noncontrolling interests	(5)	3	(7)	4
Comprehensive (loss) income attributable to KMI	$(191)	$149	$403	$637

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

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

	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$ 357	$ 229
Restricted deposits	888	60
Accounts receivable, net	1,282	1,315
Fair value of derivative contracts	281	507
Inventories	325	407
Other current assets	230	306
Total current assets	3,363	2,824
Property, plant and equipment, net	38,780	40,547
Investments	7,358	6,040
Goodwill	22,163	23,790
Other intangibles, net	3,384	3,551
Deferred income taxes	4,595	5,323
Deferred charges and other assets	1,961	2,029
Total Assets	$ 81,604	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of debt	$ 2,944	$ 821
Accounts payable	1,192	1,324
Accrued interest	505	695
Accrued contingencies	413	298
Accrued taxes	278	165
Other current liabilities	712	762
Total current liabilities	6,044	4,065
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	36,708	40,632
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,710	1,674
Total long-term debt	38,518	42,406
Other long-term liabilities and deferred credits	2,074	2,230
Total long-term liabilities and deferred credits	40,592	44,636
Total Liabilities	46,636	48,701
Commitments and contingencies (Notes 3 and 9)		
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,230,085,392 and 2,229,223,864 shares, respectively, issued and outstanding	22	22
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, 1,600,000 shares issued and outstanding	—	—
Additional paid-in capital	41,701	41,661

Retained deficit	(6,560)	(6,103)
Accumulated other comprehensive loss	(557)	(461)
Total Kinder Morgan, Inc.'s stockholders' equity	34,606	35,119
Noncontrolling interests	362	284
Total Stockholders' Equity	34,968	35,403
Total Liabilities and Stockholders' Equity	$ 81,604	$ 84,104

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)

	Nine Months Ended September 30,	
	2016	2015
Cash Flows From Operating Activities		
Net income	$506	$944
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	1,652	1,725
Deferred income taxes	767	524
Amortization of excess cost of equity investments	45	39
Loss on impairments and divestitures, net	307	489
Loss on impairments and divestitures of equity investments, net	344	26
Earnings from equity investments	(343)	(330)
Distributions from equity investment earnings	321	289
Noncash pension benefit credits	—	(78)
Changes in components of working capital, net of the effects of acquisitions and dispositions		
Accounts receivable, net	26	304
Income tax receivable	—	195
Inventories	68	2
Other current assets	(20)	82
Accounts payable	(46)	(264)
Accrued interest, net of interest rate swaps	(158)	(72)
Accrued contingencies and other current liabilities	140	6
Rate reparations, refunds and other litigation reserve adjustments	31	3
Other, net	(145)	(377)
Net Cash Provided by Operating Activities	3,495	3,507
Cash Flows From Investing Activities		
Acquisitions of assets and investments, net of cash acquired	(333)	(1,919)
Capital expenditures	(2,109)	(2,999)
Proceeds from sale of equity interests in subsidiaries, net	1,402	—
Sale of property, plant and equipment, investments, and other net assets, net of removal costs	250	45
Contributions to investments	(389)	(69)
Distributions from equity investments in excess of cumulative earnings	158	181
Other, net	(26)	39
Net Cash Used in Investing Activities	(1,047)	(4,722)
Cash Flows From Financing Activities		
Issuances of debt	8,485	12,281
Payments of debt	(9,135)	(11,893)
Restricted cash held in escrow for debt repayment	(776)	—
Debt issue costs	(15)	(20)
Issuances of common shares	—	3,833
Cash dividends - common shares	(839)	(3,084)
Cash dividends - preferred shares	(115)	—
Repurchases of warrants	—	(12)

Contributions from noncontrolling interests	88	7
Distributions to noncontrolling interests	(17)	(25)
Other, net	—	(1)
Net Cash (Used in) Provided by Financing Activities	(2,324)	1,086
Effect of Exchange Rate Changes on Cash and Cash Equivalents	4	(7)
Net increase (decrease) in Cash and Cash Equivalents	128	(136)
Cash and Cash Equivalents, beginning of period	229	315
Cash and Cash Equivalents, end of period	$357	$179
Non-cash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$43	$1,680
Net assets contributed to equity investment	$37	$46
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$1,598	$1,596
Cash paid (refunded) during the period for income taxes, net	$4	$(183)

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, 2015	2,229	$ 22	2	$ —	$ 41,661	$ (6,103)	$ (461)	$ 35,119	$ 284	$ 35,403
Restricted shares	1				47			47		47
Net income						499		499	7	506
Distributions								—	(17)	(17)
Contributions								—	88	88
Preferred stock dividends						(117)		(117)		(117)
Common stock dividends						(839)		(839)		(839)
Other					(7)			(7)		(7)
Other comprehensive loss							(96)	(96)		(96)
Balance at September 30, 2016	2,230	$ 22	2	$ —	$ 41,701	$ (6,560)	$ (557)	$ 34,606	$ 362	$ 34,968

	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, 2014	2,125	$ 21	—	$ —	$ 36,178	$ (2,106)	$ (17)	$ 34,076	$ 350	$ 34,426
Issuances of common shares	101	1			3,832			3,833		3,833
Repurchase of warrants					(12)			(12)		(12)
EP Trust I Preferred security conversions	1				23			23		23
Warrants exercised					2			2		2
Restricted shares	1				40			40		40
Net income						948		948	(4)	944
Distributions								—	(25)	(25)
Contributions								—	7	7
Common stock dividends						(3,084)		(3,084)		(3,084)
Other					(1)			(1)		(1)
Other comprehensive loss							(311)	(311)		(311)
Balance at September 30, 2015	2,228	$ 22	—	$ —	$ 40,062	$ (4,242)	$ (328)	$ 35,514	$ 328	$ 35,842

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

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

1. General

Organization

We are the largest energy infrastructure company in America. We own an interest in or operate approximately 84,000 miles of pipelines and 180 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store petroleum products, ethanol and chemicals, and handle such products as coal, petroleum coke and steel. We are also the leading producer and transporter of CO_2, which is utilized for enhanced oil recovery projects in North America.

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 presentation 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 2015 Form 10-K.

Impairments and Divestitures

During the three and nine months ended September 30, 2016, we recorded non-cash pre-tax losses on impairments and divestitures netting to $76 million and $307 million, respectively. The three and nine months ended September 30, 2016 included (i) an $84 million loss on the sale of a 50% interest in our SNG natural gas pipeline system; (ii) losses of $1 million and $9 million, respectively, on a held-for-sale Transmix facility within our Products Pipelines business segment; and (iii) a $9 million net gain and a $3 million net loss, respectively, on other asset disposals. The nine months ended September 30, 2016 also included (i) $106 million of project write-offs on our Northeast Energy Direct (NED) Market project within our Natural Gas Pipelines business segment; (ii) a $21 million project write-off within our CO_2 business segment; (iii) a $20 million impairment related to certain terminals with significant coal operations within our Terminals business segment; and (iv) $64 million of write-offs associated with our Palmetto project within our Products Pipelines business segment. The project write-offs recorded in the nine months ended September 30, 2016 were driven by management's assessment of the probability of those projects moving forward based on insufficient progress in obtaining contractual commitments from customers in the New England market, in the case of the NED Market project, and an unfavorable action by the Georgia legislature regarding permitting for refined products pipelines affecting the Palmetto project.

During the three and nine months ended September 30, 2015, we recorded non-cash pre-tax losses on impairments and divestitures netting to $385 million and $489 million, respectively. These amounts include (i) $99 million for the nine months ended September 30, 2015 of impairments and project write-offs related to certain gas gathering and processing assets within our midstream operations of our Natural Gas Pipelines business segment; (ii) $388 million and $397 million for the three and nine months ended September 30, 2015, respectively, within our CO_2 business segment primarily related to our Goldsmith oil and gas field, primarily driven by a decrease in commodity prices; and (iii) $3 million and $7 million for the three and nine months ended September 30, 2015, respectively, of net gains on other asset disposals.

During the three and nine months ended September 30, 2016, we recorded $350 million and $344 million, respectively, of non-cash pre-tax net losses on impairments and divestitures of equity investments, primarily related to an impairment of our equity investment in MEP within our Natural Gas Pipelines business segment. Based on commercial discussions during the third quarter of 2016 with current and potential shippers on MEP regarding the outlook for long-term transportation contract rates, we concluded the fair value of our investment was other than temporarily impaired, thereby resulting in a write-down of our investment. During the nine months ended September 30, 2015, we recorded $26 million non-cash pre-tax losses on impairments of equity investments in certain gas gathering operations within our Natural Gas Pipelines business segment.

As conditions warrant, we routinely evaluate our assets for potential triggering events that could impact the fair value of certain assets or our ability to recover the carrying value of long-lived assets. Such assets include accounts receivable, equity investments, goodwill, other intangibles and property, plant and equipment, including oil and gas properties and in-process construction. Depending on the nature of the asset, these evaluations require the use of significant judgments including but not limited to judgments related to customer credit worthiness, future cash flow estimates, future volume and long-term contract rate expectations, current and future commodity prices, regulatory environment, management's decisions to dispose of certain assets and estimates of the fair values of our reporting units, as well as general economic conditions and the related demand for products handled or transported by our assets. For example, to the extent future commodity prices are significantly lower than current market expectations and thereby unfavorably affect our customers' investment decisions, we may identify additional triggering events that may require future evaluations of the recoverability of the carrying value of our long-lived assets, investments, and goodwill which could result in further impairment charges. Because certain of our assets, including our oil and gas producing properties, have been written down to fair value, any deterioration in fair value that exceeds the rate of depletion of the related asset would result in 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 not be recoverable. Certain of these impairments are based on Level 3 estimates of fair value using income approach valuation methodologies which include assumptions regarding commodity prices, future cash flows, terminal values and discount rates. We believe our methodologies are standard techniques and results would not vary materially using a reasonable range of assumptions.

In the fourth quarter 2015, we recorded a $1,150 million impairment of goodwill associated with our Natural Gas Pipeline - Non-Regulated reporting unit triggered by decreases in market valuations in our industry which were caused by the commodity price environment at that time. Our May 31, 2016 annual goodwill impairment test indicated our remaining goodwill is recoverable, and no event indicating a goodwill impairment has occurred subsequent to that date.

We expect that the carrying value of our Natural Gas Pipelines - Non-Regulated reporting unit will continue to approximate fair value so long as our estimate of future cash flows and the market valuation remain consistent with current levels. A prolonged period of lower commodity prices could result in further deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. Unfavorable changes to any one or combination of these factors, particularly for our Natural Gas Pipelines - Non-Regulated reporting unit, would result in a change to the reporting unit fair values which could lead to further impairment charges. Such potential impairment could have a significant effect on our results of operations.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P shares of common stock 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 stock or stock units issued to management employees and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following tables set forth the allocation of net income available to shareholders of Class P shares and participating securities and the reconciliation of Basic Weighted Average Common Shares Outstanding to Diluted Weighted Average Common Shares Outstanding (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Class P shares	$(228)	$182	$379	$938
Participating securities:				
Restricted stock awards(a)	1	4	3	10
Net (Loss) Income Available to Common Stockholders	$(227)	$186	$382	$948

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Basic Weighted Average Common Shares Outstanding	2,230	2,203	2,229	2,173
Effect of dilutive securities:				
Warrants	—	—	—	8
Diluted Weighted Average Common Shares Outstanding	2,230	2,203	2,229	2,181

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(a) As of September 30, 2016, there were approximately 9 million such restricted stock awards.

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Unvested restricted stock awards	9	8	8	7
Warrants to purchase our Class P shares(a)	293	296	293	290
Convertible trust preferred securities	8	8	8	8
Mandatory convertible preferred stock(b)	58	n/a	58	n/a

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n/a - not applicable

(a) Each warrant entitles the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise, at any time until May 25, 2017. The potential dilutive effect of the warrants does 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 dividends.

2. Acquisitions and Divestiture

Acquisition of Terminal Assets from and Joint Venture With BP Products North America Inc. (BP)

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $349 million, including a transaction deposit paid in 2015 and working capital adjustments paid in 2016. In conjunction with this transaction, we and BP formed a joint venture, with an equity ownership interest of 75% and 25%, respectively. Subsequent to the acquisition, we contributed 14 of the acquired terminals to the joint venture, which we operate, and the remaining terminal is solely owned by us. BP acquired its 25% interest in the joint venture for $84 million, which we reported as “Contributions from noncontrolling interests” within our accompanying consolidated statement of cash flows for the nine months ended September 30, 2016. Of the acquired assets, 10 terminals are included in our Terminals business segment and 5 terminals are included in our Products Pipelines business segment based on synergies with each segment’s respective existing operations.

Allocation of Purchase Price

The evaluation of the assigned fair values for the BP terminals acquisition is ongoing and subject to adjustment. As of September 30, 2016, our preliminary allocation of the purchase price for the BP terminals acquisition and the adjusted purchase price allocations for the Hiland acquisition and Royal Vopak terminals acquisition, both completed in February 2015, are detailed below (in millions).

	Acquisitions		
	BP Terminal Assets	Hiland	Royal Vopak Terminal Assets
Purchase Price Allocation:			
Current assets	$2	$79	$ 2
Property, plant and equipment	396	1,492	155
Goodwill	—	310	6
Deferred charges and other assets(a)	—	1,498	—
Total assets acquired	398	3,379	163
Current liabilities	—	(253)	(1)
Debt	—	(1,413)	—
Other liabilities	(49)	(4)	(4)
Cash consideration	$349	$1,709	$ 158

(a) Primarily consists of customer contracts and relationships with a weighted average amortization period of 16.4 years.

After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, goodwill is an intangible asset representing the future economic benefits expected to be derived from an acquisition that are not assigned to other identifiable, separately recognizable assets. We believe the primary items that generated our goodwill are both the value of the synergies created between the acquired assets and our pre-existing assets, and our expected ability to grow the business we acquired by leveraging our pre-existing business experience. We apply a look through method of recording deferred income taxes on the outside book-tax basis differences in our investments. As a result, no deferred income taxes are recorded associated with non-deductible goodwill recorded at the investee level.

Sale of Equity Interest in SNG

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to The Southern Company (Southern Company), receiving proceeds of $1.4 billion, and the formation of a joint venture, which includes our remaining 50% interest in SNG. We used the proceeds from the sale to reduce outstanding debt (see Note 3). We recognized a pre-tax loss of $84 million on the sale of our interest in SNG which is included within “Loss on impairments and divestitures, net” on the accompanying consolidated statements of income for the three and nine months ended September 30, 2016. As a result of this transaction, we no longer hold a controlling interest in SNG or Bear Creek Storage Company, LLC (Bear Creek) (50% of which is owned by SNG) and, as such, we now account for our remaining equity interests in SNG and Bear Creek as equity investments.

