KINDER MORGAN, INC.
Form 10-K
February 16, 2016

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

Form 10-K

[X]	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015
or

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

For the transition period from _____to_____
Commission file number: 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

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

Title of each class	Name of each exchange on which registered
Class P Common Stock	New York Stock Exchange
Warrants to Purchase Class P Common Stock	New York Stock Exchange
Depositary Shares, each representing a 1/20th interest in a share of 9.75% Series A Mandatory Convertible Preferred Stock	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes o No þ

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 Website, 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K(§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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 (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
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 Securities Exchange Act of 1934). Yes o No þ

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2015 was approximately $69,734,282,635. As of February 11, 2016, the registrant had 2,231,555,976 Class P shares outstanding.

KINDER MORGAN, INC. AND SUBSIDIARIES
TABLE OF CONTENTS

		Page Number
	Glossary	4
	Information Regarding Forward-Looking Statements	5
	PART I	
Items 1. and 2.	Business and Properties	6
	General Development of Business	7
	Organizational Structure	7
	Recent Developments	7
	Financial Information about Segments	11
	Narrative Description of Business	11
	Business Strategy	11
	Business Segments	11
	Natural Gas Pipelines	12
	CO_2	14
	Terminals	17
	Products Pipelines	18
	Kinder Morgan Canada	18
	Other	19
	Major Customers	19
	Regulation	19
	Environmental Matters	23
	Other	26
	Financial Information about Geographic Areas	26
	Available Information	27
Item 1A.	Risk Factors	27
Item 1B.	Unresolved Staff Comments	36
Item 3.	Legal Proceedings	36
Item 4.	Mine Safety Disclosures	36
	PART II	
Item 5.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	37
Item 6.	Selected Financial Data	38
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	39
	General	39
	Critical Accounting Policies and Estimates	41
	Results of Operations	45
	Income Taxes—Continuing Operations	63
	Liquidity and Capital Resources	63
	Recent Accounting Pronouncements	68

KINDER MORGAN, INC. AND SUBSIDIARIES
TABLE OF CONTENTS (continued)

Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	69
	Energy Commodity Market Risk	69
	Interest Rate Risk	70
Item 8.	Financial Statements and Supplementary Data	71
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	71
Item 9A.	Controls and Procedures	71
Item 9B.	Other Information	72
	PART III	
Item 10.	Directors, Executive Officers and Corporate Governance	72
Item 11.	Executive Compensation	72
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	72
Item 13.	Certain Relationships and Related Transactions, and Director Independence	72
Item 14.	Principal Accounting Fees and Services	72
	PART IV	
Item 15.	Exhibits, Financial Statement Schedules	72
	Index to Financial Statements	77
Signatures		163

KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

Calnev	=	Calnev Pipe Line LLC	$KMCO_2$	=	Kinder Morgan CO_2 Company, L.P.
CIG	=	Colorado Interstate Gas Company, L.L.C.	KMEP	=	Kinder Morgan Energy Partners, L.P.
Copano	=	Copano Energy, L.L.C.	KMGP	=	Kinder Morgan G.P., Inc.
CPG	=	Cheyenne Plains Gas Pipeline Company, L.L.C.	KMI	=	Kinder Morgan Inc. and its majority-owned and/or controlled subsidiaries
EagleHawk	=	EagleHawk Field Services LLC			
Eagle Ford	=	Eagle Ford Gathering LLC	KMLP	=	Kinder Morgan Louisiana Pipeline LLC
Elba Express	=	Elba Express Company, L.L.C.	KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
ELC	=	Elba Liquefaction Company, L.L.C.			
EP	=	El Paso Corporation and its its majority-owned and controlled subsidiaries	KMR	=	Kinder Morgan Management, LLC
			MEP	=	Midcontinent Express Pipeline LLC
EPB	=	El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	NGPL	=	Natural Gas Pipeline Company of America LLC
			SFPP	=	SFPP, L.P.
EPNG	=	El Paso Natural Gas Company, L.L.C.	SLNG	=	Southern LNG Company, L.L.C.
EPPOC	=	El Paso Pipeline Partners Operating Company, L.L.C.	SNG	=	Southern Natural Gas Company, L.L.C.
			TGP	=	Tennessee Gas Pipeline Company, L.L.C.
FEP	=	Fayetteville Express Pipeline LLC	WIC	=	Wyoming Interstate Company, L.L.C.
Hiland	=	Hiland Partners, LP	WYCO	=	WYCO Development L.L.C.
KinderHawk	=	KinderHawk Field Services LLC			

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

Common Industry and Other Terms

/d	=	per day	LIBOR	=	London Interbank Offered Rate
AFUDC	=	allowance for funds used during construction	LLC	=	limited liability company
BBtu	=	billion British Thermal Units	LNG	=	liquefied natural gas
Bcf	=	billion cubic feet	MBbl	=	thousand barrels
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act	MDth	=	thousand dekatherms
			MLP	=	master limited partnership
CO_2	=	carbon dioxide or our CO_2 business segment	MMBbl	=	million barrels
CPUC	=	California Public Utilities Commission	MMcf	=	million cubic feet
DCF	=	distributable cash flow	NEB	=	National Energy Board
DD&A	=	depreciation, depletion and amortization	NGL	=	natural gas liquids
DGCL	=	General Corporation Law of the state of Delaware	NYMEX	=	New York Mercantile Exchange
Dth	=	dekatherms	NYSE	=	New York Stock Exchange
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	OTC	=	over-the-counter
			PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
EPA	=				

		United States Environmental Protection Agency			
FASB	=	Financial Accounting Standards Board	SEC	=	United States Securities and Exchange Commission
FERC	=	Federal Energy Regulatory Commission			
FTC	=	Federal Trade Commission	TBtu	=	trillion British Thermal Units
GAAP	=	United States Generally Accepted Accounting Principles	WTI	=	West Texas Intermediate

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, service debt or 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 our forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- the extent of volatility in prices for and resulting changes in demand for NGL, refined petroleum products, oil, CO_2, natural gas, electricity, coal, steel and other bulk materials and chemicals and certain agricultural products in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates required by the FERC, the CPUC, Canada’s NEB or another regulatory agency;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;
- our ability to safely operate and maintain our existing assets and to access or construct new pipeline, gas processing and NGL fractionation capacity;
- our ability to attract and retain key management and operations personnel;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, natural gas processing plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production (and the NGL content of natural gas production) from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the shale plays in North Dakota, Oklahoma, Ohio, Pennsylvania and Texas, and the U.S. Rocky Mountains and the Alberta, Canada oil sands;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may increase our compliance costs, restrict our ability to provide or reduce demand for our services, or otherwise adversely affect our business;
- interruptions of operations at our facilities due to natural disasters, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;
- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves that we may experience;

- regulatory, environmental, political, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts;
- the ability of our customers and other counterparties to perform under their contracts with us;

- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;

- changes in tax law;

- our ability to access external sources of financing in sufficient amounts and on acceptable terms to the extent needed to fund acquisitions of operating businesses and assets and expansions of our facilities;

- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;

- our ability to obtain insurance coverage without significant levels of self-retention of risk;

- acts of nature, sabotage, terrorism (including cyber attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;

- possible changes in our and our subsidiaries credit ratings;

- conditions in the capital and credit markets, inflation and fluctuations in interest rates;

- political and economic instability of the oil producing nations of the world;

- national, international, regional and local economic, competitive and regulatory conditions and developments;

- our ability to achieve cost savings and revenue growth;

- foreign exchange fluctuations;

- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells; and

- unfavorable results of litigation and the outcome of contingencies referred to in Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

See Item 1A “Risk Factors” for a more detailed description of these and other factors that may affect our forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in Item 1A “Risk Factors.” The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, and described below under Items 1 and 2, “Business and Properties–—(a) General Development of Business—Recent Developments—2016 Outlook”, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. Business and Properties.

We are the largest energy infrastructure company in North America. We own an interest in or operate approximately 84,000 miles of pipelines and approximately 180 terminals (includes 15 terminals acquired in our February 2016 BP Products North America Inc. (BP) transaction). For more information about the acquisition, see Note 3 “Acquisitions and Divestitures” to our consolidated financial statements. 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. Our common stock trades on the NYSE under the symbol “KMI.”

(a) General Development of Business

Organizational Structure

On November 26, 2014, we completed our acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of Kinder Morgan Energy Partners, L.P. and El Paso Pipeline Partners, L.P. and all of the outstanding shares of Kinder Morgan Management, LLC that we did not already own. The transactions, valued at approximately $77 billion, are referred to collectively as the “Merger Transactions.”

As we controlled each of KMP, KMR and EPB before and continued to control each of them after the Merger Transactions, the changes in our ownership interest in each of KMP, KMR and EPB were accounted for as an equity transaction and no gain or loss was recognized in our consolidated statements of income related to the Merger Transactions. After closing the KMR Merger Transaction, KMR was merged with and into KMI.

Additionally, on January 1, 2015, EPB and its subsidiary, EPPOC merged with and into KMP. As a result of such merger, all of the subsidiaries of EPB and EPPOC became wholly owned subsidiaries of KMP. References to EPB refer to EPB for periods prior to its merger into KMP.

Prior to the Merger Transactions, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP were eliminated.

Historically, most of our operating assets were owned and most of our investments were conducted by KMP and EPB.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to the Merger Transactions are reflected within “Noncontrolling interests” in our accompanying consolidated statements of stockholders’ equity. The earnings recorded by KMP, EPB and KMR that were attributed to the units and shares, respectively, held by the public prior to the Merger Transactions are reported as “Net income attributable to noncontrolling interests” in our accompanying consolidated statements of income.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000.

Recent Developments

The following is a brief listing of significant developments and updates related to our major projects. Additional information regarding most of these items may be found elsewhere in this report. “Capital Scope” is estimated for our share of the described project which may include portions not yet completed.

Asset or project	Description	Activity	Approx. Capital Scope
Placed in service or acquisitions			
Hiland Partners	Assets consist of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily serving production from the Bakken Formation in North Dakota and Montana, including the Double H crude oil pipeline.	Acquired February 2015.	$3.0 billion

Asset or project	Description	Activity	Approx. Capital Scope
TGP Broad Run Flexibility and Broad Run Expansion	Modification to existing pipelines under two separate projects to create 790,000 Dth/d of north-to-south gas transportation capacity from a receipt point in West Virginia to delivery points in Mississippi and Louisiana. Subscribed under long-term firm transportation contracts.	TGP Broad Run Flexibility facilities were placed in service November 2015 to allow for deliveries of 590,000 Dth/d; In-service of the remaining 200,000 Dth/d as of June 1, 2018.	$800 million
ELC Acquisition	Acquired Shell's 49 percent equity interest in the ELC joint venture to develop liquefaction facilities at Elba Island, Georgia.	Acquired July 2015.	$510 million
TGP South System Flexibility	Expansion project that provides more than 900 miles of north-to-south transportation capacity of 500,000 Dth/d on our TGP system from Tennessee to South Texas and expands our transportation service to Mexico. Subscribed under long-term firm transportation contracts.	Initial volume placed into service January 2015. The next capacity increment was placed in service December 2015, with the remainder expected in December 2016.	$216 million
NGPL Acquisition	Acquired equity interest from Myria Holdings, Inc. increasing ownership in NGPL from 20 percent to 50 percent.	Acquired December 2015.	$136 million
Cow Canyon development	An expansion project that will increase CO_2 production in the Cow Canyon area of the McElmo Dome source field by 200 MMcf/d.	Majority placed in service in 2015.	$309 million
Edmonton Rail Terminal	Expansion increases capacity to over 210,000 bpd at the joint venture crude rail terminal in Edmonton. The facility, supported by long-term customer contracts, will be connected via pipeline to the Trans Mountain pipeline and be capable of sourcing all crude streams handled by us for delivery by rail to North American markets and refineries.	Placed in service second quarter 2015.	CAD$270 million
Royal Vopak U.S. Terminal acquisition	Purchase of three U.S. terminals and one undeveloped site.	Acquisition closed in February 2015.	$158 million
Galena Park Tank Project and Pasadena Barge Dock	Construction of nine storage tanks with total shell capacity of 1.2 million barrels and a new barge dock at Pasadena, supported by long-term customer contracts.	Final three tanks were placed in service first quarter 2015; barge dock placed in service December 2015.	$138 million
KM Condensate Processing Facility	Project includes building two separate units to split condensate into various components and construct storage tanks totaling almost 2 million barrels to support the processing operation, supported by long-term customer contracts.	Placed in service March 2015 (phase 1) and July 2015 (phase 2).	$445 million

Other Announcements

Natural Gas Pipelines			
TGP Northeast Energy Direct-Market Path	Development of a 188-mile market path that will extend from Wright, New York to Dracut, Massachusetts.	Expected in service November 2018.	$3.1 billion
ELC and SLNG expansion	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Ga., with a total capacity of 2.5 million tonnes per year of LNG, equivalent to 350 MMcf/d of natural gas. Supported by a 20-year contract with Shell.	First of 10 liquefaction units expected in service first quarter 2018 with the remainder by the end of 2018.	$2.0 billion
EPNG upstream Sierrita Gas Pipeline LLC	Expansion projects to provide 550,000 Dth/d contracted, firm natural gas transport capacity with a first phase of system improvements to deliver volumes to the Sierrita pipeline and the second phase for incremental deliveries of natural gas to Arizona and California.	Phase one placed in service October 2014 ($2 million), phase two expected fully in service July 2020 ($389 million).	$391 million
Elba Express and SNG expansion	Expansion project that provides 854,000 Dth/d incremental contracted, firm natural gas transportation service supporting the needs of customers in Georgia, South Carolina and northern Florida, and also serving ELC.	Expected in service late third quarter or early fourth quarter of 2016 (first phase) and 2017.	$306 million
TGP Southwest Louisiana Supply (formerly Cameron LNG)	Project provides 900,000 Dth/d of long-term capacity to the future Cameron LNG export complex at Hackberry, Louisiana. Subscribed under long-term firm transportation contracts.	Expected in service February 2018.	$178 million