3. Debt

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

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

	September 30, 2016	December 31, 2015
KMI		
Unsecured term loan facility, variable rate, due January 26, 2019(a)	$ 1,000	$ —
Senior notes, 1.50% through 8.25%, due 2016 through 2098(b)	13,326	13,346
Credit facility due November 26, 2019	—	—
Commercial paper borrowings	—	—
KMP		
Senior notes, 2.65% through 9.00%, due 2016 through 2044	19,485	19,985
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(a)	1,540	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032	1,115	1,115
Copano senior notes, 7.125%, due April 1, 2021(c)	—	332
CIG senior notes, 4.15% and 6.85%, due 2026 and 2037(d)	475	100
SNG notes, 4.40% through 8.00%, due 2017 through 2032(e)	—	1,211
Other Subsidiary Borrowings (as obligor)		
Kinder Morgan Finance Company, LLC, senior notes, 5.70% through 6.40%, due 2016 through 2036(a)	786	1,636
Hiland Partners Holdings LLC, senior notes, 5.50% and 7.25%, due 2020 and 2022	974	974
EPC Building, LLC, promissory note, 3.967%, due 2016 through 2035	435	443
Trust I preferred securities, 4.75%, due March 31, 2028	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock	100	100
Other miscellaneous debt	295	300
Total debt – KMI and Subsidiaries	39,752	41,553
Less: Current portion of debt(a)(e)(f)	2,944	821
Total long-term debt – KMI and Subsidiaries(g)	$ 36,808	$ 40,732

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(a) On January 26, 2016, we entered into a $1.0 billion three-year unsecured term loan facility with a variable interest rate, which is determined in the same manner as interest on our revolving credit facility borrowings. In January 2016, we repaid $850 million of maturing 5.70% senior notes, and in February 2016, we repaid $250 million of maturing 8.00% senior notes primarily using proceeds from the three-year term loan. Since we refinanced a portion of the maturing debt with proceeds from long-term debt, we classified $1 billion of the maturing debt within "Long-term debt" on our consolidated balance sheet as of December 31, 2015.

(b) Amount includes senior notes that are denominated in Euros and have been converted and are respectively reported above at the September 30, 2016 exchange rate of 1.1235 U.S. dollars per Euro and the December 31, 2015 exchange rate of 1.0862 U.S. dollars per Euro. For the nine months ended September 30, 2016, our debt balance increased by $47 million as a result of the change in the exchange rate of U.S. dollars per Euro. The increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in "Deferred charges and other assets" and " Other long-term liabilities and deferred credits" on our consolidated balance sheets. At the time of issuance, we entered into cross-currency swap agreements associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 5 "Risk Management—Foreign Currency Risk Management").

(c) On September 30, 2016, we repaid the $332 million principal amount of 7.125% senior notes due 2021, plus accrued interest. We recognized a $28.3 million gain from the early extinguishment of debt, included within “Interest, net” on the accompanying consolidated statements of income for the three and nine months ended September 30, 2016 consisting of an $11.8 million premium on the debt repaid and a $40.1 million gain from the write-off of unamortized purchase accounting associated with the extinguished debt. Copano continues to be a subsidiary guarantor under a cross guarantee agreement (see Note 11).

(d) On August 16, 2016, CIG completed a private offering of $375 million in principal amount of 4.15% senior notes due August 15, 2026. The net proceeds of $372 million received from the offering were used to reduce debt incurred as the result of the repayment of CIG’s senior notes that matured in 2015 and for general corporate purposes.

(e) Due to the September 1, 2016 sale of a 50% interest in SNG, we no longer consolidate SNG’s accounts in our consolidated financial statements. As of the transaction date, SNG had $1,211 million of debt outstanding (including a current portion of $500 million).

(f) Amounts include outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months (see "—Current Portion of Debt" below).

(g) Excludes our "Debt fair value adjustments" which, as of September 30, 2016 and December 31, 2015, increased our combined debt balances by $1,710 million and $1,674 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements.

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

Credit Facilities

On January 26, 2016, in accordance with the terms of our revolving credit agreement, we increased the capacity of our revolving credit agreement from $4.0 billion to $5.0 billion. The other terms of the revolving credit agreement remain the same. Our availability under this facility as of September 30, 2016 was $4,832 million, which is net of $168 million in letters of credit. Borrowings under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

Current Portion of Debt

In addition to outstanding credit facility borrowings, commercial paper borrowings, and other debt maturing within 12 months, our current portion of debt includes the current portion of the following significant series of long-term notes:

As of September 30, 2016	$600 million 6.00% notes due February 2017
	$300 million 7.50% notes due April 2017
	$355 million 5.95% notes due April 2017
	$786 million 7.00% notes due June 2017
	$749 million 7.25% notes originally due October 2020 (see "—Subsequent Event" below)
As of December 31, 2015	$500 million 3.50% notes due March 2016

Long-term Debt Issuances, Repayments and Other Significant Changes in Debt

The following are significant long-term debt issuances, repayments and other significant changes made during the nine months ended September 30, 2016:

Issuances	$1.0 billion unsecured term loan facility due 2019
	$375 million 4.15% notes due 2026
Repayments	$850 million 5.70% notes due 2016
	$500 million 3.50% notes due 2016
	$250 million 8.00% notes due 2016
	$67 million 8.25% notes due 2016
	$332 million 7.125% notes due 2021
Other significant changes	$1,211 million reduction due to the deconsolidation of SNG, including a current portion of $500 million (see Note 2)

Subsequent Event

On October 1, 2016, a portion of the proceeds from the sale of a 50% interest in SNG was used to repay the $749 million principal amount of Hiland's 7.25% senior notes due 2020, plus accrued interest. As of September 30, 2016, funds for this early extinguishment were held in escrow as a restricted deposit and included in the accompanying consolidated balance sheet within "Restricted deposits." As of September 30, 2016, we classified the $749 million of senior notes as "Current portion of debt" within the accompanying consolidated balance sheet.

4. Stockholders' Equity

Common Equity

As of September 30, 2016, 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 2015 Form 10-K.

Common 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Per common share cash dividend declared for the period	$0.125	$0.51	$0.375	$1.48
Per common share cash dividend paid in the period	$0.125	$0.49	$0.375	$1.42

On October 19, 2016, our board of directors declared a cash dividend of $0.125 per common share for the quarterly period ended September 30, 2016, which is payable on November 15, 2016 to common shareholders of record as of November 1, 2016.

Mandatory Convertible Preferred Stock

On October 30, 2015, we completed an offering of 32,000,000 depositary shares, each of which represents a 1/20th interest in a share of our 1,600,000 shares of 9.750% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share (equal to a $50 liquidation preference per depositary share). For additional information regarding our mandatory convertible preferred stock, see Note 11 to our consolidated financial statements included in our 2015 Form 10-K.

Preferred Dividends

On July 20, 2016, 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 July 26, 2016 through and including October 25, 2016, which is payable on October 26, 2016 to mandatory convertible preferred shareholders of record as of October 11, 2016.

5. 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 certain of these risks. In addition, prior to May 2016, we had power forward and swap contracts related to legacy operations of acquired businesses.

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Energy Commodity Price Risk Management

As of September 30, 2016, 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	(19.4)	MMBbl
Crude oil basis	(2.2)	MMBbl
Natural gas fixed price	(27.5)	Bcf
Natural gas basis	(12.8)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(0.1)	MMBbl
Natural gas fixed price	(9.9)	Bcf
Natural gas basis	(3.3)	Bcf
NGL and other fixed price	(2.6)	MMBbl

As of September 30, 2016, 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 2020.

Interest Rate Risk Management

As of September 30, 2016, we had a combined notional principal amount of $9,775 million of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. As of December 31, 2015, we had a combined notional principal amount of $11,000 million of fixed-to-variable interest rate swap agreements, of which $9,700 million were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of London Interbank Offered Rate plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of September 30, 2016, 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

In connection with the issuance of our Euro denominated senior notes in March 2015 (see Note 3), we entered into $1,358 million cross-currency swap agreements to manage the related foreign currency risk 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	
		September 30, 2016	December 31, 2015	September 30, 2016	December 31, 2015
	Location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$153	$ 359	$(22)	$ (13)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	111	244	(19)	—
Subtotal		264	603	(41)	(13)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	124	111	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	614	273	—	(9)
Subtotal		738	384	—	(9)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(14)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	41	—	—	(46)
Subtotal		41	—	(14)	(52)
Total		1,043	987	(55)	(74)
Derivatives not designated as hedging contracts					
Natural gas, crude, NGL and other derivative contracts	Fair value of derivative contracts/(Other current liabilities)	4	35	(8)	(1)
Subtotal		4	35	(8)	(1)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	1	—	(11)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	—	(5)
Subtotal		—	1	—	(16)
Power derivative contracts	Fair value of derivative contracts/(Other current liabilities)	—	1	—	(17)
Subtotal		—	1	—	(17)
Total		4	37	(8)	(34)
Total derivatives		$1,047	$ 1,024	$(63)	$ (108)

Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of our derivative contracts on 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 September 30,		Nine Months Ended September 30,	
		2016	2015	2016	2015
Interest rate swap agreements	Interest, net	$(84)	$251	$315	$163
Hedged fixed rate debt	Interest, net	$81	$(283)	$(323)	$(166)

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 September 30,			Three Months Ended September 30,			Three Months Ended September 30,	
	2016	2015		2016	2015		2016	2015
Energy commodity derivative contracts	$20	$119	Revenues—Natural gas sales	$(3)	$4	Revenues—Natural gas sales	$—	$—
			Revenues—Product sales and other	34	60	Revenues—Product sales and other	(2)	(6)
			Costs of sales	(1)	(2)	Costs of sales	—	—
Interest rate swap agreements(c)	—	(4)	Interest, net	(1)	(1)	Interest, net	—	—
Cross-currency swap	30	(11)	Other, net	10	2	Other, net	—	—
Total	$50	$104	Total	$39	$63	Total	$(2)	$(6)

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)
	Nine Months		Nine Months Ended September		Nine Months Ended

	Ended September 30,			30,			September 30,	
	2016	2015		2016	2015		2016	2015
Energy commodity derivative contracts	$(64)	$72	Revenues—Natural gas sales	$ 20	$ 29	Revenues—Natural gas sales	$ —	$ —
			Revenues—Product sales and other	124	161	Revenues—Product sales and other	(7)	4
			Costs of sales	(13)	(21)	Costs of sales	—	—
Interest rate swap agreements(c)	(5)	(6)	Interest, net	(2)	(2)	Interest, net	—	—
Cross-currency swap	50	(22)	Other, net	29	25	Other, net	—	—
Total	$(19)	$44	Total	$ 158	$ 192	Total	$ (7)	$ 4

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(a) We expect to reclassify an approximate $49 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of September 30, 2016 into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

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

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

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2016	2015	2016	2015
Energy commodity derivative contracts	Revenues—Natural gas sales	$1	$6	$(4)	$9
	Revenues—Product sales and other	7	169	(7)	173
	Costs of sales	1	—	(1)	—
Interest rate swap agreements	Interest, net	(14)	—	63	—
Total(a)		$(5)	$175	$51	$182

(a) Three and nine months ended September 30, 2016 includes an approximate gain of $20 million and $59 million, respectively, associated with natural gas, crude and NGL derivative contract settlements. Three and nine months ended September 30, 2015 includes an approximate gain of $19 million and $21 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of September 30, 2016 and December 31, 2015, we had no and $2 million, respectively, of outstanding letters of credit supporting our commodity price risk management program. As of September 30, 2016, we had cash margins of $16 million posted by us as collateral and no amounts posted by our counterparties as collateral. As of December 31, 2015, we had no cash margins posted by us as collateral and cash margins of $37 million posted by our counterparties as collateral. We also use industry standard commercial agreements which allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of September 30, 2016, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one or two notches, we would not be required to post additional collateral.

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, 2015	$ 219	$ (322)	$ (358)	$ (461)
Other comprehensive (loss) gain before reclassifications	(19)	65	16	62
Gains reclassified from accumulated other comprehensive loss	(158)	—	—	(158)
Net current-period other comprehensive (loss) income	(177)	65	16	(96)
Balance as of September 30, 2016	$ 42	$ (257)	$ (342)	$ (557)

	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, 2014	$ 327	$ (108)	$ (236)	$ (17)
Other comprehensive gain (loss) before reclassifications	44	(170)	7	(119)
Gains reclassified from accumulated other comprehensive loss	(192)	—	—	(192)
Net current-period other comprehensive (loss) income	(148)	(170)	7	(311)
Balance as of September 30, 2015	$ 179	$ (278)	$ (229)	$ (328)

6. 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).

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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 September 30, 2016							
Energy commodity derivative contracts(a)	$4	$264	$ —	$ 268	$(25)	$ —	$ 243
Interest rate swap agreements	$—	$738	$ —	$ 738	$—	$ —	$ 738
Cross-currency swap agreements	$—	$41	$ —	$ 41	$(14)	$ —	$ 27
As of December 31, 2015							
Energy commodity derivative contracts(a)	$48	$589	$ 2	$ 639	$(12)	$ (37)	$ 590
Interest rate swap agreements	$—	$385	$ —	$ 385	$(8)	$ —	$ 377
Cross-currency swap agreements	$—	$—	$ —	$ —	$—	$ —	$ —

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(c)	Net amount
As of September 30, 2016							
Energy commodity derivative contracts(a)	$(10)	$(39)	$—	$ (49)	$25	$ 16	$ (8)
Interest rate swap agreements	$—	$—	$—	$ —	$—	$ —	$ —
Cross-currency swap agreements	$—	$(14)	$—	$ (14)	$14	$ —	$ —
As of December 31, 2015							
Energy commodity derivative contracts(a)	$(4)	$(10)	$(17)	$ (31)	$12	$ —	$ (19)
Interest rate swap agreements	$—	$(25)	$—	$ (25)	$8	$ —	$ (17)
Cross-currency swap agreements	$—	$(52)	$—	$ (52)	$—	$ —	$ (52)

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(a) Level 1 consists primarily of New York Mercantile Exchange natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate swaps and options. Level 3 consists primarily of power derivative contracts.

(b) Cash margin deposits held by us associated with our energy commodity contract positions and OTC swap agreements and reported within “Other current liabilities” on our accompanying consolidated balance sheets.

(c) Cash margin deposits posted by us associated with our energy commodity contract positions and OTC swap agreements and reported within “Restricted deposits” on our accompanying consolidated balance sheets.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Derivatives-net asset (liability)				
Beginning of Period	$ —	$ (37)	$ (15)	$ (61)
Total gains or (losses) included in earnings	—	(1)	(9)	(1)
Settlements	—	15	24	39
End of Period	$ —	$ (23)	$ —	$ (23)
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date	$ —	$ —	$ —	$ 2

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As of December 31, 2015, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts (which expired in April 2016), where a significant portion of fair value is calculated from underlying market data that is not readily observable. The derived values use industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value and management would not expect materially different valuation results were we to use different input amounts within reasonable ranges.

Fair Value of Financial Instruments

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

	September 30, 2016		December 31, 2015	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$41,462	$ 42,106	$43,227	$ 37,481

We used Level 2 input values to measure the estimated fair value of our outstanding debt balances as of both September 30, 2016 and December 31, 2015.

7. Reportable Segments

Financial information by segment follows (in millions):

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Revenues				
Natural Gas Pipelines				
Revenues from external customers	$2,048	$2,176	$5,900	$6,444
Intersegment revenues	2	8	4	16
CO_2	310	517	916	1,316
Terminals				
Revenues from external customers	484	469	1,436	1,395
Intersegment revenues	—	—	1	1
Products Pipelines				
Revenues from external customers	415	467	1,204	1,388
Intersegment revenues	4	—	12	1
Kinder Morgan Canada	66	68	188	193
Other	(1)	—	—	3
Total segment revenues	3,328	3,705	9,661	10,757
Other revenues	8	10	25	28
Less: Total intersegment revenues	(6)	(8)	(17)	(18)
Total consolidated revenues	$3,330	$3,707	$9,669	$10,767

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Segment EBDA(a)				
Natural Gas Pipelines	$540	$993	$2,498	$2,936
CO_2	217	29	606	605
Terminals	286	249	831	798
Products Pipelines	293	288	765	811
Kinder Morgan Canada	43	42	123	120
Other	2	(9)	(11)	(55)
Total Segment EBDA	1,381	1,592	4,812	5,215
DD&A	(549)	(617)	(1,652)	(1,725)
Amortization of excess cost of equity investments	(15)	(13)	(45)	(39)
Other revenues	8	10	25	28
General and administrative expense	(171)	(160)	(550)	(540)
Interest expense, net of unallocable interest income	(474)	(539)	(1,386)	(1,525)
Unallocable income tax expense	(363)	(90)	(698)	(470)
Total consolidated net (loss) income	$(183)	$183	$506	$944

	September 30, 2016	December 31, 2015
Assets		
Natural Gas Pipelines	$ 50,428	$ 53,704
CO_2	4,211	4,706
Terminals	9,838	9,083
Products Pipelines	8,348	8,464
Kinder Morgan Canada	1,568	1,434

Other	309	418
Total segment assets	74,702	77,809
Corporate assets(b)	6,902	6,276
Assets held for sale	—	19
Total consolidated assets	$ 81,604	$ 84,104

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(a) We evaluate performance based on each segment's EBDA. Segment EBDA includes revenues, earnings from equity investments, losses on impairments and divestitures of equity investments, net, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income), net, and losses on impairments and divestitures, net. Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, prepaid assets and deferred charges, deferred tax assets, risk management assets related to debt fair value adjustments and miscellaneous corporate assets (such as information technology and telecommunications equipment) not allocated to individual segments.

8. Income Taxes

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Income tax expense	$377	$108	$744	$521
Effective tax rate	194.3%	37.1 %	59.5 %	35.6 %

The effective tax rate for the three and nine months ended September 30, 2016 is higher than the statutory federal rate of 35% primarily due to (i) the tax impact of the sale of a 50% interest in SNG; (ii) state and foreign income taxes; and (iii) the change in the effective state tax rate as a result of the SNG sale. These increases are partially offset by dividend-received deductions from our investment in Florida Gas Pipeline (Citrus) and Plantation Pipe Line. The SNG partial sale transaction generated a taxable gain resulting from non-deductible goodwill attributable to the transaction which generated a deferred tax provision of $269 million.

The effective tax rate for the three months ended September 30, 2015 is higher than the statutory federal rate of 35% primarily due to state and foreign income taxes, partially offset by dividend-received deductions from our investment in Citrus and adjustments to our income tax reserve for uncertain tax positions.

The effective tax rate for the nine months ended September 30, 2015 is marginally higher than the statutory federal rate of 35% primarily due to state and foreign income taxes, partially offset by (i) dividend-received deductions from our investment in Citrus; (ii) the change in the effective state tax rate as a result of the Hiland acquisition; and (iii) adjustments to our income tax reserve for uncertain tax positions.

As of September 30, 2016, the total amount of unrecognized tax benefits including interest and penalties relating to uncertain tax positions is $146 million, a decrease of $27 million from the December 31, 2015 balance of $173 million. This $27 million decrease in unrecognized tax benefits resulted primarily from the settlement of a state tax audit and a certain statute of limitations expiration on another matter.

9. Litigation, Environmental and Other Contingencies

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

Federal Energy Regulatory Commission Proceedings

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers the most recent of which was filed in late 2015 with the FERC (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. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $40 million in annual rate reductions and approximately $169 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP's rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. EPNG has sought federal appellate review of Opinion 517-A. 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. All refund obligations related to the 2008 rate case were satisfied during calendar year 2015. With respect to the 2010 rate case, EPNG believes it has an appropriate reserve related to the findings in Opinions 517-A and 528-A.

Other Commercial Matters

Union Pacific Railroad Company Easements & Related Litigation

SFPP and Union Pacific Railroad Company (UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al., Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In September 2011, the trial judge determined that the annual rent payable as of January 1, 2004 was $14 million, subject to annual consumer price index increases. SFPP appealed the judgment.

By notice dated October 25, 2013, UPRR demanded the payment of $22.3 million in rent for the first year of the next ten-year period beginning January 1, 2014, which SFPP rejected.

On November 5, 2014, the Court of Appeals issued an opinion which reversed the judgment, including the award of prejudgment interest, and remanded the matter to the trial court for a determination of UPRR's property interest in its right-of-way, including whether UPRR has sufficient interest to grant SFPP's easements. UPRR filed a petition for review to the California Supreme Court which was denied. The trial court has not set a date for the retrial.

After the above-referenced decision by the California Court of Appeals which held that UPRR does not own the subsurface rights to grant certain easements and may not be able to collect rent from those easements, a purported class action lawsuit was filed in 2015 in the U.S. District Court for the Southern District of California by private landowners in California who claim to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP. Substantially similar follow-on lawsuits were filed and are pending in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which are brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, assert claims against UPRR, SFPP, KMGP, and

Kinder Morgan Operating L.P. “D” for declaratory judgment, trespass, ejectment, quiet title, unjust enrichment, accounting, and alleged unlawful business acts and practices arising from defendants’ alleged improper use or occupation of subsurface real property. SFPP views these cases as primarily a dispute between UPRR and the plaintiffs. UPRR purported to grant SFPP a network of subsurface pipeline easements along UPRR’s railroad right-of-way. SFPP relied on the validity of those easements and paid rent to UPRR for the value of those easements. We believe we have recorded a right-of-way liability sufficient to cover our potential obligation, if any, for back rent.

SFPP and UPRR have engaged in multiple disputes over the circumstances under which SFPP must pay for relocations of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In 2006, following a bench trial regarding the circumstances under which SFPP must pay for relocations, the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. The decision was affirmed on appeal. In addition, UPRR contends that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way Association (AREMA) standards in determining when relocations are necessary and in completing relocations. Each party has sought declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. In 2011, a jury verdict was reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. In 2014, the trial court entered judgment against SFPP, consistent with the jury’s verdict. On June 29, 2015, the parties entered into a confidential settlement of all of the claims relating to the project in Beaumont Hills and the case was dismissed.

Since SFPP does not know UPRR’s plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the cost (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) could have an adverse effect on our financial position, results of operations, cash flows, and our dividends to our shareholders. These effects could be even greater in the event SFPP is unsuccessful in one or more of these lawsuits.

Gulf LNG Facility Arbitration

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

Plains Gas Solutions, LLC v. Tennessee Gas Pipeline Company, L.L.C. et al.

On October 16, 2013, Plains Gas Solutions, LLC (Plains) filed a petition in the 151st Judicial District Court for Harris County, Texas (Case No. 62528) against TGP, Kinetica Partners, LLC and two other Kinetica entities. The suit arises from the sale by TGP of the Cameron System in Louisiana to Kinetica Partners, LLC on September 1, 2013. Plains alleges that defendants breached a straddle agreement requiring that gas on the Cameron System be committed to Plains' Grand Chenier gas-processing facility, that requisite daily volume reports were not provided, that TGP improperly assigned its obligations under the straddle agreement to Kinetica, and that defendants interfered with Plains' contracts with producers. The petition alleges damages of at least $100 million. Under the Amended and Restated Purchase and Sale Agreement with Kinetica, Kinetica is obligated to defend and indemnify TGP in connection with the gas commitment and reporting claims. After agreeing initially to defend and indemnify TGP against such claims, Kinetica withdrew its defense, disputed its indemnity obligation, and settled with Plains. Trial of the remaining claims against TGP is scheduled for January 2017. We intend to vigorously defend the suit and pursue Kinetica, if necessary, for indemnity and costs of defense.

Brinckerhoff v. El Paso Pipeline GP Company, LLC., et al.

In December 2011 (Brinckerhoff I), March 2012, (Brinckerhoff II), May 2013 (Brinckerhoff III) and June 2014 (Brinckerhoff IV), derivative lawsuits were filed in Delaware Chancery Court against El Paso Corporation, El Paso Pipeline GP Company, L.L.C., the general partner of EPB, and the directors of the general partner at the time of the relevant transactions. EPB was named in these lawsuits as a "Nominal Defendant." The lawsuits arise from the March 2010, November 2010, May 2012 and June 2011 drop-down transactions involving EPB's purchase of SLNG, Elba Express, CPG and interests in SNG and CIG. The lawsuits allege various conflicts of interest and that the consideration paid by EPB was excessive. Brinckerhoff I and II were consolidated into one proceeding. Motions to dismiss were filed in Brinckerhoff III and Brinckerhoff IV, and such motions remain pending. On June 12, 2014, defendants' motion for summary judgment was granted in Brinckerhoff I, dismissing the case in its entirety. Defendants' motion for summary judgment in Brinckerhoff II was granted in part, dismissing certain claims and allowing the matter to go to trial in late 2014 on the remaining claims. On April 20, 2015, the Court issued a post-trial memorandum opinion (Memorandum Opinion) in Brinckerhoff II entering judgment in favor of all of the defendants other than the general partner of EPB, but finding the general partner liable for breach of contract in connection with EPB's purchase of 49% interests in Elba and SLNG and a 15% interest in SNG in a $1.13 billion drop-down transaction that closed on November 19, 2010 (Fall Dropdown), prior to our acquisition of El Paso Corporation in 2012. In its Memorandum Opinion, the Court determined that EPB suffered damages of $171 million from the Fall Dropdown, which the Court determined to be the amount that EPB overpaid for Elba. We believe the claim is derivative in nature and was extinguished by our acquisition on November 26, 2014, pursuant to a merger agreement, of all of the outstanding common units of EPB that we did not already own. On December 2, 2015, the Court denied our motion to dismiss the remaining claims in Brinckerhoff II based upon our acquisition of all of the outstanding common units of EPB, and held that damages should be calculated by considering the unaffiliated unitholders' ownership percentage as of the effective date of the merger. Based on this ruling, the Court entered judgment on February 4, 2016 in the amount of $100.2 million plus interest at the legal rate for the period from November 15, 2010 until the date of payment, if any payment is ultimately required. We filed an appeal to the Delaware Supreme Court and Brinckerhoff filed a cross-appeal challenging the dismissal of Brinckerhoff I. The appeal has been fully briefed and oral argument was held on October 19, 2016. Execution on the judgment has been stayed until the appeal is decided. At the present time, we do not believe that an ultimate award, if any, will have a material financial impact on our Company. We continue to believe the transactions at issue were appropriate and in the best interests of EPB and we intend to continue to defend the lawsuits vigorously.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. Several of the cases have been settled or dismissed. The remaining cases, which were pending in Nevada federal court, were dismissed, but the dismissal was reversed by the 9th Circuit Court of Appeals. The U.S. Supreme Court affirmed the 9th Circuit Court of Appeals in a decision dated April 21, 2015, and the cases were then remanded to the Nevada federal court for further consideration and trial, if necessary, of numerous remaining issues. On May 24, 2016, the Court granted a motion for summary judgment dismissing one of the cases in which approximately $500 million in damages has been alleged. In the remaining cases, approximately $1.5 billion in damages have been alleged against all defendants. 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. Therefore, our costs and legal exposure related to the remaining outstanding lawsuits and claims are not currently determinable.

Kinder Morgan, Inc. Corporate Reorganization Litigation

Certain unitholders of KMP and EPB filed five putative class action lawsuits in the Court of Chancery of the State of Delaware in connection with our November 26, 2014 acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of KMP and EPB and all of the outstanding shares of KMR that we did not already own. The lawsuits were consolidated under the caption In re Kinder Morgan, Inc. Corporate Reorganization Litigation (Consolidated Case No. 10093-VCL). On December 12, 2014, the plaintiffs filed a Verified Second Consolidated Amended Class Action Complaint, which purported to assert claims on behalf of both the former EPB unitholders and the former KMP unitholders. The EPB plaintiff alleged that (i) El Paso Pipeline GP Company, L.L.C. (EPGP), the general partner of EPB, and the directors of EPGP breached duties under the EPB partnership agreement, including the implied covenant of good faith and fair dealing, by entering into the EPB Transaction; (ii) EPB, E Merger Sub LLC, KMI and individual defendants aided and abetted such breaches; and (iii) EPB, E Merger Sub LLC, KMI, and individual defendants tortiously interfered with the EPB partnership agreement by causing EPGP to breach its duties under the EPB partnership agreement.

The KMP plaintiffs alleged that (i) KMR, KMGP, and individual defendants breached duties under the KMP partnership agreement, including the implied duty of good faith and fair dealing, by entering into the KMP Transaction and by failing to adequately disclose material facts related to the transaction; (ii) KMI aided and abetted such breach; and (iii) KMI, KMP, KMR, P Merger Sub LLC, and individual defendants tortiously interfered with the rights of the plaintiffs and the putative class under the KMP partnership agreement by causing KMGP to breach its duties under the KMP partnership agreement. The complaint sought declaratory relief that the transactions were unlawful and unenforceable, reformation, rescission, rescissory or compensatory damages, interest, and attorneys' and experts' fees and costs. On December 30, 2014, the defendants moved to dismiss the complaint. On April 2, 2015, the EPB plaintiff and the defendants submitted a stipulation and proposed order of dismissal, agreeing to dismiss all claims brought by the EPB plaintiff with prejudice as to the EPB lead plaintiff and without prejudice to all other members of the putative EPB class. The Court entered such order on April 2, 2015.