Asset or project	Description	Activity	Approx. Capital Scope
Texas Intrastate Crossover Expansion	Expansion project creating capacity from the Katy Hub, the company's Houston Central processing plant, and other third party receipt points to serve the Texas Intrastate's transportation commitments of 250,000 Dth/day to the Cheniere Corpus Christi LNG export facility and 527,000 Dth/day to the CFE at delivery points in South Texas.	Expected in-service September 2016 for the CFE commitment and January 2019 for the Cheniere commitment.	$164 million
Texas Intrastate SK Freeport LNG	Entered into a 20-year firm transportation services agreement with SK E&S LNG, LLC in December 2014 to provide more than 320,000 Dth/d of firm natural gas transportation services.	Expected in-service January 2019	$161 million
TGP Susquehanna West	Expansion project that provides 145,000 Dth/d incremental natural gas transportation capacity, serving the northeast Marcellus to points of liquidity. Subscribed under long-term firm transportation contracts.	Expected in service November 2017.	$156 million
KMLP Magnolia LNG Liquefaction Transport	Upgrades to existing pipeline system to provide 700,000 Dth/d capacity to serve Magnolia LNG in the Lake Charles, La., area. Subscribed under long-term firm transportation contracts.	Expected in-service fourth quarter 2018	$156 million
KMLP Cheniere Sabine Pass LNG	Reconfiguration to flow northeast to southeast to deliver 600 MDth/d to the Cheniere Sabine Pass Liquefaction Terminal in Cameron Parish, LA. Subscribed under long-term firm transportation contracts.	Expected in-service fourth quarter 2019	$146 million
TGP Orion (formerly Marcellus to Milford)	An expansion project to provide additional firm capacity from the Marcellus supply basin to TGP's interconnection with Columbia Gas Transmission in Pike County, Pennsylvania. The capacity of this expansion will be at least 135,000 Dth/d. Subscribed under long-term firm transportation contracts.	Expected in service June 2018.	$142 million
TGP Lone Star	Two Greenfield compressor stations to provide supply to the Corpus Christi LNG liquefaction project, for a capacity of 300,000 Dth/d. Subscribed under long-term firm transportation contracts.	Expected in-service July 2019.	$134 million
TGP Triad Expansion	Expansion project that provides 180,000 Dth/d of long-term capacity for Invernergy's Lakawanna Energy Center to serve a planned new area power plant. Subscribed under long-term firm transportation contracts.	Expected in service November 2017.	$87 million
CO_2			
Cortez Pipeline expansion	Project will increase capacity from 1.35 Bcf/d to 1.5 Bcf/d on this existing pipeline. This pipeline will transport CO_2 from southwestern Colorado to eastern New Mexico and west Texas for use in	Expected full in service second quarter 2016.	$214 million

	enhanced oil recovery projects.		
Terminals			
KM General Dynamics' NASSCO Tankers	Purchase of five medium-range Jones Act tankers constructed by General Dynamics' NASSCO Shipyard in San Diego. All of the tankers will be 50,000-deadweight-ton, LNG conversion-ready product carriers, with a capacity of 330,000 barrels and contracted for an average of 5 years.	First tanker delivery took place in December 2015. Delivery of remaining four tankers expected between early 2016 and mid-2017.	$782 million
KM Philly Tankers	Further expansion of growing fleet of Jones Act product tankers with the purchase of four, new 50,000-deadweight-ton. The Tier II tankers will be constructed by Philly Shipyard. (two under contract and two remaining to be contracted). Each LNG conversion-ready tanker will have a capacity of 337,000 barrels.	Definitive agreement executed. Delivery of tankers expected between November 2016 and November 2017.	$633 million
KM and BP Joint Venture	Acquire 15 refined products terminals and associated infrastructure. KM and BP have formed a joint venture to own 14 of the acquired assets. One terminal will be owned solely by KM.	Closed on February 1, 2016	$350 million
KM Export Terminal	Brownfield expansion along Houston Ship Channel will add 12 storage tanks with 1.5 million barrels of liquids storage capacity, one ship dock, one barge dock and cross-channel pipelines to connect with the KM Galena Park terminal. Supported by a long-term contract with a major ship channel refiner.	Expected in service first quarter 2017.	$220 million

Asset or project	Description	Activity	Approx. Capital Scope
KM Base Line Terminal development	Announced a 50-50 joint venture with Keyera Corp. to build a new 4.8 million barrels of crude oil storage facility in Edmonton, Alberta. Subscribed under long-term contracts.	Planning-permitting activities continue.	CAD$372 million
Products Pipelines			
Palmetto Pipeline	Construction of a new 360-mile pipeline, underpinned by long-term customer contracts, to move gasoline, diesel and ethanol from Louisiana, Mississippi and South Carolina to points in South Carolina, Georgia and Florida.	Expected in service December 2017.	$1 billion
Utopia East Pipeline	Building of new 240 mile pipeline, supported by a long-term customer contract, to transport ethane and ethane-propane mixtures from the prolific Utica Shale, with an initial design capacity of 50,000 bpd, expandable to more than 75,000 bpd.	Expected in service January 2018.	$517 million
Kinder Morgan Canada			
Trans Mountain Expansion Project	An increase of capacity on our Trans Mountain pipeline system from approximately 300,000 to 890,000 barrels per day, underpinned by long-term take-or-pay contracts.	Currently engaged in final approval process with the NEB and federal government, expected in service third quarter 2019.	$5.4 billion

Financings

On January 26, 2016, we closed on a three-year, unsecured $1 billion term loan and a $1 billion expansion of our unsecured revolving credit facility, increasing the capacity of that facility from $4 billion to $5 billion. Proceeds from the term loan were used to repay existing borrowings and for general corporate purposes. Pricing and the covenant package of both facilities are consistent with our existing revolving credit facility.

Current Commodity Price Environment

Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” as well as Note 4 “Impairments and Disposals” and Note 8 “Goodwill” to our consolidated financial statements, discuss the impacts of the current commodity price environment on the energy industry, including our customers and us. Refer to the developments addressed in these sections, including the resulting non-cash impairment charges related to goodwill, certain long-lived assets and equity method investments. For a more general discussion of these related risk factors, refer to Item 1A. “Risk Factors.”

Dividend Announcement

Refer to Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources” for a discussion regarding the reduction in our dividend announced in December 2015 to an expected $0.50 per share on an annualized basis.

2016 Outlook

We expect to declare dividends of $0.50 per share for 2016, generate approximately $4.9 billion of distributable cash flow available to equity and approximately $4.7 billion of distributable cash flow available to common shareholders (i.e. after payment of preferred dividends) and generate approximately $3.6 billion of cash flow in excess of our dividend. These expectations assume an average 2016 WTI crude oil price of $38 per barrel, an average 2016 Henry Hub natural gas price of $2.50 per MMBtu and interest rates consistent with the current forward curve at the time that our 2016 budget was prepared.

The overwhelming majority of cash we generate is fee-based and therefore is not directly exposed to commodity prices. The primary area where we have direct commodity price sensitivity is in our CO_2 segment, where we hedge the majority of the next 12 months of oil production to minimize this sensitivity. For 2016, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our distributable cash flow by approximately $6.5 million and each $0.10 per MMBtu change in the average price of natural gas impacts distributable cash flow by approximately $0.6 million, and every 1% change in the ratio of the weighted-average NGL price per barrel to the WTI crude oil price per barrel impacts distributable cash flow by approximately $2.0 million. These sensitivities compare to total anticipated segment earnings before DD&A in 2016 of approximately $8 billion (adding back our share of joint venture DD&A).

We expect that a full-year of contributions from our 2015 acquisitions and expansions along with partial-year contributions from our anticipated 2016 expansion investments, as described above under "—Recent Developments", will generate incremental earnings and cash flow from our assets in 2016 and beyond. Generally, our base cash flows (that is, cash flows not attributable to acquisitions or expansions) are relatively stable from year to year and are largely supported by multi-year, fee-based customer arrangements.

In addition, our expectations for 2016 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and because of these uncertainties, it is advisable to not put undue reliance on any forward-looking statement. Please read our Item 1A "Risk Factors" below for more information. Furthermore, we plan to provide updates to our 2016 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

(b) Financial Information about Segments

For financial information on our six reportable business segments, see Note 16 "Reportable Segments" to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

Our business strategy is to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of growing markets within North America;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leverage economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow; and
- maintain a strong balance sheet and return value to our stockholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A. "Risk Factors" below, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

We regularly consider and enter into discussions regarding potential acquisitions and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions, and approval of our board of directors, if applicable. While there are currently no unannounced purchase agreements for the acquisition of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Business Segments

We operate the following reportable business segments. These segments and their principal sources of revenues are as follows:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;
- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil

fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;

- Products Pipelines—the ownership and operation of refined petroleum products and crude oil and condensate pipelines that deliver refined petroleum products (gasoline, diesel fuel and jet fuel), NGL, crude oil, condensate and bio-fuels to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;
- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport; and
- Other—primarily other miscellaneous assets and liabilities including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with legacy trading activities; and (iii) other miscellaneous legacy assets and liabilities.

Natural Gas Pipelines

Our Natural Gas Pipelines segment includes interstate and intrastate pipelines and our LNG terminals, and includes both FERC regulated and non-FERC regulated assets.

Our primary businesses in this segment consist of natural gas sales, transportation, storage, gathering, processing and treating, and the terminaling of LNG. Within this segment, are: (i) approximately 52,000 miles of natural gas pipelines and (ii) our equity interests in entities that have approximately 19,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Louisiana, Texas, the Midwest, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG storage and regasification terminals also serve natural gas supply areas in the southeast. The following tables summarize our significant Natural Gas Pipelines segment assets, as of December 31, 2015. The Design Capacity represents either transmission, gathering or liquefaction capacity depending on the nature of the asset.

	Ownership Interest %	Miles of Pipeline	Design (Bcf/d) [Storage (Bcf)] Capacity	Supply and Market Region
Natural Gas Pipelines				
TGP	100	11,800	9.74 [99]	South Texas and Gulf of Mexico to northeast and southeast U.S.; Haynesville, Marcellus, Utica, and Eagle Ford shale formations
EPNG/Mojave pipeline system	100	10,700	5.65 [44]	Northern New Mexico, Texas, Oklahoma, to California, connects to San Juan, Permian, and Anadarko basins
NGPL	50	9,100	6.20 [288]	Chicago and other Midwest markets and all central U.S. supply basins
SNG	100	6,900	3.90 [68]	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee; basins in Texas, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus)	50	5,300	3.60	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
CIG	100	4,300	5.15 [43]	Colorado and Wyoming; Rocky Mountains and the Anadarko Basin
WIC	100	850	3.88	Wyoming, Colorado, and Utah; Overthrust, Piceance, Uinta, Powder River and Green River Basins
Ruby pipeline	50	680	1.53	Wyoming to Oregon; Rocky Mountain basins
MEP	50	510	1.80	

				Oklahoma and north Texas supply basins to interconnects with deliveries to interconnects with Transco, Columbia Gulf and various other pipelines
CPG	100	410	1.20	Colorado and Kansas, natural gas basins in the Central Rocky Mountain area
TransColorado Gas	100	310	0.98	Colorado and New Mexico; connects to San Juan, Paradox and Piceance basins
WYCO	50	224	1.20 [7]	Northeast Colorado; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCo’s pipeline system

	Ownership Interest %	Miles of Pipeline	Design (Bcf/d) [Storage (Bcf)] Capacity	Supply and Market Region
Elba Express	100	200	0.95	Georgia; connects to SNG (Georgia), Transco (Georgia/South Carolina), SLNG (Georgia) and CGT (Georgia).
FEP	50	185	2.00	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission, and ANR Pipeline Company
KMLP	100	135	2.20	sources gas from Cheniere Sabine Pass LNG terminal to interconnects with Columbia Gulf, ANR and various other pipelines
Sierrita Gas Pipeline LLC	35	61	0.20	near Tucson, Arizona, to the U.S.-Mexico border near Sasabe, Arizona; connects to EPNG and via a new international border crossing with a new natural gas pipeline in Mexico
Young Gas Storage	48	16	[6]	Morgan County, Colorado, capacity is committed to CIG and Colorado Springs Utilities.
Keystone Gas Storage	100	12	[6]	located in the Permian Basin and near the WAHA natural gas trading hub in West Texas.
Gulf LNG Holdings	50	5	[6.6]	near Pascagoula, Mississippi; connects to four interstate pipelines and natural gas processing plant.
Bear Creek Storage	100	—	[59]	located in Louisiana; provides storage capacity to SNG and TGP.
SLNG	100	—	[11.5]	Georgia; connects to Elba Express, SNG and CGT
ELC	100	—	0.35	Georgia; not in service until 2018
Midstream assets				
KM Texas and Tejas pipelines	100	5,600	6.20 [124]	Texas Gulf Coast.
Mier-Monterrey pipeline	100	87	0.65	Starr County, Texas to Monterrey, Mexico; connects to Pemex NG Transportation system and a 1,000-megawatt power plant
KM North Texas pipeline	100	82	0.33	interconnect from NGPL; connects to 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Oklahoma				
Southern Dome	73	—	0.03	propane refrigeration plant in the southern portion of Oklahoma county
Oklahoma System	100	3,600	0.38	Hunton Dewatering, Woodford Shale, and Mississippi Lime
South Texas				
Webb/Duval gas gathering system	63	145	0.15	South Texas
South Texas System	100	1,300	1.88	Eagle Ford shale formation, Woodbine and Eaglebine (Texas)
EagleHawk	25	860	1.20	South Texas, Eagle Ford shale formation
KM Altamont	100	1,200	0.08	Utah, Uinta Basin

Red Cedar	49	740	0.70	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union	37	310	1.25	Powder River Basin (Wyoming)
Bighorn	51	290	0.60	Powder River Basin (Wyoming)
KinderHawk	100	500	2.00	Northwest Louisiana, Haynesville and Bossier shale formations
North Texas	100	400	0.14	North Barnett Shale Combo
Endeavor	40	100	0.12	East Texas, Cotton Valley Sands and Haynesville/ Bossier Shale horizontal well developments
Camino Real - Gas	100	70	0.15	South Texas, Eagle Ford shale formation
KM Treating	100	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas

13

	Ownership Interest %	Miles of Pipeline	Design (Bcf/d) [Storage (Bcf)] Capacity	Supply and Market Region
Hiland				
Williston - Gas	100	2,000	0.31	Bakken shale formation (North Dakota)
Midcontinent	100	690	0.23	Woodford Shale, Anadarko Basin and Arkoma Basin
			(MBbl/d)	
Liquids				
Liberty Pipeline	50	87	170	Houston Central complex to the Texas Gulf Coast
Liquids Assets	100	345	115	Houston Central complex to the Texas Gulf Coast
Camino Real - Oil	100	68	110	South Texas, Eagle Ford shale formation
Williston - Oil	100	1,400	266	Bakken shale formation (North Dakota)

Competition

The market for supply of natural gas is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve the growing demand for natural gas in each of the markets served by the pipelines in our Natural Gas Pipelines business segment. Our operations compete with interstate and intrastate pipelines, and their shippers, for connections to new markets and supplies and for transportation, processing and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service and flexibility and reliability of service. From time to time, other projects are proposed that would compete with us. We do not know whether or when any such projects would be built, or the extent of their impact on our operations or profitability.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including electricity, coal, propane and fuel oils. Several factors influence the demand for natural gas, including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the ability to convert to alternative fuels and weather.

CO_2

Our CO_2 business segment produces, transports, and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 supply, transportation and technical expertise to our customers. We also hold ownership interests in several oil-producing fields and own a crude oil pipeline, all located in the Permian Basin region of West Texas.

Oil and Gas Producing Activities

Oil Producing Interests

Our ownership interests in oil-producing fields located in the Permian Basin of West Texas, include the following:

	Working Interest %	KM Gross Developed Acres
SACROC	97	49,156
Yates	50	9,576
Goldsmith Landreth San Andres(a)	99	6,166
Katz Strawn	99	7,194
Sharon Ridge	14	2,619
Tall Cotton (ROZ)	100	461
H.T. Boyd(b)	21	n/a
MidCross	13	320
Reinecke(c)	—	80

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(a) Acquired June 1, 2013
(b) Net profits interest
(c) Working interest less than 1 percent.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we owned interests as of December 31, 2015. The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. When used with respect to acres or wells, "gross" refers to the total acres or wells in which we have a working interest, and "net" refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells(a)		Service Wells(b)		Drilling Wells(c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,199	1,415	1,157	910	2	2
Natural Gas	5	2	—	—	—	—
Total Wells	2,204	1,417	1,157	910	2	2

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(a) Includes active wells and wells temporarily shut-in. As of December 31, 2015, we did not operate any productive wells with multiple completions.
(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of salt water into an underground formation; and an injection well is a well drilled in a known oil field in order to inject liquids and/or gases that enhance recovery.
(c) Consists of development wells in the process of being drilled as of December 31, 2015. A development well is a well drilled in an already discovered oil field.

The following table reflects our net productive wells that were completed in each of the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Productive			
Development	130	83	51
Exploratory	31	26	4
Total Productive	161	109	55
Dry Exploratory	—	1	—

Total Wells	161	110	55

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Note: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. A development well is a well drilled in an already discovered oil field.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2015:

	Gross	Net
Developed Acres	75,572	72,382
Undeveloped Acres	17,142	14,952
Total	92,714	87,334

Note: As of December 31, 2015, we have no material amount of acreage expiring in the next three years.

See "Supplemental Information on Oil and Gas Activities (Unaudited)" for additional information with respect to operating statistics and supplemental information on our oil and gas producing activities.