On August 24, 2015, the Court issued an order granting the defendants' motion to dismiss the remaining counts of the complaint for failure to state a claim. On September 21, 2015, plaintiffs filed a notice of appeal to the Supreme Court of the State of Delaware, captioned Haynes Family Trust et al. v. Kinder Morgan G.P., Inc. et al. (Case No. 515). On March 10, 2016, the Delaware Supreme Court affirmed the dismissal of all claims on appeal and this matter is now concluded.

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 September 30, 2016 and December 31, 2015, our total reserve for legal matters was $502 million and $463 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising in our products and natural gas pipeline segments and certain corporate matters.

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 and pays a minimal fee to be part of the group. 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. After a dispute with the EPA concerning certain provision of the FS, the parties agreed that the EPA would complete the FS and that the LWG may dispute the FS within 14 days of the publication of the proposed remedy for cleanup. EPA issued the FS and the Proposed Plan on June 8, 2016. The EPA's Proposed Plan includes a combination of dredging, capping, and enhanced natural recovery. It is expected to take approximately seven years to implement at an estimated present cost of approximately $750 million. Comments on the FS and the Proposed Plan were submitted by the LWG and on our own behalf on September 7, 2016. We anticipate the EPA will issue a Record of Decision (ROD) in mid-2017. 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. The allocation process will follow the issuance of the ROD with an expected completion date of 2018. 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.

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

The Roosevelt Irrigation District sued 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. 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 now presented against KMEP and SFPP are related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. We have filed an answer, general denial, and affirmative defenses in response to the Second Amended Complaint and fact discovery is proceeding.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County and was removed in 2007 to the U.S. District Court, Southern District of California (Case No. 07CV1883WCAB). The City disclosed in discovery that it was seeking approximately $170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased its claim for damages to approximately $365 million.

On November 29, 2012, the Court issued a Notice of Tentative Rulings on the parties' summary adjudication motions. The Court tentatively granted our partial motions for summary judgment on the City's claims for water and real estate damages and the State's claims for violations of California Business and Professions Code § 17200, tentatively denied the City's motion for summary judgment on its claims of liability for nuisance and trespass, and tentatively granted our cross motion for summary judgment on such claims. On January 25, 2013, the Court rendered judgment in favor of all defendants on all claims asserted by the City.

On February 20, 2013, the City of San Diego filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit. On May 21, 2015, the Court of Appeals issued a memorandum decision which affirmed the District Court's summary judgment in our favor with respect to the City's claim under California Safe Drinking Water and Toxic Enforcement Act, but reversed both the District Court's summary judgment decision in our favor on the City's remaining claims and the District Court's decision to exclude the City's expert testimony. The Court of Appeals issued a mandate returning the case to the U.S. District Court.

On June 17, 2016, the parties entered into a settlement resolving all claims related to the historical contamination at the City's stadium property. The settlement provides for a $20 million payment to the City, a waiver and release by the City of all claims which were asserted or could have been asserted in the litigation, and an agreement by defendants to indemnify the City for additional, incremental costs, if any, incurred by the City in the redevelopment of the stadium property or the development of groundwater beneath the stadium property, that would not have been incurred but for the historical releases from the Mission Valley Terminal. By Order dated June 17, 2016, the District Court granted dismissal of the litigation.

This site remains under the regulatory oversight and order of the California Regional Water Quality Control Board (RWQCB). SFPP completed the soil and groundwater remediation at the City of San Diego's stadium property site and conducted quarterly sampling and monitoring through 2015 as part of the compliance evaluation required by the RWQCB. The RWQCB issued a notice of no further action with respect to the stadium property site on May 4, 2016. SFPP's remediation effort is now focused on its adjacent Mission Valley Terminal site.

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. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona (Case No. 3:14-08165-DGC) seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given 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.

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 (JDG) of approximately 70 cooperating parties which have entered into AOCs and are 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 are expected by the end of 2016. Under the second AOC, the JDG 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 ROD for the lower 8.3 miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. On October 5, 2016, the EPA entered into an AOC with one member of the PRP group requiring such member to spend $165 million to perform engineering and design work necessary to begin the cleanup of the lower 8.3 miles of the Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete.

In addition to the AOC with one member of the PRP group described above, the EPA has notified over 80 other PRPs, including EPEC Polymers and EPEC Oil Trust (the Notice), that the EPA intends to pursue additional agreements with other "major PRPs" and initiate negotiations over cash buyouts with parties whom the EPA does not consider "major PRPs." The Notice creates significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD, and provides no guidance as to the EPA's definition of a "major PRP" or the potential amount or range of cash buyouts. 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 earlier 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.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (SLFPA) filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against TGP, SNG and approximately 100 other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The SLFPA asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On February 13, 2015, the Court granted defendants' motion to dismiss the suit for failure to state a claim, and issued an order dismissing the SLFPA's claims with prejudice. The SLFPA filed a notice of appeal on February 20, 2015. The U.S. Court of Appeals for the Fifth Circuit heard oral argument on February 29, 2016 and we await the Court's decision.

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 (Docket No. 60-999) against TGP and 17 other energy companies, alleging that defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other 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. TGP responded to Kinetica by reasserting TGP's demand for defense and indemnity and reserving its rights. On November 12, 2015, the Plaquemines Parish Council adopted a resolution directing its legal counsel in all its Coastal Zone cases to take all actions necessary to cause the dismissal of all such cases. On April 14, 2016, following interventions in the suit by the Louisiana Department of Natural Resources and Attorney General, the Parish Council passed a resolution rescinding its November 12, 2015 resolution that had directed its counsel to dismiss the suit. We intend to continue to vigorously defend the suit.

Vermilion Parish Louisiana Coastal Zone Litigation

On July 28, 2016, the District Attorney for the 15th Judicial District of Louisiana, purporting to act on behalf of Vermilion Parish and the State of Louisiana, filed suit in the state district court for Vermilion Parish, Louisiana against TGP and 52 other energy companies, alleging that the defendants' oil and gas and transportation operations associated with the development of several fields in Vermilion Parish (Operational Areas) were conducted in violation of the Coastal Zone Management Act. The suit alleges such operations caused substantial damage to the coastal waters and nearby lands (Coastal Zone) of Vermilion Parish, resulting in the release of pollutants and contaminants into the environment, improper discharge of oil field wastes, the improper use of waste pits and failure to close such pits, and the dredging of canals, which resulted in degradation of the Operational Areas, including erosion of marshes and degradation of terrestrial and aquatic life therein. As a result of such alleged violations of the Coastal Zone Management Act, the suit seeks a judgment against the defendants awarding all appropriate damages, the payment of costs to clear, revegetate, detoxify and otherwise restore the Vermilion Parish Coastal Zone, actual restoration of the affected Coastal Zone to its original condition, and reasonable costs and attorney fees. On September 2, 2016, the case was removed to the United Stated District Court for the Western District of Louisiana. On September 20, 2016, the plaintiffs filed a motion to remand the case back to the state district court. A hearing on this motion has been continued until a decision has been reached by the U.S. Court of Appeals for the Fifth Circuit in the Southeast Louisiana Flood Protection Litigation discussed above.

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 September 30, 2016 and December 31, 2015, we have accrued a total reserve for environmental liabilities in the amount of $312 million and $284 million, respectively. In addition, as of both September 30, 2016 and December 31, 2015, we have recorded a receivable of $13 million, for expected cost recoveries that have been deemed probable.

Other Contingencies

SNG's $1,211 million of public debt continues to be subject to our guarantee pursuant to the cross guarantee agreement. As a result of our sale of a 50% equity interest in SNG, and given that we expect the Investment Grade Rating requirement imposed by Section 6(c) of the cross guarantee agreement to be satisfied, our guarantee will be released on December 2, 2016.

10. Recent Accounting Pronouncements

ASU No. 2014-09

On May 28, 2014, the FASB issued ASU Nos. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This ASU is designed to create greater comparability for financial statement users across industries and jurisdictions. The provisions of ASU No. 2014-09 include a five-step process by which entities will recognize revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which an entity expects to be entitled in exchange for those goods or services. The standard also will require enhanced disclosures, provide more comprehensive guidance for transactions such as service revenue and contract modifications, and enhance guidance for multiple-element arrangements. ASU No. 2014-09 will be effective for us as of January 1, 2018. Early adoption is permitted for the interim periods within the adoption year. We are currently reviewing the effect of this ASU on our revenue recognition and assessing the timing of our adoption.

ASU No. 2015-02
On February 18, 2015, the FASB issued ASU No. 2015-02, "Consolidation (Topic 810) - Amendments to the Consolidated Analysis." This ASU focuses on the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. We adopted ASU No. 2015-02 effective January 1, 2016 with no material impact to our financial statements.

ASU No. 2015-11

On July 22, 2015, the FASB issued ASU No. 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory." This ASU requires entities to subsequently measure inventory at the lower of cost and net realizable value, and defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. ASU No. 2015-11 will be effective for us as of January 1, 2017. We are currently reviewing the effect of ASU No. 2015-11.

ASU No. 2016-02

On February 25, 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." This ASU requires that lessees will be required to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU also will require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. ASU

2016-02 will be effective for us as of January 1, 2019. We are currently reviewing the effect of ASU No. 2016-02.

ASU No. 2016-05

On March 10, 2016, the FASB issued ASU 2016-05, “Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.” This ASU clarifies that for the purposes of applying the guidance in Topic 815, a change in the counterparty to a derivative instrument that has been designated as the hedging instrument in an existing hedging relationship would not, in and of itself, be considered a termination of the derivative instrument. We adopted ASU 2016-05 in the first quarter of 2016 with no material impact to our financial statements.

ASU No. 2016-09

On March 30, 2016, the FASB issued ASU 2016-09, “Compensation - Stock Compensation (Topic 718).” This ASU was issued as part of the FASB’s simplification initiative and affects all entities that issue share-based payment awards to their employees. This ASU covers accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. ASU No. 2016-09 will be effective for us as of January 1, 2017. We are currently reviewing the effect of ASU No. 2016-09.

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU 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 ASU No. 2016-13.

ASU No. 2016-15

On August 26, 2016, the FASB issued ASU 2016-15, “Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments (Topic 230).” This ASU is intended to reduce the diversity in practice around how certain transactions are classified within the statement of cash flows. We adopted ASU No. 2016-15 in the third quarter of 2016 with no material impact to our financial statements.

11. Guarantee of Securities of Subsidiaries

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

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

On September 30, 2016, Copano (previously reflected as a Subsidiary Issuer and Guarantor) repaid the $332 million principal amount of its 7.125% senior notes due 2021. Copano continues to be a subsidiary guarantor under the cross guarantee agreement mentioned above. For all periods presented, financial statement balances and activities for Copano are now reflected within the Subsidiary Guarantor column, and the Subsidiary Issuer and Guarantor-Copano column has been eliminated.

On September 1, 2016, we sold a 50% equity interest in SNG (see further details discussed in Note 2, “Acquisitions and Divestiture”). Subsequent to the transaction, we deconsolidated SNG and now account for our equity interest in SNG as an equity investment. Our wholly owned subsidiary which holds our interest in SNG is reflected within the Subsidiary Guarantors column of these condensed consolidating financial statements.

Excluding fair value adjustments, as of September 30, 2016, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $14,325 million, $19,485 million, and $4,947 million, respectively, of Guaranteed Notes outstanding. Included in the Subsidiary Guarantors debt balance as presented in the accompanying September 30, 2016 condensed consolidating balance sheets is approximately $171 million of capital lease obligation that is not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only.

These intercompany investments and related activity eliminate in consolidation and are presented separately in the accompanying balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities.

Effective December 31, 2015, Kinder Morgan (Delaware), Inc. and Kinder Morgan Services LLC merged into KMI. As a result of such merger, both entities are no longer Subsidiary Guarantors, and for all periods presented, financial statement balances and activities for Kinder Morgan (Delaware), Inc. and Kinder Morgan Services LLC are reflected within the Parent Issuer and Guarantor column.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended September 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor-KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 9	$ —	$ 2,953	$ 386	$ (18)	$ 3,330
Operating Costs, Expenses and Other						
Costs of sales	—	—	916	61	(6)	971
Depreciation, depletion and amortization	4	—	466	79	—	549
Other operating expenses	663	—	145	132	(12)	928
Total Operating Costs, Expenses and Other	667	—	1,527	272	(18)	2,448
Operating (loss) income	(658)	—	1,426	114	—	882
Other Income (Expense)						
Earnings from consolidated subsidiaries	963	1,004	99	14	(2,080)	—
Losses from equity investments	—	—	(213)	—	—	(213)
Interest, net	(173)	(6)	(281)	(12)	—	(472)
Amortization of excess cost of equity investments and other, net	(1)	—	(6)	4	—	(3)
Income Before Income Taxes	131	998	1,025	120	(2,080)	194
Income Tax Expense	(319)	(2)	(22)	(34)	—	(377)
Net (Loss) Income	(188)	996	1,003	86	(2,080)	(183)
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(5)	(5)
Net (Loss) Income Attributable to Controlling Interests	(188)	996	1,003	86	(2,085)	(188)
Preferred Stock Dividends	(39)	—	—	—	—	(39)
Net (Loss) Income Available to Common Stockholders	$ (227)	$ 996	$ 1,003	$ 86	$ (2,085)	$ (227)
Net (Loss) Income	$ (188)	$ 996	$ 1,003	$ 86	$ (2,080)	$ (183)
Total other comprehensive loss	(3)	(47)	(32)	(31)	110	(3)
Comprehensive (loss) income	(191)	949	971	55	(1,970)	(186)
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(5)	(5)
Comprehensive (loss) income attributable to controlling interests	$ (191)	$ 949	$ 971	$ 55	$ (1,975)	$ (191)

Condensed Consolidating Statements of Income and Comprehensive Income
for the Three Months Ended September 30, 2015
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 9	$ —	$ 3,298	$ 412	$ (12)	$ 3,707
Operating Costs, Expenses and Other						
Costs of sales	—	—	1,007	98	1	1,106
Depreciation, depletion and amortization	6	—	515	96	—	617
Other operating expenses	16	1	1,101	158	(13)	1,263
Total Operating Costs, Expenses and Other	22	1	2,623	352	(12)	2,986
Operating (loss) income	(13)	(1)	675	60	—	721
Other Income (Expense)						
Earnings from consolidated subsidiaries	498	484	40	10	(1,032)	—
Earnings from equity investments	—	—	114	—	—	114
Interest, net	(208)	23	(340)	(15)	—	(540)
Amortization of excess cost of equity investments and other, net	—	—	(5)	1	—	(4)
Income Before Income Taxes	277	506	484	56	(1,032)	291
Income Tax Expense	(91)	(2)	(14)	(1)	—	(108)
Net Income	186	504	470	55	(1,032)	183
Net Loss Attributable to Noncontrolling Interests	—	—	—	—	3	3
Net Income Attributable to Controlling Interests	$ 186	$ 504	$ 470	$ 55	$ (1,029)	$ 186
Net Income	$ 186	$ 504	$ 470	$ 55	$ (1,032)	$ 183
Total other comprehensive loss	(37)	(42)	(7)	(125)	174	(37)
Comprehensive income (loss)	149	462	463	(70)	(858)	146
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	3	3
Comprehensive income (loss) attributable to controlling interests	$ 149	$ 462	$ 463	$ (70)	$ (855)	$ 149