Gas and Gasoline Plant Interests

Operated gas plants in the Permian Basin of West Texas:

	Ownership Interest %	Source
Snyder gasoline plant(a)	22	The SACROC unit and neighboring CO_2 projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51	Snyder gasoline plant
North Snyder plant	100	Snyder gasoline plant

(a) This is a working interest, in addition, we have a 28% net profits interest. The average net to us does not include the value associated with the net profits interest.

Sales and Transportation Activities

CO_2 Segment Storage and Sales

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. Our ownership of CO_2 resources as of December 31, 2015 includes:

	Ownership Interest %	Recoverable CO_2 (Bcf)	Compression Capacity (Bcf/d)	Location
Recoverable CO_2				
McElmo Dome unit(a)(b)	45	4,758	1.5	Colorado
Doe Canyon Deep unit(a)	87	569	0.2	Colorado
Bravo Dome unit	11	616	0.3	New Mexico

(a) We also operate.
(b) Recoverable CO_2 estimate from currently approved projects only.

CO_2 Segment Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. The tariffs charged on the Wink pipeline system are regulated by both the FERC and the Texas Railroad Commission and the Pecos Carbon Dioxide Pipeline's tariffs are regulated by the Texas Railroad Commission. The tariff charged on the Cortez pipeline is based on a consent decree and the tariffs charged by our other CO_2 pipelines are not regulated.

Our ownership of CO_2 and crude oil pipelines as of December 31, 2015 includes:

	Ownership Interest %	Miles of Pipeline	Transport Capacity(Bcf/d)	Supply and Market Region
CO_2 pipelines				
Cortez pipeline	50	565	1.3	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	100	324	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline(a)	13	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline	98	163	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO_2 pipeline	100	113	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO_2 pipeline	100	91	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline(b)	95	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
Goldsmith Landreth	99	3	0.2	Goldsmith Landreth San Andres field in the Permian Basin of West Texas
			(Bbls/d)	
Crude oil pipeline				
Wink pipeline	100	454	145,000	West Texas to Western Refining's refinery in El Paso, Texas

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(a) We do not operate Bravo pipeline.
(b) Acquired Chevron's 26.01% partnership interest in December 2015.

Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources, and Oxy U.S.A., Inc., which controls waste CO_2 extracted from natural gas production in the Val Verde Basin of West Texas. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Terminals

Our Terminals segment includes the operations of our petroleum, chemical, ethanol and other liquids terminal facilities (other than those included in the Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities, including all transload, engineering, conveying and other in-plant services. Our terminals are located throughout the U.S. and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide expansion opportunities. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, we have Jones Act qualified product tankers that provide marine transportation of crude oil, condensate and refined products in the U.S. The following summarizes our Terminals segment assets, as of December 31, 2015:

	Number	Capacity (MMBbl)
Liquids terminals(a)	52	87.6
Bulk terminals	59	n/a
Jones Act qualified tankers	8	2.6

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(a) Includes 10 terminals acquired in February 2016.

Competition

We are one of the largest independent operators of liquids terminals in the U.S, based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical and pipeline companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminal services. In some locations, competitors are smaller, independent operators with lower cost structures. Our Jones Act qualified product tankers compete with other Jones Act qualified vessel fleets.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products, crude oil and condensate, and NGL pipelines and associated terminals, Southeast terminals, and our transmix processing facilities. The following summarizes our significant Products Pipelines segment assets we own and operate as of December 31, 2015:

	Ownership Interest %	Miles of Pipeline	Number of Terminals (a)(c) or locations	Terminal Capacity(MMBbl)	Supply and Market Region
Plantation pipeline	51	3,182			Louisiana to Washington D.C.
West Coast Products Pipelines(b)					
Pacific (SFPP)	100	2,823	13	15.3	six western states
Calnev	100	570	2	2.1	Colton, CA to Las Vegas, NV; Mojave region
West Coast Terminals	100	43	7	10.1	Seattle, Portland, San Francisco and Los Angeles areas
Cochin pipeline	100	1,877	5	1.1	three provinces in Canada and seven states in the U.S.
KM Crude & Condensate pipeline	100	252	5	2.6	Eagle Ford shale field in South Texas (Dewitt County) to the Houston ship channel refining complex
Double H Pipeline	100	511			Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Central Florida pipeline	100	206	3	3.1	Tampa to Orlando
Double Eagle pipeline	50	194	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
Parkway	50	140			interconnect at Collins with Plantation and Plantation markets
Cypress pipeline	50	104			Mont Belvieu, Texas to Lake Charles, Louisiana
Southeast Terminals	100		32	10.8	from Mississippi through Virginia, including Tennessee
Transmix Operations	100		6	1.5	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; St. Louis, Missouri; and Greensboro, North Carolina

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(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

(b) Our West Coast Products Pipelines assets include interstate common carrier pipelines rate-regulated by the FERC, intrastate pipelines in the state of California rate-regulated by the CPUC, and certain non rate-regulated operations and terminal facilities.

(c) Includes 5 terminals acquired in February 2016.

Competition

Our Products Pipelines' pipeline operations compete against proprietary pipelines owned and operated by major oil companies, other independent products pipelines, trucking and marine transportation firms (for short-haul movements of products) and railcars. Our Products Pipelines' terminal operations compete with proprietary terminals owned and operated by major oil companies and other independent terminal operators, and our transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Kinder Morgan Canada

Our Kinder Morgan Canada business segment includes our 100% owned and operated Trans Mountain pipeline system and a 25-mile Jet Fuel pipeline system.

Trans Mountain Pipeline System

The Trans Mountain pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum products to destinations in the interior and on the west coast of British Columbia. The Trans Mountain pipeline is 713 miles in length. We also own and operate a connecting pipeline that delivers crude oil to refineries in the state of Washington. The capacity of the line at Edmonton ranges from 300 MBbl/d when heavy crude oil represents 20% of the total throughput (which is a historically normal heavy crude oil percentage), to 400 MBbl/d with no heavy crude oil.

Jet Fuel Pipeline System

We also own and operate the approximate 25-mile aviation fuel pipeline that serves the Vancouver International Airport, located in Vancouver, British Columbia, Canada. The turbine fuel pipeline is referred to in this report as the Jet Fuel pipeline system. In addition to its receiving and storage facilities located at the Westridge Marine terminal, located in Port Metro Vancouver, the Jet Fuel pipeline system's operations include a terminal at the Vancouver airport that consists of five jet fuel storage tanks with an overall capacity of 15 MBbl.

Competition

Trans Mountain is one of several pipeline alternatives for western Canadian crude oil and refined petroleum production, and it competes against other pipeline providers; however, it is the sole pipeline carrying crude oil and refined petroleum products from Alberta to the west coast. Furthermore, as demonstrated by our previously announced expansion proposal, discussed above in "—(a) General Development of Business—Recent Developments—Kinder Morgan Canada," we believe that the Trans Mountain pipeline facilities provide us the opportunity to execute on capacity expansions to the west coast as the market for offshore exports continues to develop.

In December 2013, the British Columbia Ministry of Environment granted approval for a new, airport fuel consortium owned, jet fuel terminal to be located near the Vancouver International Airport. The impact of this facility on our existing Jet Fuel pipeline system is uncertain at this time.

Other

During 2015, our other segment activity primarily includes other miscellaneous assets and liabilities including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with legacy trading activities; and (iii) other miscellaneous legacy assets and liabilities.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2015, 2014 and 2013, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas Intrastate Natural Gas Pipeline operations (includes the operations of Kinder Morgan Tejas Pipeline LLC, Kinder Morgan Border Pipeline LLC, Kinder Morgan Texas Pipeline LLC, Kinder Morgan North Texas Pipeline LLC and the Mier-Monterrey Mexico pipeline system) buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2 business segments in 2015, 2014 and 2013 accounted for 20%, 25% and 28%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations

Some of our U.S. refined petroleum products and crude oil gathering and transmission pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be “just and reasonable” and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

Common Carrier Pipeline Rate Regulation - Canadian Operations

The Canadian portion of our crude oil and refined petroleum products pipeline systems is under the regulatory jurisdiction of the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service. Our subsidiary Trans Mountain Pipeline, L.P. is the sole owner of our Trans Mountain crude oil and refined petroleum products pipeline system.

The toll charged for the portion of Trans Mountain's pipeline system located in the U.S. falls under the jurisdiction of the FERC. For further information, see "—Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations" above.

Interstate Natural Gas Transportation and Storage Regulation

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates offered within the range of tariff maximums and minimums, the pipeline is permitted to charge negotiated rates where the pipeline and shippers want rate certainty, irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. Negotiated rates provide certainty to the pipeline and the shipper of agreed upon rates during the term of the transportation agreement, regardless of changes to the posted tariff rates. There are a variety of rates that different shippers may pay, but while the rates may vary by shipper and circumstance, pipelines must generally use the form of service agreement that is contained within their FERC approved tariff. Any deviation from the pro forma service agreements must be filed with the FERC and only certain types of deviations are acceptable to the FERC.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980's, the FERC initiated a number of regulatory changes intended to ensure that interstate natural gas pipelines operated on a not unduly discriminatory basis and to create a more competitive and transparent environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) which required open-access, nondiscriminatory transportation of natural gas;
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Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;

- Order Nos. 587, et seq., Order No. 809 (1996-2015) which adopt regulations to standardize the business practices and communication methodologies of interstate natural gas pipelines to create a more integrated and efficient pipeline grid and wherein the Commission has incorporated by reference in its regulations standards for interstate natural gas pipeline business practices and electronic communications that were developed and adopted by the North American Energy Standards Board (NAESB). Interstate natural gas pipelines are required to incorporate by reference or verbatim in their respective tariffs the applicable version of the NAESB standards;

- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies. Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for the natural gas commodity, transportation and storage);
- Order No. 637 (2000) which revised, among other things, FERC regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties in order to improve the competitiveness and efficiency of the interstate pipeline grid; and
- Order No. 717 (2008) amending the Standards of Conduct for Transmission Providers (the Standards of Conduct or the Standards) to make them clearer and to refocus the marketing affiliate rules on the areas where there is the greatest potential for abuse. The FERC standards of conduct address and clarify multiple issues with respect to the actions and operations of interstate natural gas pipelines and public utilities using a functional approach to ensure that natural gas transmission is provided on a nondiscriminatory basis, including (i) the definition of transmission function and transmission function employees; (ii) the definition of marketing function and marketing function employees; (iii) the definition of transmission function information and non-disclosure requirements regarding non-public information; (iv) independent functioning and no conduit requirements; (v) transparency requirements; and (vi) the interaction of FERC standards with the NAESB business practice standards. The Standards of Conduct rules also require that a transmission provider provide annual training on the standards of conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information.

In addition to regulatory changes initiated by the FERC, the U.S. Congress passed the Energy Policy Act of 2005. Among other things, the Energy Policy Act amended the Natural Gas Act to: (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

CPUC Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the CPUC under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the Pacific operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before the CPUC, as is more fully described in Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

Railroad Commission of Texas (RCT) Rate Regulation

The intrastate operations of our crude oil and liquids pipelines and natural gas pipelines and storage facilities in Texas are subject to regulation with respect to such intrastate transportation by the RCT. The RCT has the authority to regulate our rates, though it generally has not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Mexico - Energy Regulatory Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulating Commission (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2026.

This permit establishes certain restrictive conditions, including without limitations (i) compliance with the general conditions for the provision of natural gas transportation service; (ii) compliance with certain safety measures, contingency plans, maintenance plans and the official Mexican standards regarding safety; (iii) compliance with the technical and economic specifications of the natural gas transportation system authorized by the Commission; (iv) compliance with certain technical studies established by the Commission; and (v) compliance with a minimum contributed capital not entitled to withdrawal of at least the equivalent of 10% of the investment proposed in the project.

Safety Regulation

We are also subject to safety regulations imposed by PHMSA, including those requiring us to develop and maintain pipeline Integrity Management programs to comprehensively evaluate areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas, or HCAs, where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with pipeline Integrity Management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional integrity threats and changes to the amount of pipe determined to be located in HCAs can have a significant impact on costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA regulations. These tests could result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which was signed into law in 2012, increased penalties for violations of safety laws and rules and may result in the imposition of more stringent regulations in the next few years. In 2012, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine maximum pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the Advisory Bulletin requirements, could significantly increase our costs. Additionally, failure to locate such records to verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. There can be no assurance as to the amount or timing of future expenditures for pipeline Integrity Management regulation, and actual expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, 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.

We are also subject to the requirements of the Occupational Safety and Health Administration (OSHA) and other federal and state agencies that address employee health and safety. In general, we believe current expenditures are addressing the OSHA requirements and protecting the health and safety of our employees. Based on new regulatory developments, we may increase expenditures in the future to comply with higher industry and regulatory safety standards. However, such increases in our expenditures, and the extent to which they might be offset, cannot be estimated at this time.

State and Local Regulation

Our activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and human health and safety.

Marine Operations

The operation of tankers and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and manned by U.S. citizens. As a result, we monitor the foreign ownership of our common stock and under certain circumstances, consistent with our certificate of incorporation, we have the right to redeem shares of our common stock owned by non-U.S. citizens. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. Furthermore, from time to time, legislation has been introduced unsuccessfully in Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and manned by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign flagged vessels.

In addition, the U.S. Coast Guard and the American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

The Merchant Marine Act of 1936 is a federal law that provides, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the U.S. Secretary of Transportation the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our vessels were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, we would not be entitled to compensation for any consequential damages suffered as a result of such purchase or requisition.

Environmental Matters

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the U.S. and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, or at or from our storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. Furthermore, new projects may require approvals and environmental analysis under federal and state laws, including the National Environmental Policy Act and the Endangered Species Act. The resulting costs and liabilities could materially and negatively affect our business, financial condition, results of operations and cash flows. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities.

Environmental and human health and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health. There can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

In accordance with GAAP, we accrue liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for estimable and probable environmental remediation obligations at various sites, including multi-party sites where the EPA, or similar state or Canadian agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites could increase or mitigate our actual joint and several liability exposures.

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of $284 million as of December 31, 2015. Our reserve estimates range in value from approximately $284 million to approximately $457 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, see Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

We generate both hazardous and non-hazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state and Canadian statutes. From time to time, the EPA and state and Canadian regulators consider the adoption of stricter disposal standards for non hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our pipeline or liquids or bulk terminal operations, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The CERCLA or the Superfund law, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons for releases of hazardous substances into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although petroleum is excluded from CERCLA's definition of a hazardous substance, in the course of our ordinary operations, we have and will generate materials that may fall within the definition of hazardous substance. By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state and Canadian statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. For further information, see "—Climate Change" below.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal, state or Canadian authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act pertaining to prevention and response to oil spills. Spill prevention control and countermeasure requirements of the Clean Water Act and some state and Canadian laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release of oil.

EPA Revisions to Ozone National Ambient Air Quality Standard (NAAQS)

As required by the Clean Air Act, EPA establishes National Ambient Air Quality Standards (NAAQS) for how much pollution is permissible and then the states have to adopt rules so their air quality meets the NAAQS. In October 2015, EPA published a rule lowering the ground level ozone NAAQS from 75 ppb to a more stringent 70 ppb standard. This change triggers a process under which EPA will designate the areas of the country that are in or out of attainment with the new NAAQS standard. Then, certain states will have to adopt more stringent air quality regulations to meet the NAAQS standard. These new state rules, which are expected in 2020 or 2021, will likely require the installation of more stringent air pollution controls on newly installed equipment and possibly require retrofitting existing KM facilities with air pollution controls. Given the nationwide implications of the new rule, it is expected that it will have financial impacts for each Kinder Morgan Business Unit.

Climate Change

Studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. Various laws and regulations exist or are under development that seek to regulate the emission of such greenhouse gases, including the EPA programs to control greenhouse gas emissions and state actions to develop statewide or regional programs. The U.S. Congress has in the past considered legislation to reduce emissions of greenhouse gases.