Condensed Consolidating Statements of Income and Comprehensive Income
for the Nine Months Ended September 30, 2016
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 26	$ —	$ 8,555	$ 1,127	$ (39)	$ 9,669
Operating Costs, Expenses and Other						
Costs of sales	—	—	2,261	197	(4)	2,454
Depreciation, depletion and amortization	13	—	1,400	239	—	1,652
Other operating expenses	712	4	1,644	600	(35)	2,925
Total Operating Costs, Expenses and Other	725	4	5,305	1,036	(39)	7,031
Operating (loss) income	(699)	(4)	3,250	91	—	2,638
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,373	2,335	174	45	(4,927)	—
Losses from equity investments	—	—	(1)	—	—	(1)
Interest, net	(519)	91	(918)	(38)	—	(1,384)
Amortization of excess cost of equity investments and other, net	—	—	(17)	14	—	(3)
Income Before Income Taxes	1,155	2,422	2,488	112	(4,927)	1,250
Income Tax Expense	(656)	(5)	(32)	(51)	—	(744)
Net Income	499	2,417	2,456	61	(4,927)	506
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(7)	(7)
Net Income Attributable to Controlling Interests	499	2,417	2,456	61	(4,934)	499
Preferred Stock Dividends	(117)	—	—	—	—	(117)
Net Income Available to Common Stockholders	$ 382	$ 2,417	$ 2,456	$ 61	$ (4,934)	$ 382
Net Income	$ 499	$ 2,417	$ 2,456	$ 61	$ (4,927)	$ 506
Total other comprehensive (loss) income	(96)	(208)	(261)	101	368	(96)
Comprehensive income	403	2,209	2,195	162	(4,559)	410
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(7)	(7)
Comprehensive income attributable to controlling interests	$ 403	$ 2,209	$ 2,195	$ 162	$ (4,566)	$ 403

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Condensed Consolidating Statements of Income and Comprehensive Income
for the Nine Months Ended September 30, 2015
(In Millions)
(Unaudited)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 28	$ —	$ 9,591	$ 1,184	$ (36)	$ 10,767
Operating Costs, Expenses and Other						
Costs of sales	—	—	2,999	280	2	3,281
Depreciation, depletion and amortization	16	—	1,446	263	—	1,725
Other operating expenses	66	39	2,560	443	(38)	3,070
Total Operating Costs, Expenses and Other	82	39	7,005	986	(36)	8,076
Operating (loss) income	(54)	(39)	2,586	198	—	2,691
Other Income (Expense)						
Earnings from consolidated subsidiaries	1,980	2,033	188	41	(4,242)	—
Earnings from equity investments	—	—	304	—	—	304
Interest, net	(512)	30	(1,013)	(29)	—	(1,524)
Amortization of excess cost of equity investments and other, net	—	—	(13)	7	—	(6)
Income Before Income Taxes	1,414	2,024	2,052	217	(4,242)	1,465
Income Tax Expense	(466)	(6)	(39)	(10)	—	(521)
Net Income	948	2,018	2,013	207	(4,242)	944
Net Loss Attributable to Noncontrolling Interests	—	—	—	—	4	4
Net Income Attributable to Controlling Interests	948	2,018	2,013	207	(4,238)	948
Net Income	$ 948	$ 2,018	$ 2,013	$ 207	$ (4,242)	$ 944
Total other comprehensive loss	(311)	(419)	(351)	(266)	1,036	(311)
Comprehensive income (loss)	637	1,599	1,662	(59)	(3,206)	633
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	4	4
Comprehensive income (loss) attributable to controlling interests	$ 637	$ 1,599	$ 1,662	$ (59)	$ (3,202)	$ 637

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Condensed Consolidating Balance Sheets as of September 30, 2016
(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	$ 171	$ —	$ 13	$ 180	$ (7)	$ 357
Other current assets - affiliates	4,577	1,153	12,268	612	(18,610)	—
All other current assets	150	165	2,508	187	(4)	3,006
Property, plant and equipment, net	264	—	30,818	7,698	—	38,780
Investments	665	2	6,567	124	—	7,358
Investments in subsidiaries	27,063	29,831	4,110	4,036	(65,040)	—
Goodwill	13,789	22	5,171	3,181	—	22,163
Notes receivable from affiliates	619	21,729	1,237	375	(23,960)	—
Deferred income taxes	6,865	—	—	—	(2,270)	4,595
Other non-current assets	272	459	4,514	100	—	5,345
Total assets	$ 54,435	$ 53,361	$ 67,206	$ 16,493	$ (109,891)	$ 81,604
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 786	$ 600	$ 1,435	$ 123	$ —	$ 2,944
Other current liabilities - affiliates	2,303	12,885	2,893	529	(18,610)	—
All other current liabilities	415	283	1,965	448	(11)	3,100
Long-term debt	14,081	19,600	4,161	676	—	38,518
Notes payable to affiliates	1,601	448	20,636	1,275	(23,960)	—
Deferred income taxes	—	—	633	1,637	(2,270)	—
All other long-term liabilities and deferred credits	643	72	890	469	—	2,074
Total liabilities	19,829	33,888	32,613	5,157	(44,851)	46,636
Stockholders' equity						
Total KMI equity	34,606	19,473	34,593	11,336	(65,402)	34,606
Noncontrolling interests	—	—	—	—	362	362
Total stockholders' Equity	34,606	19,473	34,593	11,336	(65,040)	34,968
Total Liabilities and Stockholders' Equity	$ 54,435	$ 53,361	$ 67,206	$ 16,493	$ (109,891)	$ 81,604

Condensed Consolidating Balance Sheets as of December 31, 2015
(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	$ 123	$ —	$ 12	$ 142	$ (48)	$ 229
Other current assets - affiliates	2,233	1,600	9,410	688	(13,931)	—
All other current assets	126	119	2,161	195	(6)	2,595
Property, plant and equipment, net	252	—	33,032	7,263	—	40,547
Investments	16	2	5,906	116	—	6,040
Investments in subsidiaries	27,401	28,038	3,493	3,320	(62,252)	—
Goodwill	15,089	22	5,508	3,171	—	23,790
Notes receivable from affiliates	850	21,319	2,092	358	(24,619)	—
Deferred income taxes	7,501	—	—	—	(2,178)	5,323
Other non-current assets	215	307	4,951	107	—	5,580
Total assets	$ 53,806	$ 51,407	$ 66,565	$ 15,360	$ (103,034)	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 67	$ 500	$ 132	$ 122	$ —	$ 821
Other current liabilities - affiliates	1,328	8,682	3,210	711	(13,931)	—
All other current liabilities	321	458	1,992	527	(54)	3,244
Long-term debt	13,845	20,053	7,825	683	—	42,406
Notes payable to affiliates	2,404	448	20,462	1,305	(24,619)	—
Deferred income taxes	—	—	596	1,582	(2,178)	—
Other long-term liabilities and deferred credits	722	193	909	406	—	2,230
Total liabilities	18,687	30,334	35,126	5,336	(40,782)	48,701
Stockholders' equity						
Total KMI equity	35,119	21,073	31,439	10,024	(62,536)	35,119
Noncontrolling interests	—	—	—	—	284	284
Total stockholders' Equity	35,119	21,073	31,439	10,024	(62,252)	35,403
Total Liabilities and Stockholders' Equity	$ 53,806	$ 51,407	$ 66,565	$ 15,360	$ (103,034)	$ 84,104

Condensed Consolidating Statements of Cash Flows for the Nine Months Ended September 30, 2016
(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	$ (3,023)	$ 3,903	$ 8,778	$ 681	$ (6,844)	$ 3,495
Cash flows from investing activities						
Acquisitions of assets and investments, net of cash acquired	(2)	—	(331)	—	—	(333)
Capital expenditures	(39)	—	(1,550)	(520)	—	(2,109)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,402	—	—	1,402
Sale of property, plant and equipment, investments and other net assets, net of removal costs	—	—	250	—	—	250
Contributions to investments	(343)	—	(36)	(10)	—	(389)
Distributions from equity investments in excess of cumulative earnings	1,773	298	127	—	(2,040)	158
Funding to affiliates	(2,354)	(495)	(3,650)	(529)	7,028	—
Other, net	—	(52)	37	(11)	—	(26)
Net cash used in investing activities	(965)	(249)	(3,751)	(1,070)	4,988	(1,047)
Cash flows from financing activities						
Issuances of debt	8,111	—	374	—	—	8,485
Payments of debt	(7,178)	(500)	(1,449)	(8)	—	(9,135)
Restricted cash held in escrow for debt repayment	—	—	(776)	—	—	(776)
Debt issue costs	(13)	—	(1)	(1)	—	(15)
Cash dividends - common shares	(839)	—	—	—	—	(839)
Cash dividends - preferred shares	(115)	—	—	—	—	(115)
Funding from affiliates	4,070	973	1,539	446	(7,028)	—
Contributions from parents	—	—	88	—	(88)	—
Contributions from noncontrolling interests	—	—	—	—	88	88
Distributions to parents	—	(4,127)	(4,801)	(14)	8,942	—
Distributions to noncontrolling interests	—	—	—	—	(17)	(17)
Net cash provided by (used in) financing activities	4,036	(3,654)	(5,026)	423	1,897	(2,324)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	4	—	4
Net increase in cash and cash equivalents	48	—	1	38	41	128
Cash and cash equivalents, beginning of period	123	—	12	142	(48)	229

Cash and cash equivalents, end of period	$ 171	$ —	$ 13	$ 180	$ (7)	$ 357

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Condensed Consolidating Statements of Cash Flows for the Nine Months Ended September 30, 2015
(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	$ (2,387)	$ 5,917	$ 7,140	$ 134	$ (7,297)	$ 3,507
Cash flows from investing activities						
Acquisitions of assets and investments, net of cash acquired	(1,709)	—	(210)	—	—	(1,919)
Capital expenditures	(9)	—	(2,745)	(245)	—	(2,999)
Sale of property, plant and equipment, investments and other net assets, net of removal costs	—	—	45	—	—	45
Contributions to investments	(5)	—	(62)	(7)	5	(69)
Distributions from equity investments in excess of cumulative earnings	1,060	—	113	—	(992)	181
Investment in KMP	(159)	—	—	—	159	—
Funding to affiliates	(2,765)	(7,699)	(6,273)	(518)	17,255	—
Other, net	—	16	5	18	—	39
Net cash used in investing activities	(3,587)	(7,683)	(9,127)	(752)	16,427	(4,722)
Cash flows from financing activities						
Issuances of debt	12,281	—	—	—	—	12,281
Payments of debt	(11,544)	(300)	(42)	(7)	—	(11,893)
Debt issue costs	(20)	—	—	—	—	(20)
Issuances of common shares	3,833	—	—	—	—	3,833
Cash dividends - common shares	(3,084)	—	—	—	—	(3,084)
Repurchases of warrants	(12)	—	—	—	—	(12)
Funding from affiliates	4,528	5,602	6,514	611	(17,255)	—
Contributions from parents	—	156	3	12	(171)	—
Contributions from noncontrolling interests	—	—	—	—	7	7
Distributions to parents	—	(3,706)	(4,480)	(128)	8,314	—
Distributions to noncontrolling interests	—	—	—	—	(25)	(25)
Other, net	—	(1)	—	—	—	(1)
Net cash provided by financing activities	5,982	1,751	1,995	488	(9,130)	1,086
Effect of exchange rate changes on cash and cash equivalents	—	—	—	(7)	—	(7)
Net increase (decrease) in cash and cash equivalents	8	(15)	8	(137)	—	(136)
Cash and cash equivalents, beginning of period	4	15	17	279	—	315
Cash and cash equivalents, end of period	$ 12	$ —	$ 25	$ 142	$ —	$ 179

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 2015 Form 10-K.

Results of Operations
Overview

Our management evaluates our performance primarily using the measures of Segment EBDA and, as discussed below under "—Non-GAAP Measures," distributable cash flow, or 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 interest expense, general and administrative expenses, and unallocable interest income and income taxes, as well as net income attributable to noncontrolling interests. 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.

Consolidated Earnings Results

	Three Months Ended September 30,			
	2016	2015	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$540	$993	$ (453)	(46)%
CO_2	217	29	188	648 %
Terminals	286	249	37	15 %
Products Pipelines	293	288	5	2 %
Kinder Morgan Canada	43	42	1	2 %
Other	2	(9)	11	122 %
Total Segment EBDA(b)	1,381	1,592	(211)	(13)%
DD&A	(549)	(617)	68	11 %
Amortization of excess cost of equity investments	(15)	(13)	(2)	(15)%
Other revenues	8	10	(2)	(20)%
General and administrative expense(c)	(171)	(160)	(11)	(7)%
Interest expense, net of unallocable interest income(d)	(474)	(539)	65	12 %
Income before unallocable income taxes	180	273	(93)	(34)%
Unallocable income tax expense	(363)	(90)	(273)	(303)%
Net (loss) income	(183)	183	(366)	(200)%
Net (income) loss attributable to noncontrolling interests	(5)	3	(8)	(267)%
Net (loss) income attributable to Kinder Morgan, Inc.	(188)	186	(374)	(201)%
Preferred Stock Dividends	(39)	—	(39)	n/a
Net (loss) income available to common stockholders	$(227)	$186	$ (413)	(222)%

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	Nine Months Ended September 30,		
	2016	2015	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$2,498	$2,936	$ (438)	(15)%
CO_2	606	605	1	— %
Terminals	831	798	33	4 %
Products Pipelines	765	811	(46)	(6)%
Kinder Morgan Canada	123	120	3	3 %
Other	(11)	(55)	44	80 %
Total Segment EBDA(b)	4,812	5,215	(403)	(8)%
DD&A	(1,652)	(1,725)	73	4 %
Amortization of excess cost of equity investments	(45)	(39)	(6)	(15)%
Other revenues	25	28	(3)	(11)%
General and administrative expense(c)	(550)	(540)	(10)	(2)%
Interest expense, net of unallocable interest income(d)	(1,386)	(1,525)	139	9 %
Income before unallocable income taxes	1,204	1,414	(210)	(15)%
Unallocable income tax expense	(698)	(470)	(228)	(49)%
Net income	506	944	(438)	(46)%
Net (income) loss attributable to noncontrolling interests	(7)	4	(11)	(275)%
Net income attributable to Kinder Morgan, Inc.	499	948	(449)	(47)%
Preferred Stock Dividends	(117)	—	(117)	n/a
Net income available to common stockholders	$382	$948	$ (566)	(60)%

n/a – not applicable

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, other expense (income), net, losses on impairments and divestitures, net and losses on impairments and divestitures of equity investments, net. Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes. Allocable income tax expenses included in Segment EBDA for the three months ended September 30, 2016 and 2015 were $14 million and $18 million, respectively, and for the nine months ended September 30, 2016 and 2015 were $46 million and $51 million, respectively.

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

(b) Three and nine month 2016 amounts include net decreases in earnings of $425 million and $730 million, respectively, and three and nine month 2015 amounts include net decreases in earnings of $247 million and $363 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 nine month 2016 amounts include net increases in expense of $4 million and $32 million, respectively, and three and nine month 2015 amounts include a decrease in expense of $2 million and an increase in expense of $27 million, respectively, related to the combined effect of the certain items related to general and administrative expense disclosed below in "—General and Administrative, Interest, and Noncontrolling Interests."

(d) Three and nine month 2016 amounts include net decreases in expense of $31 million and $140 million, respectively, and three and nine month 2015 amounts include an increase in expense of $15 million and a decrease in expense of $40 million, respectively, related to the combined effect of the certain items related to interest expense, net of unallocable interest income disclosed below in "—General and Administrative, Interest, and

Noncontrolling Interests."

The certain item totals reflected in footnotes (b), (c) and (d) to the tables above accounted for $138 million of the decrease in income before unallocable income taxes for the third quarter of 2016, as compared to the same prior year period (representing the difference between decreases of $398 million and $260 million in income before unallocable income taxes for the third quarters of 2016 and 2015, respectively) and a decrease of $272 million in income before unallocable income taxes for the nine months ended September 30, 2016, when compared to the same prior year period (representing the difference between decreases of $622 million and $350 million in income before unallocable income taxes for the nine months ended September 30, 2016 and 2015, respectively). After giving effect to these certain items, the remaining increases in income before unallocable income taxes from the prior year quarter and year-to-date were $45 million (8%) and $62 million (4%), respectively. The quarter-to-date increase from 2015 reflects decreased DD&A expense and interest expense, net of allocable interest income and increased results in our Terminals and Products Pipelines business segments, mostly offset by unfavorable commodity prices affecting our CO_2 business segment and unfavorable results in our Natural Gas Pipelines business segment. The year-to-date increase from 2015 reflects increased results in our Products Pipelines, Terminals, and Natural Gas Pipelines business segments and decreased DD&A expense and interest expense, net of allocable interest income, mostly offset by unfavorable commodity prices affecting our CO2 business segment. The quarter-to-date and year-to-date decreases in DD&A were primarily driven by lower DD&A in our CO2 business segment. The quarter-to-date and year-to-date decreases in interest expense were due to lower weighted average debt balances, partially offset by a slightly higher overall weighted average interest rate on outstanding debt, respectively.

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 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, hurricane impacts 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.

Distributable Cash Flow

DCF is a significant performance measure used by us and by external users of our financial statements to evaluate our performance and to measure and estimate 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. Management uses this performance measure and believes it provides users of our financial statements a useful performance measure reflective of our business's ability to generate cash earnings to supplement the comparable GAAP measure. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. A reconciliation of DCF to net income available to common stockholders is provided in the table below. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

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 earnings before DD&A and amortization of excess cost of equity investments (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.

Reconciliation of Net Income Available to Common Stockholders to DCF

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except per share amounts)			
Net (loss) Income Available to Common Stockholders	$(227)	$186	$382	$948
Add/(Subtract):				
Certain items before book tax(a)	398	260	624	350
Book tax certain items(b)	172	(95)	70	(136)
Certain items after book tax	570	165	694	214
Noncontrolling interest certain items(c)	—	(6)	(9)	(20)
Net income available to common stockholders before certain items	343	345	1,067	1,142
Add/(Subtract):				
DD&A expense(d)	653	708	1,961	2,004
Total book taxes(e)	230	224	745	713
Cash taxes(f)	(22)	(3)	(61)	(19)
Other items(g)	11	7	31	23
Sustaining capital expenditures(h)	(134)	(152)	(379)	(397)
DCF	$1,081	$1,129	$3,364	$3,466
Weighted average common shares outstanding for dividends(i)	2,239	2,210	2,237	2,189
DCF per common share	$0.48	$0.51	$1.50	$1.58
Declared dividend per common share	$0.125	$0.510	$0.375	$1.480

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(a) Consists of certain items summarized in footnotes (b) through (d) to the "—Results of Operations—Consolidated Earnings Results" tables 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, Interest, and Noncontrolling Interests."

(b) Represents income tax provision on certain items, plus discrete income tax certain items. For the three and nine months ended September 30, 2016, discrete income tax items included a $276 million increase in tax expense primarily due to the impact of the sale of a 50% interest in SNG discussed in Note 8 "Income Taxes" to our consolidated financial statements.

(c) Represents noncontrolling interests share of certain items.

(d) Includes DD&A and amortization of excess cost of equity investments. Three and nine month 2016 amounts also include $89 million and $264 million, respectively, and three and nine month 2015 amounts also include $78 million and $240 million, respectively, of our share of certain equity investees' DD&A.

(e) Excludes book tax certain items and includes income tax allocated to the segments. Three and nine month 2016 amounts also include $25 million and $71 million, respectively, and three and nine month 2015 amounts also include $21 million and $56 million, respectively, of our share of taxable equity investees' book tax expense.

(f) Three and nine month 2016 amounts include $(25) million and $(59) million, respectively, and three and nine month 2015 amounts include $(2) million and $(8) million, respectively, of our share of taxable equity investees' cash taxes. The nine months ended September 30, 2015 also excludes a $195 million income tax refund received.

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

(h) Three and nine month 2016 amounts include $(24) million and $(66) million, respectively, and three and nine month 2015 amounts include $(16) million and $(50) million, respectively, of our share of equity investees' sustaining capital expenditures.

(i) Includes restricted stock awards that participate in common share dividends and dilutive effect of warrants, as applicable.

Segment Earnings Results

Natural Gas Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$2,050	$2,184	$5,904	$6,460
Operating expenses	(1,199)	(1,289)	(3,142)	(3,688)
(Loss) gain on impairments and divestitures, net(b)	(78)	2	(199)	(90)
Other income	—	—	—	3
Earnings from equity investments(b)	111	91	273	264
Loss on impairments of equity investments(b)	(350)	—	(356)	(26)
Interest income and Other, net	8	6	23	18
Income tax expense	(2)	(1)	(5)	(5)
Segment EBDA(b)	540	993	2,498	2,936
Certain items(b)	417	(18)	547	91
Segment EBDA before certain items	$957	$975	$3,045	$3,027

Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(115)	(5)%	$(538)	(8)%
Segment EBDA before certain items	$(18)	(2)%	$18	1 %

Natural gas transport volumes (BBtu/d)(c)	28,144	28,438	28,162	28,076
Natural gas sales volumes (BBtu/d)(d)	2,438	2,445	2,350	2,416
Natural gas gathering volumes (BBtu/d)(e)	2,935	3,541	3,044	3,554
Crude/condensate gathering volumes (MBbl/d)(f)	283	343	310	340

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Certain items affecting Segment EBDA

(a) Three and nine month 2016 amounts include decreases in revenue of $2 million and $34 million, respectively, and three and nine month 2015 amounts include increases in revenue of $17 million and $23 million, respectively, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. Nine month 2016 amount also includes an increase in revenue of $39 million associated with revenue collected on a customer's early buyout of a long-term natural gas storage contract.

(b) In addition to the revenue certain items described in footnote (a) above: three and nine month 2016 amounts also include (i) a $350 million impairment of our equity investment in MEP; (ii) an $84 million pre-tax loss on the sale of a 50% interest in our SNG natural gas pipeline system; (iii) an increase in earnings of $18 million related to the early termination of a customer contract at an equity investee; and (iv) an increase in earnings of $1 million and a decrease in earnings $17 million, respectively, from other certain items. Nine month 2016 amount also includes decreases in earnings of (i) $106 million of project write-offs; and (ii) $13 million related to an equity investment impairment. Three and nine month 2015 amounts also include increases in earnings of $1 million and $4 million, respectively, from other certain items. Nine month 2015 amount also includes a decrease in earnings of (i) $102 million related to certain losses on impairments and divestitures; and (ii) $26 million of impairments on equity investments, partially offset by an increase in earnings of $10 million related to a gain on the sale of a long-lived asset.

Other

(c) Includes pipeline volumes for Kinder Morgan North Texas Pipeline LLC, Monterrey, TransColorado Gas Transmission Company LLC (TransColorado), MEP, KMLP, Fayetteville Express Pipeline LLC, TGP, EPNG, South Texas Midstream, the Texas Intrastate Natural Gas Pipeline operations, CIG, Wyoming Interstate Company, L.L.C., CPG, SNG, Elba Express, Sierrita Gas Pipeline LLC, Natural Gas Pipeline Company of America LLC, Citrus and Ruby Pipeline, L.L.C. Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included at our ownership share for the entire period, however, EBDA contributions from acquisitions are included only for the periods subsequent to their acquisition.

(d) Represents volumes for the Texas Intrastate Natural Gas Pipeline operations and Kinder Morgan North Texas Pipeline LLC.

(e) Includes Oklahoma Midstream, South Texas Midstream, Eagle Ford Gathering LLC, North Texas Midstream, Camino Real Gathering Company, L.L.C. (Camino Real), Kinder Morgan Altamont LLC, KinderHawk Field Services LLC (KinderHawk), Endeavor, Bighorn Gas Gathering L.L.C., Webb Duval Gatherers, Fort Union Gas Gathering L.L.C., EagleHawk Field Services LLC (EagleHawk), Red Cedar Gathering Company and Hiland Midstream throughput volumes. Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included at our ownership share for the entire period.

(f) Includes Hiland Midstream, EagleHawk and Camino Real. Joint Venture throughput is reported at our ownership share. Volumes for
acquired pipelines are included at our ownership share for the entire period.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and nine month periods ended September 30, 2016 and 2015:

Three months ended September 30, 2016 versus Three months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
SNG	$(24)	(23)%	$(48)	(34)%
South Texas Midstream	(14)	(17)%	(60)	(18)%
KinderHawk	(10)	(33)%	(10)	(29)%
CIG	(9)	(13)%	(9)	(10)%
KMLP	(8)	(133)%	(8)	(100)%
EPNG	(8)	(7)%	(17)	(10)%
CPG	(5)	(38)%	(5)	(28)%
TransColorado	(3)	(43)%	(4)	(44)%
TGP	45	21 %	49	17 %
Hiland Midstream	13	35 %	(9)	(6)%
Texas Intrastate Natural Gas Pipeline Operations	11	15 %	3	— %
All others (including eliminations)	(6)	(3)%	3	2 %
Total Natural Gas Pipelines	$(18)	(2)%	$(115)	(5)%

Nine months ended September 30, 2016 versus Nine months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
SNG	$(30)	(9)%	$(57)	(13)%
South Texas Midstream	(43)	(17)%	(190)	(20)%
KinderHawk	(39)	(37)%	(40)	(33)%
CIG	(19)	(8)%	(20)	(7)%
KMLP	(23)	(135)%	(25)	(100)%
EPNG	—	— %	(8)	(2)%
CPG	(17)	(39)%	(18)	(31)%
TransColorado	(11)	(48)%	(12)	(43)%
TGP	151	22 %	186	21 %
Hiland Midstream	53	56 %	25	7 %
Texas Intrastate Natural Gas Pipeline Operations	10	4 %	(365)	(16)%
All others (including eliminations)	(14)	(2)%	(14)	(2)%
Total Natural Gas Pipelines	$18	1 %	$(538)	(8)%

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 nine month periods ended September 30, 2016 and 2015:

- decreases of $24 million (23%) and $30 million (9%), respectively, from SNG primarily due to our sale of 50% interest in SNG to Southern Company on September 1, 2016;

- decreases of $14 million (17%) and $43 million (17%), respectively, from South Texas Midstream primarily due to lower volumes, which resulted in decreases in revenue of approximately $60 million and $190 million, respectively, partially offset by decreases in costs of sales;
- decreases of $10 million (33%) and $39 million (37%), respectively, from KinderHawk due to lower volumes;
- decreases of $9 million (13%) and $19 million (8%), respectively, from CIG primarily due to a recent rate case settlement and lower firm reservation revenues due to contract expirations and contract renewals at lower rates;
- decreases of $8 million (133%) and $23 million (135%), respectively, from KMLP as a result of a customer contract buyout in the fourth quarter of 2015;
- decrease of $8 million (7%) and flat, respectively, from EPNG. The quarter-to-date decrease was largely due to increased pipeline integrity costs. Year-to-date results were affected by an increase in transportation revenues from capacity sales in the Permian and mainline, offset by increased pipeline integrity costs. Revenues for both quarter-to-date and year-to-date were also lower due to decreased natural gas sales, which were largely offset by the associated cost of sales;
- decreases of $5 million (38%) and $17 million (39%), respectively, from CPG primarily due to lower transport revenues as a result of contract expirations;
- decreases of $3 million (43%) and $11 million (48%), respectively, from TransColorado primarily due to lower transport revenues as a result of contract expirations;
- increases of $45 million (21%) and $151 million (22%), respectively, from TGP primarily due to expansion projects placed in service during 2015 and favorable 2016 firm transport revenues;
- increases of $13 million (35%) and $53 million (56%), respectively, from Hiland Midstream primarily due to favorable margins on renegotiated contracts, along with results of a full nine months from our February 2015 Hiland acquisition; and
- increases of $11 million (15%) and $10 million (4%), respectively, from our Texas intrastate natural gas pipeline operations (including the operations of its Kinder Morgan Tejas, Border, Kinder Morgan Texas, North Texas and Mier-Monterrey Mexico pipeline systems) primarily due to higher storage margins partially offset by lower transportation margins as a result of lower volumes. The year-to-date decrease in revenues of $365 million resulted primarily from a decrease in sales revenue due to lower commodity prices which was largely offset by a corresponding decrease in costs of sales.