Beginning in December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain greenhouse gases including CO_2 and methane. Our facilities are subject to these requirements. Operational and/or regulatory changes could require additional facilities to comply with greenhouse gas emissions reporting and permitting requirements. Additionally, in September 2015, the EPA published a proposed rule regarding the “Oil and Natural Gas Sector: Emission Standards for New and Modified Sources,” otherwise known as the Proposed New Source Performance Standard (NSPS) Part OOOOa Rule. If finalized, this rule would be the first federal rule under the Clean Air Act to regulate methane as a pollutant and would impose additional pollution control and work practice requirements on applicable Kinder Morgan facilities.

On October 23, 2015, the EPA published as a final rule the Clean Power Plan, which sets interim and final CO2 emission performance rates for power generating units that fire coal, oil or natural gas. The final rule is the focus of legislative discussion in the U.S. Congress and litigation in federal court. On February 10, 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. The ultimate resolution of the final rule’s validity remains uncertain. While we do not operate power plants that would be subject to the Clean Power Plan final rule, it remains unclear what effect the final rule, if it comes into force, might have on the anticipated demand for natural gas, including natural gas that we gather, process, store and transport.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already
have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas “cap and trade” programs. Although many of the state-level initiatives have to date been focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that sources such as our gas-fired compressors and processing plants could become subject to related state regulations. Various states are also proposing or have implemented more strict regulations for greenhouse gases that go beyond the requirements of the EPA. Depending on the particular program, we could be required to conduct monitoring, do additional emissions reporting and/or purchase and surrender emission allowances.

Because our operations, including the compressor stations and processing plants, emit various types of greenhouse gases, primarily methane and CO_2, such new legislation or regulation could increase the costs related to operating and maintaining the facilities. Depending on the particular law, regulation or program, we or our subsidiaries could be required to incur capital expenditures for installing new monitoring equipment of emission controls on the facilities, acquire and surrender allowances for the greenhouse gas emissions, pay taxes related to the greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated entities in the industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our or our subsidiaries’ pipelines, such recovery of costs in all cases is uncertain and may depend on events beyond their control, including the outcome of future rate proceedings before the FERC or other regulatory bodies, and the provisions of any final legislation or other regulations. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Some climatic models indicate that global warming is likely to result in rising sea levels, increased intensity of hurricanes and tropical storms, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. To the extent these phenomena occur, they could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone regions. However, the timing and location of these climate change impacts is not known with any certainty and, in any event, these impacts are expected to manifest themselves over a long time horizon. Thus, we are not in a position to say whether the physical impacts of climate change pose a material risk to our business, financial position, results of operations or cash flows.

Because natural gas emits less greenhouse gas emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives such as the proposed Clean Power Plan could stimulate demand for natural gas by increasing the relative cost of fuels such as coal and oil. In addition, we anticipate that greenhouse gas regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO_2 business segment. However, these positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, greenhouse gas regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

The Department of Homeland Security, referred to in this report as the DHS, has regulatory authority over security at certain high-risk chemical facilities. The DHS has promulgated the Chemical Facility Anti-Terrorism Standards and required all high-risk chemical and industrial facilities, including oil and gas facilities, to comply with the regulatory requirements of these standards. This process includes completing security vulnerability assessments, developing site security plans, and implementing protective measures necessary to meet DHS-defined, risk based performance standards. The DHS has not provided final notice to all facilities that it determines to be high risk and subject to the rule; therefore, neither the extent to which our facilities may be subject to coverage by the rules nor the associated costs to comply can currently be determined, but it is possible that such costs could be substantial.

Other

Employees

We employed 11,290 full-time people at December 31, 2015, including approximately 787 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2016 and 2018. We consider relations with our employees to be good.

Most of our employees are employed by us and a limited number of our subsidiaries and provide services to one or more of our business units. The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated to our subsidiaries. Our human resources department provides the administrative support necessary to implement these payroll and benefits services, and the related administrative costs are allocated to our subsidiaries pursuant to our board-approved expense allocation policy. The effect of these arrangements is that each business unit bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs.

Properties

We believe that we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state, provincial or local government land.

We generally do not own the land on which our pipelines are constructed. Instead, we obtain the right to construct and operate the pipelines on other people’s land for a period of time. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of a majority of the interests have been obtained. Permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits also have been obtained from railroad companies to run along or cross over or under lands or rights-of-way, many of which are also revocable at the grantor’s election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased in fee.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 16 “Reportable Segments” to our consolidated financial statements.

(e) Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on or connected to our internet Website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. Risk Factors.

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Risks Related to Operating our Business

Our businesses are dependent on the supply of and demand for the commodities that we handle.

Our pipelines, terminals and other assets and facilities depend in part on continued production of natural gas, oil and other products in the geographic areas that they serve. Our business also depends in part on the levels of demand for oil, natural gas, coal, steel, chemicals and other products in the geographic areas to which our pipelines, terminals, shipping vessels and other facilities deliver or provide service, and the ability and willingness of our shippers and other customers to supply such demand.
Without additions to oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as in the Alberta oil sands. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our pipelines and related facilities may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as the sharp decline in crude oil prices that began in 2014, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply to our pipelines, terminals and other assets. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil, natural gas, coal and other products. Each of these factors impacts our customers shipping through our pipelines or using our terminals, which in turn could impact the prospects of new contracts for transportation, terminaling or other midstream services, or renewals of existing contracts.

Implementation of new regulations or changes to existing regulations affecting the energy industry could reduce production of and/or demand for natural gas, crude oil, refined petroleum products, coal and other hydrocarbons, increase our costs and have a material adverse effect on our results of operations and financial condition. We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for natural gas, crude oil refined petroleum products and other hydrocarbons.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of nonperformance by our customers or other counterparties, such as hedging counterparties, joint venture partners and suppliers. Some of these counterparties may be highly leveraged and subject to their own operating, market and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness.

In 2015, several of our counterparties defaulted on their obligations to us, and some have filed for bankruptcy protection. We cannot provide any assurance that other financially distressed counterparties will not also default on their obligations to us or file for bankruptcy protection. If a counterparty files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion, of amounts that they owe to us. Additional counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows. Furthermore, in the case of financially distressed customers, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations, financial condition, and cash flows.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry, the coal industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions also may be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. See "-Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us." In addition, decreases in the prices of crude oil, NGL and natural gas will have a negative impact on our operating results and cash flow. See "-The volatility of oil and natural gas prices could have a material adverse effect on our CO2 business segment and businesses within our Natural Gas Pipeline and Products Pipelines business segments."

If global economic and market conditions (including volatility in commodity markets), or economic conditions in the U.S. or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

Our ability to begin and complete construction on expansion and new build projects may be inhibited by difficulties in obtaining permits and rights-of-way, public opposition, cost overruns, inclement weather and other delays.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. A variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way or other regulatory approvals that can be exacerbated by public opposition to our projects, have caused, and may continue to cause, delays in our ability to begin construction projects. Inclement weather, natural disasters and delays in performance by third-party contractors, have resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays could have a material adverse effect on our return on investment, results of operations and cash flows and could result in project cancellations or limit our ability to pursue other growth opportunities.

Additionally, we must obtain and maintain the rights to construct and operate pipelines on other owners' land. If we were to lose these rights or be required to relocate our pipelines, our business could be negatively affected. In addition, we are subject to the possibility of increased costs under our rental agreements with landowners, primarily through rental increases and renewals of expired agreements. Whether we have the power of eminent domain for our pipelines, other than interstate natural gas pipelines, varies from state to state depending upon the type of pipeline-petroleum liquids, natural gas, CO2, or crude oil-and the laws of the particular state. Our interstate natural gas pipelines have federal eminent domain authority. In either case, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy any of the properties on which our pipelines are located.

The acquisition of additional businesses and assets is part of our growth strategy. We may experience difficulties integrating new properties and businesses, and we may be unable to achieve the benefits we expect from any future acquisitions.

Part of our business strategy includes acquiring additional businesses and assets. If we do not successfully integrate acquisitions, we may not realize anticipated operating advantages and cost savings. Integration of acquired companies or assets involves a number of risks, including (i) demands on management related to the increase in our size; (ii) the diversion of management's attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems; and (iv) difficulties in the assimilation and retention of necessary employees.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Difficulties in integration may be magnified if we make multiple acquisitions over a relatively short period of time. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

We face competition from other pipelines and other forms of transportation into the areas we serve as well as with respect to the supply for our pipeline systems.

Any current or future pipeline system or other form of transportation that delivers crude oil, petroleum products or natural gas into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. To the extent that an excess of supply into these areas is created and persists, our ability to re-contract for expiring transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We also could experience competition for the supply of petroleum products or natural gas from both existing and proposed pipeline systems. Several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us.

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to transportation and storage of crude oil, natural gas, refined petroleum products, CO2, coal, chemicals and other products -such as leaks, releases, explosions, mechanical problems and damage caused by third parties. Additional risks to vessels include adverse sea conditions, capsizing, grounding and navigation errors. These risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution and impairment of operations, any of which also could result in substantial financial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. Incidents that cause an interruption of service, such as when unrelated third party construction damages a pipeline or a newly completed expansion experiences a weld failure, may negatively impact our revenues and cash flows while the affected asset is temporarily out of service. In addition, losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

The volatility of oil, NGL and natural gas prices could adversely affect our CO2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.

The revenues, cash flows, profitability and future growth of some of our businesses depend to a large degree on prevailing oil, natural gas and NGL prices. Our CO2 business segment (and the carrying value of its oil, NGL and natural gas producing properties) and certain midstream businesses within our Natural Gas Pipelines segment depend to a large degree, and certain businesses within our Product Pipelines segment depend to a lesser degree, on prevailing oil, NGL and natural gas prices. For 2016, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our distributable cash flow by approximately $6.5 million and each $0.10 per MMBtu change in the average price of natural gas impacts distributable cash flow by approximately $0.6 million, and every 1% change in the ratio of the weighted-average NGL price per barrel to the WTI crude oil price per barrel impacts distributable cash flow by approximately $2.0 million.

Prices for oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) the condition of the U.S. economy; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political instability in the Middle East and elsewhere; (vi) the foreign supply of and demand for oil and natural gas; (vii) the price of foreign imports; and (viii) the availability of alternative fuel sources. We use hedging arrangements to partially mitigate our exposure to commodity prices, but these arrangements also are subject to inherent risks. Please read "- Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income."

A sharp decline in the prices of oil, NGL or natural gas, or a prolonged unfavorable price environment, would result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell oil, NGL, or natural gas, and could have a material adverse effect on the carrying value of our CO2 business segment's proved reserves. If prices fall substantially or remain low for a sustained period and we are not sufficiently protected through hedging arrangements, we may be unable to realize a profit from these businesses and would operate at a loss.

In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The excess or short supply of crude oil or natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity Market Risk.”

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves, revenues and cash flows of the oil and gas producing assets within our CO2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

The development of oil and gas properties involves risks that may result in a total loss of investment.

The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational and market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions, may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.

We engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil, NGL and natural gas. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and natural gas.

The markets for instruments we use to hedge our commodity price exposure generally reflect then-prevailing conditions in the underlying commodity markets. As our existing hedges expire, we will seek to replace them with new hedging arrangements. To the extent underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those statements. In addition, it is not possible for us to engage in hedging transactions that eliminate our exposure to commodity prices.

Our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge. For more information about our hedging activities, see Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Policies and Estimates-Hedging Activities” and Note 13 “Risk Management” to our consolidated financial statements.

Terrorist attacks or “cyber security” events, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or “cyber security” events. These potential targets might include our pipeline systems, terminals, processing plants or operating systems. A cyber security event could affect our ability to operate or control our facilities or disrupt our operations; also, customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

Hurricanes, earthquakes and other natural disasters could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines, terminals and other assets are located in, and our shipping vessels operate in, areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage or destroy our assets and disrupt the supply of the products we transport. Natural disasters can similarly affect the facilities of our customers. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially.

Our business requires the retention and recruitment of a skilled workforce, and the loss of such workforce could result in the failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete the knowledge transfer; and/or (iii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

If we are unable to retain our executive chairman or executive officers, our ability to execute our business strategy, including our growth strategy, may be hindered.

Our success depends in part on the performance of and our ability to retain our executive chairman and our executive officers, particularly Richard D. Kinder, our Executive Chairman and one of our founders, and Steve Kean, our President and Chief Executive Officer. Along with the other members of our senior management, Mr. Kinder and Mr. Kean have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean or our other executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

Our Kinder Morgan Canada and Terminals segments are subject to U.S. dollar/Canadian dollar exchange rate fluctuations.

We are a U.S. dollar reporting company. As a result of the operations of our Kinder Morgan Canada business segments, a portion of our consolidated assets, liabilities, revenues, cash flows and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between U.S. and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our stockholders’ equity under applicable accounting rules.

Risks Related to Financing Our Business

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of December 31, 2015, we had approximately $41 billion of consolidated debt (excluding debt fair value adjustments). Additionally, we and substantially all of our wholly owned subsidiaries are parties to a cross guarantee agreement under which each party to the agreement unconditionally guarantees the indebtedness of each other party, which means that we are liable for the debt of each of such subsidiaries. This level of consolidated debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our consolidated debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our consolidated cash flow is not sufficient to service our consolidated debt, and any future indebtedness that we incur, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 8 “Debt” to our consolidated financial statements.

Our business, financial condition and operating results may be affected adversely by increased costs of capital or a reduction in the availability of credit.

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings (which would have a corresponding impact on the credit ratings of our subsidiaries that are party to the cross guarantee) could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition or expansion opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries’ debt securities.

Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

Our acquisition strategy and growth capital expenditures may require access to external capital. Limitations on our access to external financing sources could impair our ability to grow.

We have limited amounts of internally generated cash flows to fund acquisitions and growth capital expenditures. We may have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisitions and growth capital expenditures. Limitations on our access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, could impair our ability to execute our growth strategy.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2015, approximately $11 billion of our approximately $41 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps. Should interest rates increase, the amount of cash required to service this debt would increase, and our earnings and cash flows could be adversely affected. For more information about our interest rate risk, see Item 7A “Quantitative and Qualitative Disclosures About Market Risk-Interest Rate Risk.”

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial and that may be beneficial to us. Some of the agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more restrictive restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Risks Related to Ownership of Our Capital Stock

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.

We disclose in this report and elsewhere the expected cash dividends on our common stock and on our preferred stock (or depositary shares). This reflects our current judgment, but as with any estimate, it may be affected by inaccurate assumptions and known and unknown risks and uncertainties, many of which are beyond our control. See “Information Regarding Forward-Looking Statements.” If the payment of dividends at the anticipated levels would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, or otherwise to address properly our business prospects, our business would be harmed.

Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated levels. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, might have to choose between addressing those matters and reducing our anticipated dividends. Alternatively, because nothing in our governing documents or credit agreements prohibits us from borrowing to pay dividends, our board of directors may choose to cause us to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed below under "-Risks Related to Financing Our Business-Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic consequences."

Our certificate of incorporation restricts the ownership of our common stock by non-U.S. citizens within the meaning of the Jones Act. These restrictions may affect the liquidity of our common stock and may result in non-U.S. citizens being required to sell their shares at a loss.

The Jones Act requires, among other things, that at least 75% of our common stock be owned at all times by U.S. citizens, as defined under the Jones Act, in order for us to own and operate vessels in the U.S. coastwise trade. As a safeguard to help us maintain our status as a U.S. citizen, our certificate of incorporation provides that, if the number of shares of our common stock owned by non-U.S. citizens exceeds 22%, we have the ability to redeem shares owned by non-U.S. citizens to reduce the percentage of shares owned by non-U.S. citizens to 22%. These redemption provisions may adversely impact the marketability of our common stock, particularly in markets outside of the United States. Further, stockholders would not have control over the timing of such redemption, and may be subject to redemption at a time when the market price or timing of the redemption is disadvantageous. In addition, the redemption provisions might have the effect of impeding or discouraging a merger, tender offer or proxy contest by a non-U.S. citizen, even if it were favorable to the interests of some or all of our stockholders.

Risks Related to Regulation

New regulations, rulemaking and oversight, as well as changes in regulations, by regulatory agencies having jurisdiction over our operations could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and local regulatory authorities. Regulatory actions taken by these agencies have the potential to adversely affect our profitability. Regulation affects almost every part of our business and extends to such matters as (i) rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (ii) the types of services we may offer to our customers; (iii) the contracts for service entered into with our customers; (iv) the certification and construction of new facilities; (v) the integrity, safety and security of facilities and operations; (vi) the acquisition of other businesses; (vii) the acquisition, extension, disposition or abandonment of services or facilities; (viii) reporting and information posting requirements; (ix) the maintenance of accounts and records; and (x) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of such regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws or regulations sometimes arise from unexpected sources. New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes, applicable to us or our assets could have a material adverse impact on our business, financial condition and results of operations. For more information, see Items 1 and 2 "Business and Properties-(c) Narrative Description of Business-Regulation."

The FERC, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, or our customers could file complaints challenging the tariff rates charged by our pipelines, and a successful complaint could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what we are permitted by the FERC, the CPUC, or the NEB to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact upon our operating results.

Our existing rates may also be challenged by complaint. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 16 to our consolidated financial statements, to the rates we charge on our pipelines. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act or analogous state or provincial laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could influence our business, financial position, results of operations and prospects. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, shipping vessels or storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we believe we have utilized operating, handling, and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws in the U.S. such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various Canadian provinces, such as British Columbia's Environmental Management Act, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Items 1 and 2 “Business and Properties-(c) Narrative Description of Business-Environmental Matters.”

Increased regulatory requirements relating to the integrity of our pipelines may require us to incur significant capital and operating expense outlays to comply.

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines issued by the DOT for pipeline companies in the areas of testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs relate to pipeline integrity testing and repairs. Technological advances in in-line inspection tools, identification of additional threats to a pipeline’s integrity and changes to the amount of pipeline determined to be located in “High Consequence Areas” can have a significant impact on integrity testing and repair costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate change regulation at the federal, state, provincial or regional levels could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of greenhouse gases such as methane and CO2, including the EPA programs to control greenhouse gas emissions and state actions to develop statewide or regional programs. Existing EPA regulations require us to report greenhouse gas emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO2 (for example, from our McElmo Dome CO2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further regulate greenhouse gas emissions include establishing greenhouse gas “cap and trade” programs, increased efficiency standards, and incentives or mandates for pollution reduction, use of renewable energy sources, or use of alternative fuels with lower carbon content. For more information about climate change regulation, see Items 1 and 2 “Business and Properties-(c) Narrative Description of Business-Environmental Matters-Climate Change.”

Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities and could require us to install new emission controls on our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Such laws or regulations could also lead to reduced demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, which in turn could adversely affect demand for our products and services.

Finally, some climatic models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. To the extent these phenomena occur, they could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone regions.

Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, as well as reductions in production from existing wells, which could adversely impact the volumes of natural gas transported on our natural gas pipelines and our own oil and gas development and production activities.

We gather, process or transport crude oil, natural gas or NGL from several areas in which the use of hydraulic fracturing is prevalent. Oil and gas development and production activities are subject to numerous federal, state, provincial and local laws and regulations relating to environmental quality and pollution control. The oil and gas industry is increasingly relying on supplies of hydrocarbons from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of hydrocarbons from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by oil and gas exploration and production operators in the completion of certain oil and gas wells. There have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of crude oil, natural gas or NGL and, in turn, adversely affect our revenues, cash flows and results of operations by decreasing the volumes of these commodities that we handle.

In addition, many states are promulgating stricter requirements not only for wells but also compressor stations and other facilities in the oil and gas industry sector. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities and location, emissions into the environment, water discharges, transportation of hazardous materials, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. These laws and regulations may adversely affect our oil and gas development and production activities.

Derivatives regulation could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. The CFTC has proposed new rules pursuant to the Dodd-Frank Act that would institute broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. As the law favors exchange trading and clearing, the Dodd-Frank Act also may require us to move certain derivatives transactions to exchanges where no trade credit is provided. The Dodd-Frank Act, related regulations and the reduction in competition due to derivatives industry consolidation have (i) significantly increased the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduced the availability of derivatives to protect against risks we encounter; and (iii) reduced the liquidity of energy related derivatives.

If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues and cash flows could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

The Jones Act includes restrictions on ownership by non-U.S. citizens of our U.S. point to point maritime shipping vessels, and failure to comply with the Jones Act, or changes to or a repeal of the Jones Act, could limit our ability to operate our vessels in the U.S. coastwise trade, result in the forfeiture of our vessels or otherwise adversely impact our earnings, cash flows and operations.

We are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and manned by predominately U.S. crews. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

See Note 17 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

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 in exhibit 95.1 to this annual report.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our Class P common stock is listed for trading on the NYSE under the symbol “KMI.” The high and low sale prices per Class P share as reported on the NYSE and the dividends declared per share by period for 2015, 2014 and 2013, are provided below.

	Price Range		Declared Cash
	Low	High	Dividends(a)
2015			
First Quarter	$39.45	$42.93	$0.48
Second Quarter	38.33	44.71	0.49
Third Quarter	25.81	38.58	0.51
Fourth Quarter	14.22	32.89	0.125
2014			
First Quarter	$30.81	$36.45	$0.42
Second Quarter	32.10	36.50	0.43
Third Quarter	35.20	42.49	0.44
Fourth Quarter	33.25	43.18	0.45
2013			
First Quarter	$35.74	$38.80	$0.38
Second Quarter	35.52	41.49	0.40
Third Quarter	34.54	40.45	0.41
Fourth Quarter	32.30	36.68	0.41

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(a) Dividend information is for dividends declared with respect to that quarter. Generally, our declared dividends for our Class P common stock are paid on or about the 16th day of each February, May, August and November.

As of February 11, 2016, we had 12,739 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

For information on our equity compensation plans, see Note 10 “Share-based Compensation and Employee Benefits—Share-based Compensation” to our consolidated financial statements.

Our Purchases of Our Warrants

Period	Total number of securities purchased(a)	Average price paid per security	Total number of securities purchased as part of publicly announced plans(a)	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs
October 1 to October 31, 2015	212,345	$0.90	212,345	$90,428,906
November 1 to November 30, 2015	—	—	—	90,428,906
December 1 to December 31, 2015	—	—	—	90,428,906
Total Warrants				$90,428,906

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(a) On June 12, 2015, we announced that our board of directors had approved a warrant repurchase program authorizing us to repurchase up to $100 million of warrants.

Item 6. Selected Financial Data.

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report for more information.

Five-Year Review

Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except per share and ratio data)				
Income and Cash Flow Data:					
Revenues	$14,403	$16,226	$14,070	$9,973	$7,943
Operating income	2,447	4,448	3,990	2,593	1,423
Earnings from equity investments	384	406	327	153	226
Income from continuing operations	208	2,443	2,696	1,204	449
(Loss) income from discontinued operations, net of tax	—	—	(4)	(777)	211
Net income	208	2,443	2,692	427	660
Net income attributable to Kinder Morgan, Inc.	253	1,026	1,193	315	594
Net income available to common stockholders	227	1,026	1,193	315	594
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$0.10	$0.89	$1.15	$0.56	$0.70
Basic and Diluted (Loss) Earnings Per Common Share From Discontinued Operations	—	—	—	(0.21)	0.04
Total Basic and Diluted Earnings Per Common Share	$0.10	$0.89	$1.15	$0.35	$0.74
Class A Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations				$0.47	$0.64
Basic and Diluted (Loss) Earnings Per Common Share From Discontinued Operations				(0.21)	0.04
Total Basic and Diluted Earnings Per Common Share				$0.26	$0.68
Basic Weighted Average Number of Common Shares Outstanding:					
Class P shares	2,187	1,137	1,036	461	118
Class A shares				446	589
Diluted Weighted Average Number of Common Shares Outstanding:					
Class P shares	2,193	1,137	1,036	908	708
Class A shares				446	589
Dividends per common share declared for the period(a)(b)	$1.605	$1.740	$1.600	$1.400	$1.050
Dividends per common share paid in the period(a)	1.93	1.70	1.56	1.34	0.74
Balance Sheet Data (at end of period):					

Net property, plant and equipment	$40,547	$38,564	$35,847	$30,996	$17,926
Total assets	84,104	83,049	75,071	68,133	30,658
Long-term debt(c)	40,732	38,312	31,910	29,409	13,261

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.

(b) 2011 declared dividend per share was prorated for the portion of the first quarter we were a public company ($0.14 per share). If we had been a public company for the entire year, the 2011 declared dividend would have been $1.20 per share.

(c) Excludes debt fair value adjustments. Increases to long-term debt for debt fair value adjustments totaled $1,674 million, $1,785 million, $1,863 million, $2,479 million and $1,036 million as of December 31, 2015, 2014, 2013, 2012, and 2011, respectively.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties—(c) Narrative Description of Business—Business Strategy;" (ii) a description of developments during 2015, found in Items 1 and 2 "Business and Properties—(a) General Development of Business—Recent Developments;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

Inasmuch as the discussion below and the other sections to which we have referred you pertain to management's comments on financial resources, capital spending, our business strategy and the outlook for our business, such discussions contain forward-looking statements. These forward-looking statements reflect the expectations, beliefs, plans and objectives of management about future financial performance and assumptions underlying management's judgment concerning the matters discussed, and accordingly, involve estimates, assumptions, judgments and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to any differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in Item 1A "Risk Factors" and at the beginning of this report in "Information Regarding Forward-Looking Statements."

General

Our business model, through our ownership and operation of energy related assets, is built to support two principal objectives:

- helping customers by providing safe and reliable energy, bulk commodity and liquids products transportation, storage and distribution; and

- creating long-term value for our shareholders.

To achieve these objectives, we focus on providing fee-based services to customers from a business portfolio consisting of energy-related pipelines, natural gas storage, processing and treating facilities, and bulk and liquids terminal facilities. We also produce and sell crude oil. Our reportable business segments are based on the way our management organizes our enterprise, and each of our business segments represents a component of our enterprise that engages in a separate business activity and for which discrete financial information is available.

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;

- Products Pipelines—the ownership and operation of refined petroleum products and crude oil and condensate pipelines that deliver refined petroleum products (gasoline, diesel fuel and jet fuel), NGL, crude oil, condensate and bio-fuels to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

39

- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport; and

- Other—primarily other miscellaneous assets and liabilities including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with legacy trading activities; and (iii) other miscellaneous assets and liabilities.

As an energy infrastructure owner and operator in multiple facets of the various U.S. and Canadian energy industries and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, the Texas Intrastate Natural Gas Pipeline operations, currently derives approximately 73% of its sales and transport margins from long-term transport and sales contracts. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2015, the remaining average contract life of our natural gas transportation contracts (including intrastate pipelines' purchase and sales contracts) was approximately six years.

Our midstream assets provide gathering and processing services for natural gas and gathering services for crude oil. These assets are generally fee-based and the revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into their base components, are affected by the volumes of natural gas made available to our systems. Such volumes are impacted by producer rig count and drilling activity. In addition to fee based arrangements, we also provide some services based on percent-of-proceeds, percent-of-index and keep-whole contracts some of which may include minimum volume requirements. Our service contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2015, had a remaining average contract life of approximately nine years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2016, and utilizing the average oil price per barrel contained in our 2016 budget, approximately 99% of our revenue is based on a fixed fee or floor price, and 1% fluctuates with the price of oil. In the long-term, our success in this portion of the CO_2 business segment is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, NGL and CO_2 sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with all hedges allocated to oil, was $73.11 per barrel in 2015, $88.41 per barrel in 2014, and $92.70 per barrel in 2013. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $47.56 per barrel in 2015, $86.48 per barrel in 2014, and $94.94 per barrel in 2013.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. Our liquids terminals business generally has longer-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which on average is approximately four years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. As with our refined petroleum products pipeline transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are coal, petroleum coke, and steel. For the most part, we have contracts for this business that contain minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize our terminals for all or a specified percentage of their handling and storage needs. The profitability of our minimum volume contracts is generally unaffected by short-term variation in economic conditions; however, to the extent we expect volumes above the minimum and/or have contracts which are volume-based we can be sensitive to changing market conditions. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods. Our eight Jones Act qualified tankers operate in the marine transportation of crude oil, condensate and refined products in the U.S. and are currently operating pursuant to multi-year charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

The profitability of our refined petroleum products pipeline transportation and storage business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. We also have approximately 55 liquids terminals in this business segment that store fuels and offer blending services for ethanol and biofuels. The transportation and storage volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

Our crude and condensate transportation services are primarily provided either pursuant to (i) long-term contracts that normally contain minimum volume commitments or (ii) through terms prescribed by the toll settlements with shippers and approved by regulatory authorities. As a result of these contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term, however, in the longer term the revenues and earnings we realize from our crude and condensate pipelines in the U.S. and Canada are affected by the volumes of crude and condensate available to our pipeline systems, which are impacted by the level of oil and gas drilling activity in the respective producing regions that we serve. Our petroleum condensate processing facility splits condensate into its various components, such as light and heavy naphtha, under a long-term fee-based agreement with a major integrated oil company.

A portion of our business portfolio (including the Kinder Morgan Canada business segment, the Canadian portion of the Cochin Pipeline, and the bulk and liquids terminal facilities located in Canada) transact in and/or use the Canadian dollar as the functional currency, which affect segment results due to the variability in U.S. - Canadian dollar exchange rates.

In our discussions of the operating results of individual businesses that follow (see “—Results of Operations” below), we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) the economic useful lives of our assets and related depletion rates; (ii) the fair values used to assign purchase price from business combinations, determine possible asset impairment charges, and calculate the annual goodwill impairment test; (iii) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (iv) provisions for uncollectible accounts receivables; (v) exposures under contractual indemnifications; and (vi) unbilled revenues.

For a summary of our significant accounting policies, see Note 2 "Summary of Significant Accounting Policies" to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Acquisition Method of Accounting

For acquired businesses, we generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition. Determining the fair value of these items requires management's judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired, the liabilities assumed and any noncontrolling interest in the investee, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. For more information on our acquisitions and application of the acquisition method, see Note 3 "Acquisitions and Divestitures" to our consolidated financial statements.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on environmental matters, see Items 1 and 2 "Business and Properties—(c) Narrative Description of Business—Environmental Matters". For more information on our environmental disclosures, see Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

Legal Matters

Many of our operations are regulated by various U.S. and Canadian regulatory bodies and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on legal proceedings, see Note 17 "Litigation, Environmental and Other Contingencies" to our consolidated financial statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate goodwill for impairment on May 31 of each year. At year end and during other interim periods we evaluate our reporting units for events and changes that could indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as “Other intangibles, net” in our accompanying consolidated balance sheets.

For more information on our December 31, 2015 goodwill impairment evaluation and amortizable intangibles, see Note 8 “Goodwill” to our consolidated financial statements.

Estimated Net Recoverable Quantities of Oil and Gas

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted or amortized into income, and the presentation of supplemental information on oil and gas producing activities. The expected future cash flows to be generated by oil and gas producing properties used in testing for impairment of such properties also rely in part on estimates of net recoverable quantities of oil and gas.