CO2

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$310	$517	$916	$1,316
Operating expenses	(102)	(104)	(302)	(328)
Loss on impairments and divestitures, net(b)	—	(388)	(20)	(397)
Earnings from equity investments(b)	9	5	14	17
Income tax expense	—	(1)	(2)	(3)
Segment EBDA(b)	217	29	606	605
Certain items(b)	12	253	73	244
Segment EBDA before certain items	$229	$282	$679	$849
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(60)	(16)%	$(207)	(18)%
Segment EBDA before certain items	$(53)	(19)%	$(170)	(20)%
Southwest Colorado CO_2 production (gross)(Bcf/d)(c)	1.2	1.2	1.2	1.2
Southwest Colorado CO_2 production (net)(Bcf/d)(c)	0.6	0.6	0.6	0.6
SACROC oil production (gross)(MBbl/d)(d)	28.9	32.5	29.7	34.4
SACROC oil production (net)(MBbl/d)(e)	24.1	27.1	24.8	28.7
Yates oil production (gross)(MBbl/d)(d)	17.9	18.9	18.5	18.9
Yates oil production (net)(MBbl/d)(e)	7.9	7.6	8.2	8.2
Katz, Goldsmith, and Tall Cotton oil production (gross)(MBbl/d)(d)	6.9	6.0	6.9	5.6
Katz, Goldsmith and Tall Cotton oil production (net)(MBbl/d)(e)	5.8	5.0	5.8	4.7
NGL sales volumes (net)(MBbl/d)(e)	10.6	10.5	10.3	10.3
Realized weighted-average oil price per Bbl(f)	$62.12	$74.18	$61.27	$73.19
Realized weighted-average NGL price per Bbl(g)	$18.03	$16.29	$16.42	$18.96

Certain items affecting Segment EBDA

(a) Three and nine month 2016 amounts include unrealized losses of $12 million and $40 million, respectively, and three and nine month 2015 amounts include unrealized gains of $135 million and $143 million, respectively, related to derivative contracts used to hedge forecasted commodity sales. Nine month 2015 amount also includes a favorable adjustment of $10 million related to carried working interest at McElmo Dome.

(b) In addition to the revenue certain items described in footnote (a) above: nine month 2016 amount also includes a decrease of $12 million in equity earnings for our share of a project write-off recorded by an equity investee and a $21 million increase in expense related to source and transportation project write-offs, and three and nine month 2015 amounts also include decreases in earnings for both periods of a $378 million impairment charge associated with our Goldsmith oil and gas field driven primarily by lower crude prices, and a $10 million impairment charge associated with our Cottonwood Canyon CO_2 source project. Nine month 2015 amount also includes a decrease in earnings of $9 million related to an impairment charge associated with the pending sale of excess construction pipe.

Other

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

(d) Represents 100% of the production from the field. We own 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, a 100% interest in the Tall Cotton field and a 99% working interest in the Goldsmith Landreth unit.

(e) Net after royalties and outside working interests.

(f) Includes all crude oil production properties.

(g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and nine month periods ended September 30, 2016 and 2015.

Three months ended September 30, 2016 versus Three months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(7)	(9)%	$(10)	(10)%
Oil and Gas Producing Activities	(46)	(23)%	(52)	(17)%
Intrasegment eliminations	—	—%	2	17%
Total CO2	$(53)	(19)%	$(60)	(16)%

Nine months ended September 30, 2016 versus Nine months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(21)	(9)%	$(29)	(10)%
Oil and Gas Producing Activities	(149)	(25)%	(188)	(20)%
Intrasegment eliminations	—	—%	10	27%
Total CO2	$(170)	(20)%	$(207)	(18)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the significant factors driving Segment EBDA before certain items in the comparable three and nine month periods ended September 30, 2016 and 2015, which factors include lower revenues of $49 million and $166 million, respectively, from lower commodity prices and $13 million and $50 million, respectively, of decreased volumes, partially offset by (i) $7 million and $37 million, respectively, in reduced operating costs, and severance and ad valorem tax expenses; and (ii) $2 million and $9 million, respectively, primarily related to increased earnings from an equity investee.

Terminals

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$484	$469	$1,437	$1,396
Operating expenses	(194)	(221)	(580)	(599)
Loss on impairments and divestitures, net(b)	(4)	—	(21)	—
Other income (expense)	—	1	—	(1)
Earnings from equity investments	6	7	17	16
Interest income and Other, net	2	1	3	7
Income tax expense	(8)	(8)	(25)	(21)
Segment EBDA(b)	286	249	831	798
Certain items(b)	(1)	14	6	—
Segment EBDA before certain items	$285	$263	$837	$798

Change from prior period	Increase/(Decrease)			
Revenues before certain items	$15	3 %	$38	3 %
Segment EBDA before certain items	$22	8 %	$39	5 %

Bulk transload tonnage (MMtons)(c)	17.2	16.9	46.3	48.9
Ethanol (MMBbl)	17.3	15.0	48.9	47.3
Liquids leasable capacity (MMBbl)	88.9	81.5	88.9	81.5
Liquids utilization %(d)	95.6 %	93.1 %	95.6 %	93.1 %

Certain items affecting Segment EBDA

(a) Three and nine month 2016 amounts include increases in revenue of $6 million and $22 million, respectively, and three and nine month 2015 amounts include increases in revenue of $6 million and $19 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers.

(b) In addition to the revenue certain items described in footnote (a) above: three and nine month 2016 amounts also include increases in expense of $5 million and $8 million, respectively, related to other certain items, and nine month 2016 amount also includes $20 million related to losses on impairments and divestitures, and three and nine month 2015 amounts also include (i) increases in expenses of $22 million for both periods due to a certain coal customer's bankruptcy related to revenues recognized in prior years but not yet collected; (ii) increases in earnings of $1 million and $4 million, respectively, associated with a liability adjustment related to a litigation matter; and (iii) an increase in earnings of $1 million and a decrease in earnings of $1 million, respectively from other certain items.

Other

(c) Includes our proportionate share of joint venture tonnage.

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

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and nine month periods ended September 30, 2016 and 2015.

Three months ended September 30, 2016 versus Three months ended September 30, 2015

	Segment EBDA	Revenues before certain items

	before certain items increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$15	65 %	$ 21	55 %
Lower River	7	70 %	(1)	(3)%
Northeast	3	9 %	4	7 %
Gulf Liquids	1	2 %	3	4 %
Gulf Bulk	(9)	(36)%	(12)	(29)%
All others (including intrasegment eliminations and unallocated income tax expenses)	5	4 %	—	— %
Total Terminals	$22	8 %	$ 15	3 %

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Nine months ended September 30, 2016 versus Nine months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$37	53 %	$ 52	46 %
Lower River	(4)	(8)%	(11)	(11)%
Northeast	10	13 %	13	9 %
Gulf Liquids	15	8 %	18	7 %
Gulf Bulk	(32)	(41)%	(37)	(29)%
All others (including intrasegment eliminations and unallocated income tax expenses)	13	4 %	3	— %
Total Terminals	$39	5 %	$ 38	3 %

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three and nine month periods ended September 30, 2016 and 2015:

- increases of $15 million (65%) and $37 million (53%), respectively, from our Marine Operations related to the incremental earnings from the December 2015, May 2016 and July 2016 deliveries of the Jones Act tankers, the "Lone Star State," "Magnolia State," and "Garden State," respectively, and increased charter rates on the "Empire State" and "Evergreen State" Jones Act tankers, partially offset by off-hire days on the "Pelican State" Jones Act tanker;
- increase of $7 million (70%) and a decrease of $4 million (8%), respectively, from our Lower River terminals, primarily due to an $8 million write-off of a certain coal customer's accounts receivable which occurred in the third quarter of 2015 offset by the decreased revenues and earnings of $3 million and $17 million, respectively, due to certain coal customer bankruptcies;
- increases of $3 million (9%) and $10 million (13%), respectively, from our Northeast terminals, primarily due to contributions from two terminals acquired as part of the BP Products North America Inc. acquisition which was completed in February 2016;
- increases of $1 million (2%) and $15 million (8%), respectively, from our Gulf Liquids terminals, primarily related to higher volumes as a result of various expansion projects, including marine infrastructure improvements at our Galena Park, Pasadena, and North Docks terminals, as well as higher rates and ancillary service activities on existing business;
- decreases of $9 million (36%) and $32 million (41%), respectively, from our Gulf Bulk terminals, driven by decreased revenues and earnings of $10 million and $35 million, respectively, due to certain coal customer bankruptcies.

Products Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues(a)	$419	$467	$1,216	$1,389
Operating expenses(b)	(138)	(188)	(432)	(607)
Loss on impairments and divestitures, net(c)	(1)	—	(74)	(1)
Earnings from equity investments	12	10	40	32
Gain on divestiture of equity investment(d)	—	—	12	—
Interest income and Other, net	—	2	—	5
Income tax benefit (expense)	1	(3)	3	(7)
Segment EBDA(a)(b)(c)(d)	293	288	765	811
Certain items(a)(b)(c)(d)	1	(1)	112	(4)
Segment EBDA before certain items	$294	$287	$877	$807
Change from prior period	Increase/(Decrease)			
Revenues before certain items	$(47)	(10)%	$(173)	(13)%
Segment EBDA before certain items	$7	2%	$70	9%
Gasoline (MMBbl)(e)	97.4	93.2	280.9	275.5
Diesel fuel (MMBbl)	32.9	34.1	94.7	96.7
Jet fuel (MMBbl)	27.9	26.7	79.0	77.8
Total refined product volumes (MMBbl)(f)	158.2	154.0	454.6	450.0
NGL (MMBbl)(g)	9.9	10.0	28.9	29.4
Crude and condensate (MMBbl)(h)	28.8	27.3	87.6	70.9
Total delivery volumes (MMBbl)	196.9	191.3	571.1	550.3
Ethanol (MMBbl)(i)	10.1	10.7	30.9	31.1

Certain items affecting Segment EBDA

(a) Three month 2015 amount includes an increase in revenue of $1 million related to an unrealized swap gain.

(b) Nine month 2016 amount includes increases in expense of $31 million of rate case liability estimate adjustments associated with pre-2016 revenues and $20 million related to a legal settlement. Nine month 2015 amount includes a decrease in expense of $4 million related to a certain Pacific operations litigation matter.

(c) Three and nine month 2016 amounts include $1 million and $9 million, respectively, of non-cash impairment charges related to the sale of a Transmix facility and nine month 2016 amount also includes an increase in expense of $64 million related to the Palmetto project write-off.

(d) Nine month 2016 amount includes a $12 million gain related to the sale of an equity investment.

Other

(e) Volumes include ethanol pipeline volumes.

(f) Includes Pacific, Plantation Pipe Line Company, Calnev, and Central Florida pipeline volumes. Joint venture throughput is reported at our ownership share.

(g) Includes Cochin and Cypress pipeline volumes. Joint venture throughput is reported at our ownership share.

(h) Includes Kinder Morgan Crude & Condensate, Double Eagle Pipeline LLC and Double H pipeline volumes. Joint venture throughput is
reported at our ownership share.

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

Below are the changes in both Segment EBDA before certain items and revenues before certain items, in the comparable three and nine month periods ended September 30, 2016 and 2015.

Three months ended September 30, 2016 versus Three months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
KMCC - Splitter	$3	25 %	$ 4	27 %
Crude & Condensate Pipeline	2	4 %	(1)	(2)%
Double H pipeline	2	17 %	4	27 %
Transmix	2	25 %	(59)	(50)%
Plantation Pipe Line	1	7 %	—	— %
All others (including eliminations)	(3)	(2)%	5	2 %
Total Products Pipelines	$7	2 %	$ (47)	(10)%

Nine months ended September 30, 2016 versus Nine months ended September 30, 2015

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
KMCC - Splitter	$21	95%	$ 29	116 %
Crude & Condensate Pipeline	29	22%	27	19 %
Double H pipeline	10	33%	16	42 %
Transmix	2	8 %	(261)	(62)%
Plantation Pipe Line	6	15%	—	— %
All others (including eliminations)	2	—%	16	2 %
Total Products Pipelines	$70	9 %	$ (173)	(13)%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable three and nine month periods ended September 30, 2016 and 2015:

- increases of $3 million (25%) and $21 million (95%), respectively, from our KMCC - Splitter due to first and second phases being in full operation for 2016. Start up of first phase was in March 2015 and second phase was in July 2015;
- increases of $2 million (4%) and $29 million (22%), respectively, from our Kinder Morgan Crude & Condensate Pipeline driven primarily by an increase in pipeline throughput volumes from existing customers and additional volumes associated with expansion projects;
- increases of $2 million (17%) and $10 million (33%), respectively, due to a full nine months of results from our Double H pipeline, which began operations in March 2015;
- increases of $2 million (25%) and $2 million (8%), respectively, from our Transmix processing operations. The decreases in revenues of $59 million and $261 million, respectively, and associated decreases in costs of goods sold were driven by lower sales volumes; and

- increases of $1 million (7%) and $6 million (15%), respectively, from our equity investment in Plantation Pipe Line primarily due to higher transportation revenues and lower operating costs.

Kinder Morgan Canada

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except operating statistics)			
Revenues	$66	$68	$188	$193
Operating expenses	(21)	(22)	(60)	(64)
Interest income and Other, net	3	1	12	6
Income tax expense	(5)	(5)	(17)	(15)
Segment EBDA	$43	$42	$123	$120
Change from prior period	Increase/(Decrease)			
Revenues	$(2)	(3)%	$(5)	(3)%
Segment EBDA	$1	2%	$3	3%
Transport volumes (MMBbl)(a)	30.7	29.5	88.1	86.9

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(a) Represents Trans Mountain pipeline system volumes.

For the comparable three and nine month periods of 2016 and 2015, the Kinder Morgan Canada business segment had increases in Segment EBDA of $1 million (2%) and $3 million (3%), respectively.

Other

This segment contributed earnings of $2 million and loss of $11 million for the three and nine months ended September 30, 2016, respectively, and contributed losses of $9 million and $55 million for the three and nine months ended September 30, 2015, respectively. The three and nine months ended September 30, 2016 earnings and loss included certain items which increased Segment EBDA by $4 million and $8 million, respectively; and three and nine month 2015 losses included certain items of a $1 million increase in earnings and a $32 million decrease in earnings, respectively. The nine month 2015 certain items related primarily to a certain litigation matter. After taking into effect the certain items, the losses for the three and nine months ended September 30, 2016 decreased by $8 million and $4 million, respectively, when compared with the same prior year periods.