Proved reserves are the estimated quantities of oil and gas that geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. For more information on our ownership interests in the net quantities of proved oil and gas reserves and our measures of discounted future net cash flows from oil and gas reserves, please see “Supplemental Information on Oil and Gas Producing Activities (Unaudited)”.

DD&A expense on our proved oil and gas properties is calculated using the unit of production (UOP) method. The reserves that are used to determine the UOP depletion rate for leasehold acquisition and the costs to acquire proved properties is the total of our developed and undeveloped proved reserves which are known as total proved reserves. The UOP depreciation rate for our tangible lease and well equipment costs, including development costs and exploration costs associated with successful drilling projects, is calculated based upon total proved developed reserves. Our estimated future well plugging and abandonment costs along with future expected salvage values are considered in the UOP DD&A expense calculation. For our oil and gas producing properties that have no proved reserves, the UOP depreciation rate is based on each property’s risk-adjusted probable reserves and NYMEX forward curve prices.

The sustained deterioration in the long-term outlook for commodity prices was a triggering event that required us to perform impairment testing of our assets that are sensitive to such commodity prices. During 2015, we performed a two-step impairment testing of certain long-lived assets within our CO2 segment, which resulted in the impairment of certain of our oil and gas producing properties in the amount of $399 million for the year ended December 31, 2015.

As of December 31, 2015, the net book value of productive properties, plant and equipment associated with our oil and gas proved reserves was approximately $932 million, which included 49.5 million barrels of oil equivalent of estimated proved developed reserves, and the DD&A expense recorded on these properties in 2015 was $376 million. If the estimates of proved reserves used in the unit-of-production calculation had been lower by 5%, DD&A expense in 2015 would have increased by approximately $15 million.

Continued lower commodity prices as indicated by forward curve pricing that is used in testing for impairment, estimated total proved and risk-adjusted probable oil and gas reserves, and related expected future cash flows, may result in additional impairments of our oil producing interests and increased DD&A expense in 2016. See Note 4 "Impairments and Disposals" to our consolidated financial statements.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices and to balance our exposure to fixed and variable interest rates, and we believe that these hedges are generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged, and any ineffective portion of the hedge gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately. We may or may not apply hedge accounting to our derivative contracts depending on the circumstances. All of our derivative contracts are recorded at estimated fair value. For more information on our hedging activities, see Note 14, “Risk Management” to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. As of December 31, 2015, our pension plans were underfunded by $604 million and our other postretirement benefits plans were underfunded by $184 million. Our pension and other postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. For 2015, we selected our discount rates by matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities. The selection of these assumptions is further discussed in Note 10 “Share-based Compensation and Employee Benefits” to our consolidated financial statements. Effective January 1, 2016, we changed our estimate of the service and interest cost components of net periodic benefit cost (credit) for our pension and other postretirement benefit plans. The new estimate utilizes a full yield curve approach in the estimation of these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The new estimate provides a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows and their corresponding spot rates. The change does not affect the measurement of our pension and postretirement benefit obligations and it is accounted for as a change in accounting estimate, which is applied prospectively. The change in the service and interest costs going forward will not be significant.
Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income over either the period of expected future service of active participants, or over the expected future lives of inactive plan participants. As of December 31, 2015, we had deferred net losses of approximately $535 million in pretax accumulated other comprehensive loss and noncontrolling interests related to our pension and other postretirement benefits.

The following table shows the impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2015:

	Pension Benefits		Other Postretirement Benefits	
	Net benefit cost (income)	Change in funded status(a)	Net benefit cost (income)	Change in funded status(a)
	(In millions)			
One percent increase in:				
Discount rates	$10	$219	$2	$44
Expected return on plan assets	(23)	—	(4)	—
Rate of compensation increase	3	(10)	—	—
Health care cost trends	—	—	4	(31)
One percent decrease in:				
Discount rates	11	(258)	—	(51)
Expected return on plan assets	23	—	4	—
Rate of compensation increase	(3)	9	—	—
Health care cost trends	—	—	(2)	27

(a) Includes amounts deferred as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations.

Income Taxes

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached. In addition, we do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

In determining the deferred income tax asset and liability balances attributable to our investments, we have applied an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments.

Results of Operations

Non-GAAP Measures

The non-GAAP financial measures, DCF before certain items and segment EBDA before certain items are presented below under "—Distributable Cash Flow" and "—Consolidated Earnings Results," respectively. Certain items are items that are required by GAAP to be reflected in net income, but typically either do not have a cash impact, or by their nature are separately identifiable from our normal business operations and, in our view, are likely to occur only sporadically.

Our non-GAAP measures described below should not be considered as an alternative to GAAP net income or any other GAAP measure. DCF before certain items and segment EBDA before certain items are not financial measures in accordance with GAAP and have important limitations as analytical tools. You should not consider either of these non-GAAP measures in isolation or as substitutes for an analysis of our results as reported under GAAP. Because DCF before certain items excludes some but not all items that affect net income and because DCF measures are defined differently by different companies in our industry, our DCF before certain items may not be comparable to DCF measures of other companies. Our computation of segment EBDA before certain items has similar limitations. Management compensates for the limitations of these non-GAAP 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 before certain items is an overall performance metric we use to estimate the ability of our assets to generate cash flows on an ongoing basis and as a measure of cash available to pay dividends. We believe the primary measure of company performance used by us, investors and industry analysts is cash generation performance. Therefore, we believe DCF before certain items is an important measure to evaluate our operating and financial performance and to compare it with the performance of other publicly traded companies within the industry.

The table below details the reconciliation of Net Income to DCF before certain items:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Net Income	$208	$2,443	$2,692
Add/(Subtract):			
Certain items before book tax(a)(b)	1,781	14	(609)
Book tax certain items(b)(c)	(340)	(117)	(39)
Certain items after book tax	1,441	(103)	(648)
Net income before certain items	1,649	2,340	2,044
Add/(Subtract):			
Net income attributable to third-party noncontrolling interests(d)	(18)	(12)	(5)
DD&A expense(e)	2,683	2,390	2,142
Book taxes(f)	976	840	847
Cash taxes(g)	(32)	(448)	(552)
Other items(h)	32	17	6
Sustaining capital expenditures(i)	(565)	(509)	(414)
Declared distributions to noncontrolling interests(j)	—	(2,000)	(2,355)
Subtotal	3,076	278	(331)
DCF before certain items available to equity	4,725	2,618	1,713
Preferred stock dividends	(26)	—	—
DCF before certain items available to common stockholders	$4,699	$2,618	$1,713
Weighted average common shares outstanding for dividends(k)	2,200	1,312	1,040
DCF per common share before certain items	$2.14	$2.00	$1.65
Declared dividend per common share	1.605	1.740	1.600

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(a) Consists of certain items summarized in footnotes (b) through (e) to the "—Consolidated Earnings Results" table included below, 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) 2015 amount includes a $175 million non-cash pre-tax impairment ($84 million net after-tax impact to common stockholders) of a terminal facility reflecting the impact of an agreement to adjust certain payment terms under a contract with a coal customer, which occurred after the issuance of our 2015 fourth quarter earnings release containing our preliminary financial results ($175 million in certain items before book tax and $(48) million in book tax certain items).

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

(d) Represents net income allocated to third-party ownership interests in consolidated subsidiaries other than our former master limited partnerships. 2015 amount excludes losses attributable to noncontrolling interests of $63 million related to impairments included as certain items, which includes a $43 million loss attributable to noncontrolling interests associated with the impairment discussed in footnote (b) above.

(e) Includes DD&A, amortization of excess cost of equity investments and our share of equity investee's DD&A of $323 million, $305 million and $297 million in 2015, 2014 and 2013, respectively.

(f) Excludes book tax certain items and includes income tax allocated to the segments. 2015, 2014 and 2013 amounts also include $72 million, $75 million and $66 million, respectively, of our share of taxable equity investee's book tax expense.

(g) Includes our share of taxable equity investee's cash taxes of $(19) million, $(27) million and $(30) million in 2015, 2014 and 2013, respectively.

(h) For 2015, consists primarily of non-cash compensation associated with our restricted stock awards program and for 2014 and 2013 consists primarily of excess coverage from our former master limited partnerships.

(i)

Includes our share of equity investee’s sustaining capital expenditures of $(70) million, $(59) million and $(48) million in 2015, 2014 and 2013, respectively.

(j) Represents distributions to KMP and EPB limited partner units formerly owned by the public for the respective period.

(k) Includes restricted stock awards that participate in dividends and, for 2015, the dilutive effect of warrants. 2014 amount also includes the shares issued on November 26, 2014 for the Merger Transactions as if outstanding for the entire fourth quarter which differs from our GAAP presentation on our Consolidated Statement of Income.

Consolidated Earnings Results

In the Results of Operations table below and in the business segment tables that follow, segment EBDA before certain items is calculated by adjusting the segment earnings before DD&A for the applicable certain item amounts in the footnotes to those tables.

In general, interest expense, general and administrative expenses, DD&A, unallocable interest income and income taxes and net income attributable to noncontrolling interests are not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. 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.

We evaluate business segment performance primarily based on segment EBDA before certain items in relation to the level of capital allocated and consider this to be an important measure of our business segment performance. We account for intersegment sales at market prices, which are eliminated in consolidation.

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Segment earnings before DD&A(a)			
Natural Gas Pipelines	$3,063	$4,259	$4,207
CO_2	657	1,240	1,435
Terminals	849	944	836
Products Pipelines	1,100	856	602
Kinder Morgan Canada	163	182	424
Other	(53)	13	(5)
Total segment earnings before DD&A(b)	5,779	7,494	7,499
DD&A expense	(2,309)	(2,040)	(1,806)
Amortization of excess cost of equity investments	(51)	(45)	(39)
Other revenues	37	36	36
General and administrative expenses(c)	(690)	(610)	(613)
Interest expense, net of unallocable interest income(d)	(2,055)	(1,807)	(1,688)
Income from continuing operations before unallocable income taxes	711	3,028	3,389
Unallocable income tax expense	(503)	(585)	(693)
Income from continuing operations	208	2,443	2,696
Loss from discontinued operations, net of tax(e)	—	—	(4)
Net income	208	2,443	2,692
Net loss (income) attributable to noncontrolling interests	45	(1,417)	(1,499)
Net income attributable to Kinder Morgan, Inc.	253	1,026	1,193
Preferred Stock Dividends	(26)	—	—
Net Income Available to Common Stockholders	$227	$1,026	$1,193

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(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 of goodwill and losses on impairments and disposals of long-lived assets, net and equity investments. 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 earnings for the years ended December 31, 2015, 2014 and 2013 were $61 million, $63 million and $49 million, respectively.

48

Certain item footnotes

(b) 2015, 2014 and 2013 amounts include decreases (increase) in earnings of $1,783 million, $45 million and $(573) million, respectively, related to the combined effect of the certain items impacting segment earnings before DD&A from continuing operations and disclosed below in our management discussion and analysis of segment results.

(c) 2015, 2014 and 2013 amounts include (increase) decreases to expense of $(25) million, $28 million and $8 million, respectively, related to the combined effect of the certain items related to general and administrative expenses disclosed below in "—General and Administrative, Interest, and Noncontrolling Interests."

(d) 2015, 2014 and 2013 amounts include decreases in expense of $27 million, $3 million and $32 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."

(e) 2013 amount represents an incremental loss related to the sale of our FTC Natural Gas Pipelines disposal group effective November 1, 2012.

Year Ended December 31, 2015 vs. 2014

The certain item totals reflected in footnotes (b), (c) and (d) to the tables above accounted for $1,767 million of the decrease in income from continuing operations before unallocable income taxes in 2015 as compared to 2014 (representing the difference between decreases of $1,781 million and $14 million in total income from continuing operations before unallocable income taxes for 2015 and 2014, respectively). After giving effect to these certain items, the remaining decrease of $550 million (18%) from the prior year in income from continuing operations before unallocable income taxes is primarily attributable to increased DD&A expense, general and administrative expense and interest expense, net of unallocable interest income. As explained further below, our total segment earnings before DD&A did not change significantly when compared to the prior year as unfavorable commodity prices affecting our CO_2 business segment were offset by increased results from our Products Pipelines, Terminals and Natural Gas Pipelines business segments.

Year Ended December 31, 2014 vs. 2013

The certain item totals reflected in footnotes (b), (c) and (d) to the tables above accounted for $627 million of the decrease in income from continuing operations before unallocable income taxes in 2014, when compared to 2013 (combining a decrease of $14 million and an increase of $613 million in total income from continuing operations before unallocable income taxes for 2014 and 2013, respectively). After giving effect to these certain items, the remaining increase of $266 million (10%) from the prior year in income from continuing operations before unallocable income taxes relates to better overall performance primarily from our Natural Gas Pipelines, Products Pipelines and Terminals segments in 2014.

Natural Gas Pipelines

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except operating statistics)		
Revenues(a)	$8,725	$10,168	$8,617
Operating expenses	(4,738)	(6,241)	(5,235)
Loss on impairment of goodwill(b)	(1,150)	—	—
Loss on impairments and disposals of long-lived assets and equity investments, net(b)	(148)	(5)	(37)
Other income (expense)	3	—	(4)
Earnings from equity investments	351	318	297
Interest income and Other, net	24	25	578
Income tax expense	(4)	(6)	(9)
Segment earnings before DD&A from continuing operations(b)	3,063	4,259	4,207
Discontinued operations(c)	—	—	(4)
Certain items(b)(c)	1,062	(190)	(486)
EBDA before certain items	$4,125	$4,069	$3,717
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$(1,479)	$1,339	
EBDA before certain items	$56	$352	
Natural gas transport volumes (BBtu/d)(d)	28,398	27,064	25,144
Natural gas sales volumes (BBtu/d)(e)	2,419	2,334	2,458
Natural gas gathering volumes (BBtu/d)(f)	3,540	3,394	2,959
Crude/condensate gathering volumes (MBbl/d)(g)	340	298	225

Certain item footnotes

(a) 2015 amount includes increase in revenues of $32 million and 2014 and 2013 amounts include decreases in revenues of $2 million and $16 million, respectively, related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. 2015 and 2014 amounts also include increases in revenues of $200 million and $198 million, respectively, associated with amounts collected on the early termination of long-term natural gas transportation contracts on KMLP.

(b) In addition to the revenue certain items described in footnote (a) above: 2015 amount also includes (i) $1,150 million of losses related to goodwill impairments on our non-regulated midstream assets; (ii) $52 million of losses related to disposals of our non-regulated midstream assets; (iii) $47 million of losses related to impairments on our non-regulated midstream assets; and (iv) $45 million net decrease in earnings related to project write-offs and other certain items. 2014 amount also includes $6 million decrease in earnings from other certain items. 2013 amount also includes (i) a $558 million gain from the remeasurement of a previously held 50% equity interest in Eagle Ford to fair value; (ii) a $36 million gain from the sale of certain Gulf Coast offshore and onshore TGP supply facilities; (iii) a $65 million non-cash equity investment impairment charge related to our ownership interest in NGPL Holdco LLC; and (iv) a combined $23 million decrease in earnings from other certain items.

(c) Represents a loss from the sale of our FTC Natural Gas Pipelines disposal group.

Other footnotes

(d) Includes pipeline volumes for Kinder Morgan North Texas Pipeline LLC, Monterrey, TransColorado Gas Transmission Company LLC,

MEP, KMLP, FEP, TGP, EPNG, South Texas Midstream, the Texas Intrastate Natural Gas Pipeline operations, CIG, WIC, CPG, SNG, Elba Express, Sierrita Gas Pipeline LLC, NGPL, 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.

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

(f) Includes Oklahoma Midstream, South Texas Midstream, Eagle Ford, North Texas Midstream, Camino Real Gathering Company, L.L.C. (Camino Real), Kinder Morgan Altamont LLC, KinderHawk, Endeavor, Bighorn Gas Gathering L.L.C., Webb Duval Gatherers, Fort Union Gas Gathering L.L.C., 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.

(g) 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.

Following is information, including discontinued operations, related to the increases and decreases in both EBDA and revenues before certain items in 2015 and 2014, when compared with the respective prior year:

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Hiland Midstream	$140	n/a	$404	n/a
TGP	36	4%	48	4%
EPNG	34	8%	56	10%
EagleHawk(a)	31	443%	n/a	n/a
Texas Intrastate Natural Gas Pipeline Operations	17	5%	(1,231)	(30)%
KinderHawk	(67)	(34)%	(69)	(31)%
Oklahoma Midstream(b)	(38)	(57)%	(247)	(47)%
KMLP	(34)	(61)%	(34)	(50)%
CPG	(24)	(29)%	(24)	(24)%
Altamont Midstream	(21)	(35)%	(60)	(37)%
South Texas Midstream(b)	(9)	(3)%	(417)	(25)%
All others (including eliminations)(b)	(9)	(1)%	95	7%
Total Natural Gas Pipelines	$56	14%	$(1,479)	(15)%

n/a - not applicable

(a) Equity investment.

(b) Includes amounts previously presented as part of "Copano operations."

The significant changes in our Natural Gas Pipelines business segment's EBDA before certain items in the comparable years of 2015 and 2014 included the following:

- increase of $140 million from our February 2015 acquisition of the Hiland Midstream asset;
- increase of $36 million (4%) from TGP primarily due to higher revenues from firm transportation and storage services due largely to expansion projects placed in service in the fourth quarter 2014 and during 2015. Partially offsetting this was an increase in the provision for revenue sharing during 2015, lower transportation usage revenues and natural gas park and loan revenues due to milder winter weather in 2015 and higher ad valorem taxes;
- increase of $34 million (8%) from EPNG due largely to additional firm transport revenues due, in part, to additional demand from Mexico;
- increase of $31 million (443%) from EagleHawk driven by higher volumes and lower pipeline integrity costs;
- increase of $17 million (5%) 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) due largely to higher transportation and natural gas sales margins as a result of new customer contracts, partially offset by lower processing margins due to the non-renewal of a customer contract in the second quarter of 2014 and lower storage margins. The decrease in revenues of $1,231 million and associated decrease in costs of goods sold were caused by lower natural gas prices;
- decrease of $67 million (34%) from KinderHawk primarily due to the expiration of a minimum volume contract;
- decrease of $38 million (57%) from Oklahoma Midstream primarily due to lower commodity prices and lower volumes. Lower revenues of $247 million and associated decrease in costs of goods sold were also due to lower commodity prices;
- decrease of $34 million (61%) from KMLP as a result of a customer contract buyout in the third quarter of 2014;
- decrease of $24 million (29%) from CPG due primarily to lower transport revenues as a result of contract expirations;
- decrease of $21 million (35%) from Altamont Midstream primarily due to lower commodity prices partially offset by higher volumes; and
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decrease of $9 million (3%) from South Texas Midstream primarily due to lower commodity prices, partially offset by higher gathering and processing volumes. Lower revenues of $417 million and associated decrease in costs of goods sold were due to lower commodity prices.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Copano operations (including Eagle Ford)(a)	$163	n/a	$998	n/a
TGP	121	15%	151	14%
EPNG	37	10%	59	11%
Ruby(b)	18	199%	n/a	n/a
Citrus(b)	13	15%	n/a	n/a
Texas Intrastate Natural Gas Pipeline Operations	11	3%	432	12%
WIC	(24)	(17)%	(26)	(15)%
SNG	(17)	(4)%	(25)	(4)%
All others (including eliminations)	30	3%	(250)	(24)%
Total Natural Gas Pipelines	$352	9%	$1,339	16%

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n/a – not applicable

(a) On May 1, 2013, as part of Copano acquisition, we acquired the remaining 50% interest of Eagle Ford. Prior to that date, we recorded earnings from Eagle Ford under the equity method of accounting, but we received distributions in amounts essentially equal to equity earnings plus our share of depreciation and amortization expenses less our share of sustaining capital expenditures (those capital expenditures which do not increase the capacity or throughput).

(b) Equity investment.

The significant changes in our Natural Gas Pipelines business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $163 million from full year ownership of our Copano operations, which we acquired effective May 1, 2013, including benefits from higher gathering volumes from the Eagle Ford Shale;
- increase of $121 million (15%) from TGP primarily due to higher revenues from (i) firm transportation and storage services due largely to new expansion projects placed in service in the latter part of 2013 and during 2014 and (ii) usage and interruptible transportation services due to weather-related demand relative to 2013. Partially offsetting the increase in 2014 revenues were higher operating and franchise tax expenses in 2014, and a favorable operational sales margin in 2013;
- increase of $37 million (10%) from EPNG, primarily driven by higher transportation revenues and throughput due to increased deliveries to California for storage refill and increased demand in Mexico. The increase in revenues was partially offset by higher field operation and maintenance expenses;
- increase of $18 million (199%) from Ruby due largely to higher contracted firm transportation revenues and lower interest expense;
- increase of $13 million (15%) from Citrus assets, primarily due to higher transportation revenues and reduction in property taxes;
- increase of $11 million (3%) from 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), due largely to higher natural gas sales and transportation margins driven by higher volumes, additional customer contracts and colder weather in the first quarter of 2014, which were offset by lower processing margin due to non-renewal of a certain contract;
- decrease of $24 million (17%) from WIC, primarily due to lower reservation revenue as a result of rate reductions pursuant to its FERC Section 5 rate settlement effective November 1, 2013 and lower rates on contract renewals; and
- decrease of $17 million (4%) from SNG, driven by lower reservation and usage revenues due to rate reductions pursuant to its rate case settlement effective September 1, 2013; partially offset by incremental revenues from increased firm transportation services and revenue related to an expansion project that was placed in service in late 2013.

CO2

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except operating statistics)		
Revenues(a)	$1,699	$1,960	$1,857
Operating expenses	(432)	(494)	(439)
Loss on impairments and disposals of long-lived assets, net(b)	(606)	(243)	—
Earnings from equity investments(b)	(3)	25	24
Income tax expense	(1)	(8)	(7)
Segment earnings before DD&A(b)	657	1,240	1,435
Certain items(b)	484	218	(3)
EBDA before certain items	$1,141	$1,458	$1,432

Change from prior period	Increase/(Decrease)	
Revenues before certain items	$(384)	$81
EBDA before certain items	$(317)	$26

Southwest Colorado CO_2 production (gross) (Bcf/d)(c)	1.2	1.3	1.2
Southwest Colorado CO_2 production (net) (Bcf/d)(c)	0.6	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	33.8	33.2	30.7
SACROC oil production (net)(MBbl/d)(e)	28.1	27.6	25.5
Yates oil production (gross)(MBbl/d)(d)	19.0	19.5	20.4
Yates oil production (net)(MBbl/d)(e)	8.5	8.8	9.0
Katz, Goldsmith, and Tall Cotton Oil Production - Gross (MBbl/d)(d)	5.7	4.9	3.4
Katz, Goldsmith, and Tall Cotton Oil Production - Net (MBbl/d)(e)	4.8	4.1	2.8
NGL sales volumes (net)(MBbl/d)(e)	10.4	10.1	9.9
Realized weighted-average oil price per Bbl(f)	$73.11	$88.41	$92.70
Realized weighted-average NGL price per Bbl(g)	$18.35	$41.87	$46.43

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Certain item footnotes

(a) 2015, 2014 and 2013 amounts include unrealized gains of $138 million, $25 million and $3 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales. 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: 2015 amount includes (i) oil and gas property impairments of $399 million; (ii) project write-offs of $207 million; and (iii) a $26 million decrease in equity earnings for our share of a project write-off. 2014 amount also includes oil and gas property impairments of $243 million.

Other footnotes

(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 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. Hedge gains/losses for Oil and NGL are included with Crude Oil.

(g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements. Hedge gains/losses for Oil and NGL are included with Crude Oil.

Following is information related to the increases and decreases in both EBDA and revenues before certain items in 2015 and 2014, when compared with the respective prior year:
Year Ended December 31, 2015 versus Year Ended December 31, 2014

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$(115)	(26)%	$(116)	(23)%
Oil and Gas Producing Activities	(202)	(20)%	(303)	(20)%
Intrasegment eliminations	—	—%	35	42%
Total CO2	$(317)	(22)%	$(384)	(20)%

The primary changes in our CO_2 business segment's EBDA before certain items in the comparable years of 2015 and 2014 was primarily driven by $405 million from lower commodity prices partially offset by $62 million of increased volumes and $27 million in reduced operating expenses.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation Activities	$56	14%	$59	13%
Oil and Gas Producing Activities	(30)	(3)%	26	2%
Intrasegment Eliminations	—	—%	(4)	5%
Total CO2	$26	2%	$81	4%

The primary changes in our CO_2 business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $56 million (14%) from source and transportation activities primarily due to higher revenues driven by an increase of average CO_2 contract prices and higher CO_2 volumes partly offset by higher labor costs, power costs, property taxes and severance taxes.; and
- decrease of $30 million (3%) from oil and gas producing activities primarily driven by higher operating expenses as a result of (i) incremental well work costs; (ii) increased power costs; and (iii) higher property and severance tax expenses related to higher revenues. Also contributing to the decrease was lower crude oil and NGL prices, which were offset by improved net crude oil production.

Terminals

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except operating statistics)		
Revenues(a)	$1,879	$1,718	$1,410
Operating expenses	(836)	(746)	(657)
Loss on impairments and disposals of long-lived assets and equity investments, net(b)(c)	(195)	(29)	73
Other income	1	—	1
Earnings from equity investments	21	18	22
Interest income and Other, net	8	12	1
Income tax expense	(29)	(29)	(14)
Segment earnings before DD&A(b)(c)	849	944	836
Certain items, net(b)(c)	206	35	(38)
EBDA before certain items	$1,055	$979	$798
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$156	$298	
EBDA before certain items	$76	$181	
Bulk transload tonnage (MMtons)(d)	63.2	79.8	82.1
Ethanol (MMBbl)	63.1	66.5	61.2
Liquids leaseable capacity (MMBbl)	81.3	77.8	68.0
Liquids utilization %(e)	93.3%	95.3%	94.7%

Certain item footnotes

(a) 2015 and 2014 amounts include increases in revenues of $23 million and $18 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers. 2013 amount includes an $8 million increase in revenues related to hurricane reimbursements.

(b) In addition to the revenue certain items described in footnote (a) above: 2015 amount includes a $34 million increase in bad debt expense due to certain coal customers bankruptcies related to revenues recognized in prior years but not yet collected and $20 million primarily related to impairment charges. 2014 amount also includes a $29 million write-down associated with a sale of certain terminals to a third-party and $24 million of increased expense from other certain items. 2013 amount also includes (i) a $109 million increase in earnings from casualty indemnification gains; (ii) a $59 million increase in clean-up and repair expense, all related to 2012 hurricane activity at the New York Harbor and Mid-Atlantic terminals; and (iii) a combined $20 million decrease of earnings from other certain items.

(c) An additional $175 million non-cash pre-tax impairment ($84 million net after-tax impact to common stockholders) of a terminal facility reflecting the impact of an agreement to adjust certain payment terms under a contract with a coal customer, which occurred after the issuance of our 2015 fourth quarter earnings release containing our preliminary financial results.

Other footnotes

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

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

Following is information related to the increases and decreases in both EBDA and revenues before certain items in 2015 and 2014, when compared with the respective prior year:
Year Ended December 31, 2015 versus Year Ended December 31, 2014

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Alberta, Canada	$45	70%	$67	102%
Marine Operations	44	n/a	57	n/a
Gulf Liquids	24	11%	41	14%
Gulf Central	23	52%	30	51%
Watco	(17)	(77)%	(57)	(67)%
Gulf Bulk	(16)	(18)%	22	15%
Mid Atlantic	(14)	(21)%	(25)	(18)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(13)	(3)%	21	3%
Total Terminals	$76	8%	$156	9%

n/a – not applicable

The primary changes in the Terminals business segment's EBDA before certain items in the comparable years of 2015 and 2014 included the following:

- increase of $45 million (70%) from our Alberta, Cananda terminals, driven by our recent Edmonton-area expansion projects, including storage and connectivity additions at our Edmonton South and North 40 terminals as well as the commissioning of two joint venture rail terminals;
- increase of $44 million from our Marine Operations related primarily to the incremental earnings from the Jones Act tankers we acquired in the first and fourth quarters of 2014 as well as the December 2015 delivery from the NASSCO shipyard of the first new build tanker, the "Lone Star State;"
- increase of $24 million (11%) from our Gulf Liquids terminals, related to the Vopak terminal acquisition completed in first quarter 2015 and the addition of nine new tanks at Galena Park placed into service during fourth quarter 2014 and first quarter 2015;
- increase of $23 million (52%) from our Gulf Central terminals, driven by higher earnings from our expansion projects at our joint venture terminals, Battleground Oil Specialty Terminal Company LLC (BOSTCO) and Deeprock Development LLC;
- decrease of $17 million (77%) from our sale of certain small bulk and transload terminal facilities to Watco Companies, LLC in early 2015;
- decrease of $16 million (18%) from our Gulf Bulk terminals, primarily from reduced coal earnings due to certain coal customers bankruptcies of $27 million partially offset by increased shortfall revenue from take-or-pay coal contracts;
- decrease of $14 million (21%) from our Mid Atlantic terminals, driven by lower revenues as a result of lower tonnage partially offset by higher shortfall revenue from take-or-pay coal contracts; and
- decrease of $21 million primarily from reduced coal earnings due to certain coal customers bankruptcies, which impacted our International Marine Terminals and Mid River terminals included in "All others" and the Mid Atlantic terminals noted above by $16 million, $3 million and $2 million, respectively.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Acquired assets and businesses	$66	n/a	$109	n/a
Alberta, Canada	32	45%	49	38%
Gulf Central	30	213%	51	663%
Gulf Liquids	20	10%	22	8%
Gulf Bulk	19	25%	26	19%
All others (including intrasegment eliminations and unallocated income tax expenses)	14	3%	41	5%
Total Terminals	$181	23%	$298	21%

n/a – not applicable

The primary changes in the Terminals business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $66 million from acquired assets and businesses, primarily the acquisition of the Jones Act tankers;
- increase of $32 million (45%) from our Alberta, Canada terminals, driven by the completion of Edmonton expansion projects;
- increase of $30 million (213%) from our Gulf Central terminals, driven by higher earnings from our 55% interest in BOSTCO oil terminal joint venture, which is located on the Houston Ship Channel and began operations in October 2013;
- increase of $20 million (10%) from our Gulf Liquids terminals, due to higher liquids warehousing revenues from our Pasadena and Galena Park liquids facilities located along the Houston Ship Channel. The facilities benefited from high gasoline export demand, increased rail services and new and incremental customer agreements at higher rates, due in part to new tankage from completed expansion projects;
- increase of $19 million (25%) from our Gulf Bulk terminals, driven by increased shortfall revenue from take-or-pay coal contracts and higher petcoke period-to-period volumes in 2014, due largely to refinery and coker shutdowns in 2013 as a result of turnarounds taken; and
- increase of $14 million (3%) from the rest of the terminal operations was driven primarily by increased shortfall revenue recognized on take-or-pay contracts at our International Marine Terminal in Myrtle Grove, Louisiana and earnings from the BP Whiting terminal in Whiting, Indiana which was placed in service in the third quarter of 2013.