General and Administrative, Interest, and Noncontrolling Interests

	Three Months Ended September 30,			
	2016	2015	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative expense(a)(d)	$171	$160	$11	7%
Certain items(a)	(4)	2	(6)	(300)%
Management fee reimbursement(d)	(8)	(10)	2	20%
General and administrative expense before certain items	$159	$152	$7	5%

Unallocable interest expense net of interest income and other, net(b)	$474	$539	$ (65)	(12)%
Certain items(b)	31	(15)	46	307 %
Unallocable interest expense net of interest income and other, net, before certain items	$505	$524	$ (19)	(4)%

Net income (loss) attributable to noncontrolling interests	$5	$(3)	$ 8	267 %
Noncontrolling interests associated with certain items(c)	—	6	(6)	(100)%
Net income attributable to noncontrolling interests before certain items	$5	$3	$ 2	67 %

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	Nine Months Ended September 30, 2016	2015	Increase/(decrease)	
	(In millions, except percentages)			
General and administrative expense(a)(d)	$550	$540	$ 10	2 %
Certain items(a)	(32)	(27)	(5)	(19)%
Management fee reimbursement(d)	(25)	(28)	3	11 %
General and administrative expense before certain items	$493	$485	$ 8	2 %
Unallocable interest expense net of interest income and other, net(b)	$1,386	$1,525	$ (139)	(9)%
Certain items(b)	140	40	100	250 %
Unallocable interest expense net of interest income and other, net, before certain items	$1,526	$1,565	$ (39)	(2)%
Net income (loss) attributable to noncontrolling interests	$7	$(4)	$ 11	275 %
Noncontrolling interests associated with certain items(c)	9	20	(11)	(55)%
Net income attributable to noncontrolling interests before certain items	$16	$16	$ —	— %

Certain items

(a) Three and nine month 2016 amounts include (i) a decrease in expense of $1 million and an increase in expense of $7 million, respectively, related to certain corporate legal matters; (ii) increases in expense of $1 million and $13 million, respectively, related to severance costs; and (iii) increases in expense of $4 million and $12 million, respectively, related to acquisition costs. Three and nine month 2015 amounts include increases in expense of (i) $1 million and $41 million, respectively, related to certain corporate legal matters; and (ii) $2 million and $14 million, respectively, related to costs associated with our Hiland acquisition. Partially offsetting these three and nine month 2015 increases are decreases in expense of $5 million and $28 million, respectively, related to pension credit income.

(b) Three and nine month 2016 amounts include (i) decreases in interest expense of $47 million and $84 million, respectively, related to debt fair value adjustments associated with acquisitions; and (ii) an increase in interest expense of $16 million and a decrease in interest expense of $56 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness. Three and nine month 2015 amounts include increases in interest expense of $33 million and $3 million, respectively, related to non-cash true-ups of our estimates of swap ineffectiveness and decreases in interest expense of $18 million and $53 million, respectively, related to debt fair value adjustments associated with acquisitions. Nine month 2015 amount also includes a decrease in interest expense of $13 million associated with a certain Pacific operations litigation matter and a $23 million increase in interest expense for a non-cash adjustment related to a certain legal matter.

(c) Nine month 2016 amount includes a loss of $9 million, and nine month 2015 amount includes a loss of $14 million associated with Natural Gas Pipelines segment certain items and disclosed above in "—Natural Gas Pipelines." Three and nine month 2015 amounts include a $6 million loss associated with a terminals segment certain item and disclosed above in "—Terminals."

Other

(d) Three and nine month 2016 amounts include $8 million and $25 million, respectively, and three and nine month 2015 amounts include $10 million and $28 million, respectively, of general and administrative management fee revenues from an equity investee. These amounts were recorded to the "Product sales and other" caption with the offsetting expenses primarily included in the "General and administrative" expense caption in our accompanying consolidated statements of income.

General and administrative expenses before certain items for the three and nine months ended September 30, 2016, as compared to the respective prior periods increased $7 million and $8 million, respectively. The quarter-to-date increase from 2015 was primarily driven by higher benefit costs partially offset by higher capitalized costs and lower labor expenses. The year-to-date increase from 2015 was primarily driven by higher benefit costs and lower capitalized costs partially offset by lower labor and outside services expenses.

In the table above, we report our interest expense as “net,” meaning that we have subtracted unallocated interest income. Our consolidated interest expense net of interest income and other, net before certain items for the three and nine months ended September 30, 2016, as compared to the respective prior periods decreased $19 million and $39 million, respectively. The decreases in interest expense were due to lower weighted average debt balances, partially offset by a slightly higher overall weighted average interest rate on our outstanding debt.

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of September 30, 2016 and December 31, 2015, approximately 28% and 27%, respectively, of our debt balances (excluding debt fair value adjustments) were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 5 “Risk Management—Interest Rate Risk Management” to our consolidated financial statements.

Net income attributable to noncontrolling interests, represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not owned by us. Net income attributable to noncontrolling interests before certain items for the three and nine months ended September 30, 2016 as compared to the respective prior periods increased $2 million and was flat, respectively.

Income Taxes

The $269 million and $223 million increases in tax expense for the three and nine months ended September 30, 2016 as compared to the same periods in 2015 were primarily due to the impact of the sale of a 50% interest in SNG discussed in Note 8 “Income Taxes” to our consolidated financial statements, partially offset by lower 2016 pre-tax earnings.

Liquidity and Capital Resources

General

As of September 30, 2016, we had $357 million of “Cash and cash equivalents,” an increase of $128 million (56%) from December 31, 2015. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in “—Short-term Liquidity”), and cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

We have consistently generated strong cash flow from operations, providing a source of funds of $3,495 million and $3,507 million in the first nine months of 2016 and 2015, respectively. The period-to-period decrease is discussed below in “Cash Flows—Operating Activities”. We have relied on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, and dividend payments, and during 2016, to fund our expansion capital expenditures.

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to Southern Company, receiving proceeds of approximately $1.4 billion. Inclusive of existing SNG debt, the transaction equates to an SNG total enterprise value of $4.15 billion. We used the proceeds from this transaction to reduce outstanding debt. As of September 1, 2016, SNG had $1,211 million of debt outstanding (including a current portion of $500 million) which is no longer consolidated on our balance sheet. In addition to repaying outstanding commercial paper and credit facility borrowings, proceeds from the sale of the 50% interest in SNG were also used on September 30, 2016 to repay the $332 million principal amount of Copano’s 7.125% notes due 2021, and on October 1, 2016, to repay the $749 million principal amount of Hiland’s 7.25% senior notes due 2020 (see Note 3 “Debt”).

On January 26, 2016, we announced the issuance of a new $1.0 billion unsecured term loan facility and the expansion of our revolving credit facility from $4.0 billion to $5.0 billion. The proceeds of the three-year unsecured term loan facility were used to refinance maturing long-term debt.

On August 16, 2016, CIG completed a private offering of $375 million in principal amount of 4.15% senior notes due August 15, 2026. We received net proceeds of $372 million from the offering and used the proceeds from the sale of the notes to reduce debt incurred as the result of the repayment of CIG’s senior notes that matured in 2015 and for general corporate purposes.

In general, we expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. We also expect that our current common stock dividend level will allow us to use retained cash to fund our growth projects in 2016. Moreover, by continuing to focus on high-grading our growth project backlog to allocate capital to the highest return opportunities, we do not expect to need to access the capital markets to fund our growth projects for the foreseeable future beyond 2016.

Short-term Liquidity

As of September 30, 2016, our principal sources of short-term liquidity are (i) our $5.0 billion revolving credit facility and associated $4.0 billion commercial paper program and (ii) cash from operations. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under our credit facility. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations.

Our short-term debt as of September 30, 2016 was $2,944 million, primarily consisting of $2,790 million of senior notes that mature in the next year. We intend to refinance our short-term debt through additional credit facility borrowings, commercial paper borrowings, or by issuing new long-term debt or paying down short-term debt using cash retained from operations or received from asset sales. Our short-term debt balance as of December 31, 2015 was $821 million.

We had working capital (defined as current assets less current liabilities) deficits of $2,681 million and $1,241 million as of September 30, 2016 and December 31, 2015, respectively. Our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we may periodically replace with long-term financing and/or partially pay down using retained cash from operations. The overall $1,440 million (116%) unfavorable change from year-end 2015 was primarily due to a net increase in our current portion of long term debt, offset partially by a favorable change in cash and restricted deposits resulting from proceeds received from our sale of a 50% interest in SNG. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities.

Capital Expenditures

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

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

Our capital expenditures for the nine months ended September 30, 2016, and the amount we expect to spend for the remainder of 2016 to sustain and grow our businesses are as follows:

	Nine Months Ended September 30, 2016	2016 Remaining	Total
	(In millions)		
Sustaining capital expenditures(a)	$379	$ 170	$549
Discretionary capital expenditures(b)(c)	$2,121	$ 602	$2,723

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(a) Nine-months 2016, 2016 Remaining, and Total 2016 amounts include $66 million, $28 million, and $94 million, respectively, for our proportionate share of sustaining capital expenditures of unconsolidated joint ventures.

(b) Nine-months 2016 amount includes an increase of $588 million of discretionary capital expenditures of unconsolidated joint ventures (including a NGPL Holdings LLC contribution) and acquisitions (primarily BP terminals acquisition) and divestitures and a decrease of a combined $263 million of net changes from accrued capital expenditures and contractor retainage.

(c) 2016 Remaining amount includes our contributions to certain unconsolidated joint ventures and small acquisitions and divestitures, net of contributions estimated from unaffiliated joint venture members for consolidated investments.

Off Balance Sheet Arrangements

Other than commitments for the purchase of property, plant and equipment discussed below, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2015 in our 2015 Form 10-K. KMI expects to be released from its guarantor obligation with respect to SNG's $1,211 million of public notes in December of 2016.

Commitments for the purchase of property, plant and equipment as of September 30, 2016 and December 31, 2015 were $1,567 million and $1,229 million, respectively. The $338 million increase is primarily the result of our increase in various capital commitments associated with our natural gas pipeline business segment.

Cash Flows

Operating Activities

The net decrease of $12 million in cash provided by operating activities for the nine months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $139 million decrease in cash from overall net income after adjusting our period-to-period $438 million decrease in net income for non-cash items primarily consisting of the following: (i) net losses on impairments and divestitures (see discussion above in "—Results of Operations"); (ii) losses on impairment and disposals of equity investments primarily due to the impairment of our equity investment in MEP (see discussion above in "—Results of Operations"); (iii) changes in DD&A expenses (including amortization of excess cost of equity investments) and deferred income taxes; and (iv) change in earnings from equity investments; and
- a $127 million increase associated with net changes in non-current assets and liabilities offset partially by a net decrease in working capital items. The net increase in non-current assets and liabilities was driven, in large part, by realized gains on derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. The decrease in working capital was primarily due to a non-recurring $195 million income tax refund and a $73 million payment

under a take-or-pay contract that we received in 2015, offset partially by higher cash flow due to the timing of payments from our trade payables.

Investing Activities

The $3,675 million net decrease in cash used in investing activities for the nine months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $1,586 million decrease in expenditures for acquisitions and investments in 2016 compared to the respective 2015 period. The overall decrease in acquisitions was primarily related to the $324 million portion of the purchase price we paid in 2016 for the BP terminals acquisition, versus $1,706 million (net of cash assumed) and $158 million we paid for the Hiland and Vopak acquisitions, respectively, in the 2015 period;
- a $1,402 million net increase in cash due to proceeds from the sale of a 50% equity interest in SNG;

- an $890 million reduction in capital expenditures; and
- a $205 million increase in cash from proceeds of sales of other long-lived assets; partially offset by,
- a $320 million increase in contributions to equity investments in 2016 compared to the respective 2015 period, primarily due to a $312 million contribution to our 50% investment in NGPL Holdings LLC in 2016; and
- a $101 million decrease in cash primarily due to unfavorable changes in restricted deposits associated with our hedging activities.

Financing Activities

The net decrease of $3,410 million in cash provided by financing activities for the nine months of 2016 compared to the respective 2015 period was primarily attributable to:

- a $3,833 million decrease in cash resulting from the issuances of our Class P shares under our equity distribution agreement in 2015 and no activity in 2016;
- a $1,033 million net decrease in net debt proceeds. See Note 3 “Debt” for further information regarding our debt activity;
- a $776 million decrease in cash resulting from cash held in “Restricted deposits” at September 30, 2016 for an October 1, 2016 debt repayment; and
- a $115 million decrease in cash due to dividends paid to our mandatory convertible preferred shareholders in 2016; partially offset by,
- a $2,245 million reduction in dividend payments paid to our common shareholders; and
- an $81 million increase in contributions provided by noncontrolling interests, primarily reflecting the contributions received from BP for its 25% share of a newly formed joint venture.

Common Dividends

We expect to declare common dividends of $0.50 per share on our common stock for 2016 ($0.125/quarter).

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
December 31, 2015	$ 0.125	January 20, 2016	February 1, 2016	February 16, 2016
March 31, 2016	$ 0.125	April 20, 2016	May 2, 2016	May 16, 2016
June 30, 2016	$ 0.125	July 20, 2016	August 1, 2016	August 15, 2016
September 30, 2016	$ 0.125	October 19, 2016	November 1, 2016	November 15, 2016

The actual amount of common dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. “Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.” of our 2015 Form 10-K. All of these matters will be taken into consideration by our board of directors in declaring dividends.

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

Preferred Dividends

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

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
October 30, 2015 through January 25, 2016	$23.291667	November 17, 2015	January 11, 2016	January 26, 2016
January 26, 2016 through April 25, 2016	$24.375000	January 20, 2016	April 11, 2016	April 26, 2016
April 26, 2016 through July 25, 2016	$24.375000	April 20, 2016	July 11, 2016	July 26, 2016
July 26, 2016 through October 25, 2016	$24.375000	July 20, 2016	October 11, 2016	October 26, 2016

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk.
There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2015, in Item 7A in our 2015 Form 10-K. For more information on our risk management activities, see Item 1, Note 5 “Risk Management” to our consolidated financial statements.

Item 4. Controls and Procedures.
As of September 30, 2016, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.
There have been no material changes in the risk factors disclosed in Part I, Item 1A in our 2015 Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95.1 to this quarterly report.

Item 5. Other Information.

None.

Item 6. Exhibits.

3.1 *	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10 Q for the three months ended June 30, 2015 (file No. 001-35081)).
3.2 *	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8 K, filed January 26, 2016 (File No. 001-35081)).
10.1	Cross Guarantee Agreement, dated as of November 26, 2014, among Kinder Morgan, Inc. and certain of its subsidiaries, with schedules updated as of September 30, 2016.
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95.1	Mine Safety Disclosures.
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three and nine months ended September 30, 2016 and 2015; (ii) our Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2016 and 2015; (iii) our Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015; (iv) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2016 and 2015; (v) our Consolidated Statements of Stockholders' Equity for the nine months ended September 30, 2016 and 2015; and (vi) the notes to our Consolidated Financial Statements.

* Asterisk indicates exhibit incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

SIGNATURE

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

KINDER MORGAN, INC.
Registrant

Date:	October 21, 2016	By:	/s/ Kimberly A. Dang
			Kimberly A. Dang
			Vice President and Chief Financial Officer
			(principal financial and accounting officer)

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