57

Products Pipelines

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except operating statistics)		
Revenues	$1,831	$2,068	$1,853
Operating expenses	(772)	(1,258)	(1,295)
Other (expense) income	(2)	3	(6)
Earnings from equity investments	45	44	45
Interest income and Other, net	6	1	3
Income tax (expense) benefit	(8)	(2)	2
Segment earnings before DD&A(a)	1,100	856	602
Certain items(a)	(4)	4	182
EBDA before certain items	$1,096	$860	$784
Change from prior period	Increase/(Decrease)		
Revenues	$(237)	$215	
EBDA before certain items	$236	$76	
Gasoline (MMBbl) (b)	377.7	364.7	350.3
Diesel fuel (MMBbl)	131.8	129.1	125.1
Jet fuel (MMBbl)	103.1	100.5	98.6
Total refined product volumes (MMBbl)(c)	612.6	594.3	574.0
NGL (MMBbl)(d)	38.6	25.3	27.7
Condensate (MMBbl)(e)	99.7	33.2	10.7
Total delivery volumes (MMBbl)	750.9	652.8	612.4
Ethanol (MMBbl)(f)	41.4	41.6	38.7

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Certain item footnote

(a) 2015 and 2014 amounts include a $4 million decrease in expense and a $4 million increase in expense, respectively, associated with a certain Pacific operations litigation matter. 2013 amount includes (i) a $162 million increase in expense associated with rate case liability adjustments; (ii) a $15 million increase in expense associated with a legal liability adjustment related to a certain West Coast terminal environmental matter; and (iii) $5 million loss from the write-off of assets at our Los Angeles Harbor West Coast terminal.

Other footnotes

(b) Volumes include ethanol pipeline volumes.

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

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

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

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

Following is information related to the increases and decreases in both EBDA and revenues before certain items in 2015 and 2014, when compared with the respective prior year:

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$102	124%	$90	81%
KMCC - Splitter	33	n/a	43	n/a
Double H pipeline	44	n/a	56	n/a
Cochin	29	34%	54	50%
Pacific operations	23	7%	27	6%
Transmix operations	8	33%	(490)	(49)%
All others (including eliminations)	(3)	(1)%	(17)	(4)%
Total Products Pipelines	$236	27%	$(237)	(12)%

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n/a - not applicable

The primary changes in the Products Pipelines business segment's EBDA before certain items in the comparable years of 2015 and 2014 included the following:

- increase of $102 million (124%) from Kinder Morgan Crude & Condensate Pipeline driven primarily by an increase of pipeline throughput volumes due to the ramp up of existing customer volumes and additional volumes from new customers;
- increase of $33 million from our KMCC - Splitter due to the startup of the first and second phases in March 2015 and July 2015;
- increase of $44 million from our Double H pipeline which was acquired in February 2015 as part of the Hiland acquisition;
- increase of $29 million (34%) from Cochin driven by higher service revenues due to the completion of the Cochin Reversal project in the third quarter of 2014;
- increase of $23 million (7%) from our Pacific operations due to higher service revenues, resulting from higher volumes and margins; and
- increase of $8 million (33%) from our Transmix processing operations primarily due to favorable inventory adjustments impacting margins. The decrease in revenues of $490 million and associated decrease in costs of goods sold were caused by lower commodity prices.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Crude & Condensate Pipeline	$67	320%	$89	402%
Pacific operations	36	13%	25	6%
Transmix operations	(19)	(44)%	92	10%
All others (including eliminations)	(8)	(2)%	9	2%
Total Products Pipelines	$76	10%	$215	12%

The primary changes in the Products Pipelines business segment's EBDA before certain items in the comparable years of 2014 and 2013 included the following:

- increase of $67 million (320%) from Kinder Morgan Crude & Condensate Pipeline, driven primarily by an increase of pipeline throughput volumes to 81.0 MBbl/d as compared to 24.1 MBbl/d in 2013 (236%);

- increase of $36 million (13%) from our Pacific operations, due to higher service revenues driven by higher volumes and margins and lower operating expenses primarily due to lower rights-of-way expenses; and decrease of $19 million (44%) from our transmix processing operations, primarily driven by unfavorable inventory pricing. The increase in revenues of $92 million and associated increase in costs of goods sold were caused by higher product sales volumes.

Kinder Morgan Canada

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except operating statistics)		
Revenues	$260	$291	$302
Operating expenses	(87)	(106)	(110)
Other income	1	—	—
Earnings from equity investments	—	—	4
Interest income and Other, net	8	15	249
Income tax expense	(19)	(18)	(21)
Segment earnings before DD&A(a)	163	182	424
Certain items, net(a)	—	—	(224)
EBDA before certain items	$163	$182	$200
Change from prior period	Increase/(Decrease)		
Revenues	$(31)	$(11)	
EBDA before certain items	$(19)	$(18)	
Transport volumes (MMBbl)(b)	115.4	106.8	101.1

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Certain item footnote

(a) 2013 amount includes a $224 million pre-tax gain from the sale of our equity and debt investments in the Express pipeline system.

Other footnote

(b) Represents Trans Mountain pipeline system volumes.

Following is information related to increases and decreases in both EBDA and revenues before certain items in 2015 and 2014, when compared with the respective prior year:

Year Ended December 31, 2015 versus Year Ended December 31, 2014

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$(12)	(7)%	$(30)	(11)%
Express Pipeline(a)	(7)	(100)%	n/a	n/a
Jet Fuel Pipeline	—	—%	(1)	(17)%
Total Kinder Morgan Canada	$(19)	(10)%	$(31)	(11)%

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n/a - not applicable

(a) Amount consists of unrealized foreign currency gains, net of book tax, on 2014 outstanding, short-term intercompany borrowings that were repaid in December 2014. We sold our debt and equity investments in Express Pipeline on March 14, 2013.

For the comparable years of 2015 and 2014, the Kinder Morgan Canada business segment had a decrease in earnings of $19 million (10%) which was driven primarily by an unfavorable impact from foreign currency exchange rates, and repayment of the Express note as discussed in footnote (a) above.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Express Pipeline(a)	$(6)	(44)%	n/a	n/a
Trans Mountain Pipeline	(12)	(6)%	$(11)	(4)%
Total Kinder Morgan Canada	$(18)	(9)%	$(11)	(4)%

n/a - not applicable

(a) Amount consists of unrealized foreign currency gains, net of book tax, on outstanding, short-term intercompany borrowings that were repaid in December 2014. We sold our debt and equity investments in Express Pipeline on March 14, 2013.

For the comparable years of 2014 and 2013, the Trans Mountain Pipeline had a decrease in earnings of $12 million (6%) which was driven primarily by an unfavorable impact from foreign currency exchange rates. Due to the weakening of the Canadian dollar since the end of the third quarter of 2013, we translated Canadian denominated income and expense amounts into fewer U.S. dollars in 2014.

Other

This segment contributed a loss of $53 million, earnings of $13 million and a loss of $5 million for the years ended 2015, 2014 and 2013, respectively. However, 2015 and 2014 earnings include certain items of a $35 million decrease in earnings and a $22 million increase in earnings, respectively. The 2015 certain items related primarily to a litigation matter and the 2014 certain items were primarily related to our foreign operations. After taking into effect the certain items, the earnings for 2015 and 2014, decreased by $9 million and $4 million, respectively, when compared with the respective prior year.

General and Administrative, Interest, and Noncontrolling Interests

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
General and administrative expense(a)(d)	$690	$610	$613
Certain items(a)	(25)	28	8
Management fee reimbursement(d)	(37)	(36)	(36)
General and administrative expense before certain items	$628	$602	$585
Unallocable interest expense net of interest income and other, net(b)	$2,055	$1,807	$1,688
Certain items(b)	27	3	32
Unallocable interest expense net of interest income and other, net, before certain items	$2,082	$1,810	$1,720
Net (loss) income attributable to noncontrolling interests	$(45)	$1,417	$1,499
Noncontrolling interests associated with certain items(c)	63	—	—
Net income attributable to noncontrolling interests before certain items	$18	$1,417	$1,499

Certain item footnotes

(a) 2015, 2014 and 2013 amounts include decreases in expense of $35 million, $39 million and $59 million related to pension credit income. 2015 amount also includes increases in expense of $45 million related to certain corporate legal matters and $15 million related to costs associated with acquisitions. 2014 amount also includes a net increase of $11 million in expense for various other certain items. 2013 amount also includes increases in expense of $41 million related to asset and business acquisition costs and unallocated legal expenses and a combined $10 million from other certain items primarily related to the acquisition of EP.

(b) 2015, 2014 and 2013 amounts include decreases in interest expense of $71 million, $65 million and $67 million, respectively, related to debt fair value adjustments associated with acquisitions. 2015 and 2014 amounts also include (i) a $23 million increase and $1 million decrease, respectively, in interest expense primarily related to a non-cash true-up of our estimate of swap ineffectiveness; and (ii) a $13 million decrease and $15 million increase, respectively, in interest expense associated with a certain Pacific operations litigation matter.

2015 amount also includes a $34 million increase in interest expense for a non-cash adjustment related to a litigation matter. 2014 and 2013 amounts also include increases in expense of $9 million and $21 million, respectively, of amortization of capitalized financing fees and $12 million and $14 million, respectively, of interest expense on margin for marketing contracts. 2014 amount also includes $27 million of interest expense related to the Merger Transactions.

(c) 2015 amount includes (i) a $43 million impairment recognized after the issuance of our 2015 fourth quarter earnings release containing our preliminary financial results and a $6 million loss associated with Terminals segment certain items and disclosed above in "—Terminals" and (ii) a $14 million loss associated with a Natural Gas Pipelines segment impairment certain item and disclosed above in "—Natural Gas Pipelines."

Other footnote

(d) 2015, 2014 and 2013 amounts include NGPL Holdco LLC general and administrative reimbursements of $37 million, $36 million and $36 million, respectively. 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.

The increase in general and administrative expenses before certain items of $26 million and $17 million in 2015 and 2014 when compared with the respective prior year was primarily driven by the acquisition of Hiland (effective February 13, 2015) and Copano (effective May 1, 2013). Additional drivers for the increase between 2015 and 2014 were lower capitalized costs and higher labor expenses partially offset by lower benefit and insurance costs while the increase between 2014 and 2013 was impacted by higher benefit costs, payroll taxes and labor expenses partially offset by lower costs on our corporate headquarters building and insurance costs.

In the table above, we report our interest expense as "net," meaning that we have subtracted unallocated interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense net of interest income and other, net before certain items, increased $272 million and $90 million in 2015 and 2014, respectively, when compared with the respective prior year. The increase in interest expense in 2015 as compared to 2014 was primarily due to higher average debt balances as a result of capital expenditures, joint venture contributions and acquisitions that were made during 2014 and 2015, and incremental debt borrowings to fund the $3.9 billion cash portion of the Merger Transactions in November 2014.

The increase in interest expense in 2014 as compared to 2013 was primarily due to higher average debt balances as a result of capital expenditures, joint venture contributions and acquisitions that were made during 2014 and incremental debt borrowings to fund the $3.9 billion cash portion of the Merger Transactions in November 2014. In addition, the increase was impacted by the refinancing of the short-term KMI credit facility debt with a $1.5 billion long-term debt issuance in November 2013, which had a higher interest rate. This increase in interest expense was partially offset by (i) lower average balances outstanding on our EP acquisition term loan as a result of its termination in November 2014 and (ii) lower interest rates on our credit facility and EP acquisition term loan as a result of the refinancing of these facilities in 2014.

We use interest rate swap agreements to transform 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 December 31, 2015 and December 31, 2014, approximately 27% and 26%, 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 14 "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 held by us. The $1,399 million decrease (99%)for 2015 as compared to 2014 was primarily due to our purchase of the KMP and EPB limited partner units and KMR shares formerly owned by the public in the fourth quarter of 2014 as part of the Merger

Transactions. The $82 million decrease (5%) for 2014 as compared to 2013 was primarily due to our noncontrolling interests' portion of (i) our 2013 $558 million pre-tax gain from the remeasurement of our previously held 50% equity interest in Eagle Ford to fair value; and (ii) our 2013 $140 million after-tax gain on the sale of our investments in the Express pipeline system; which was partially offset by our noncontrolling interests' portion of our 2014 $198 million pre-tax increase associated with the early termination of a long-term natural gas transportation contract by a certain customer of KMLP and an increase in income allocated to noncontolling interests during the fourth quarter 2014 due to the elimination of the incentive distribution rights as a result of the Merger Transactions.

Subsequent to the Merger Transactions, net income attributable to noncontrolling interests represents net income allocated to third-party ownership interests in consolidated subsidiaries. Prior to the Merger Transactions it also included net income allocated to KMP and EPB limited partner units formerly owned by the public.

Income Taxes—Continuing Operations

Year Ended December 31, 2015 versus Year Ended December 31, 2014

Our income tax expense from continuing operations for the year ended December 31, 2015 was $564 million, as compared with 2014 income tax expense of $648 million. The $84 million decrease in income tax expense is due primarily to (i) the tax impact of lower pretax earnings in 2015 primarily due to our recognition of $929 million of impairments on long-lived assets and investments and $1,150 million goodwill impairment of natural gas pipelines non-regulated midstream assets, of which $882 million is not tax deductible; (ii) the tax benefit of an increase in the deferred state tax rate as a result of the Hiland acquisition; (iii) the 2014 recording of a valuation allowance related to our investment in NGPL; and (iv) the elimination, as a result of the Merger Transactions, of the amortization of the deferred charge recorded as a result of the drop-downs of TGP, EPNG, and the midstream assets. These decreases are partially offset by the 2014 benefit of a worthless stock deduction related to our Brazil operations.

Year Ended December 31, 2014 versus Year Ended December 31, 2013

Our income tax expense from continuing operations for the year ended December 31, 2014 was $648 million, as compared with 2013 income tax expense of $742 million. The $94 million decrease in income tax expense is due primarily to (i) the tax impact of lower pretax earnings in 2014 associated with our investment in KMP primarily related to KMP's 2014 recognition of a $235 million impairment of CO_2 assets compared to gains recognized in 2013 of $558 million on remeasurement to fair value of the initial 50% interest in the Eagle Ford joint venture and $224 million on the sale of the one-third interest in the Express pipeline system; (ii) a 2014 worthless stock deduction related to our Brazil operations; and (iii) a 2013 decrease in our share of non-tax-deductible goodwill associated with our investment in KMP (as a result of our change in ownership primarily due to KMP's acquisition of Copano). These decreases are partially offset by (i) the tax benefit in 2013 of a decrease in the deferred state tax rate as a result of the drop-down of our 50% ownership interest in EPNG and midstream assets and KMP's acquisition of Copano; (ii) 2013 adjustments to our income tax reserve for uncertain tax positions as a result of the settlement of legacy EP Internal Revenue Service audits; and (iii) the 2014 recording of a valuation allowance related to our investment in NGPL.

Liquidity and Capital Resources

General

As of December 31, 2015, we had $229 million of "Cash and cash equivalents," on our consolidated balance sheet, a decrease of $86 million (27%) from December 31, 2014. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in "—Short-term Liquidity"), and our 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 $5,303 million and $4,467 million in 2015 and 2014, respectively (the year-to-year increase of 19% is discussed below in "Cash Flows—Operating Activities"). During 2015, we have relied on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, and dividend payments.

Historically, we have relied on cash from our equity and debt issuances to fund, in large part, expansion capital expenditures, acquisitions and to refinance debt maturities. However, due to the recent unfavorable capital market conditions, the resulting increased cost of equity and debt issuances have made it less economical to do so. As a result, on December 8, 2015, we announced that our board of directors approved a plan pursuant to which we expect to pay quarterly dividends of $0.125 per share to our common shareholders ($0.50 per common share annually), down from our third quarter 2015 dividend of $0.51 per common share, beginning with the fourth quarter 2015 dividend payable to common shareholders on February 16, 2016. We expect the reduced dividend level eliminates our need to access the capital markets to fund our growth projects in 2016.

Additionally, on January 26, 2016, we announced the issuance of a new $1 billion term loan facility and the expansion of our revolving credit facility from $4 billion to $5 billion. The proceeds of the three-year unsecured term loan were used to refinance maturing long-term debt.

Credit Ratings and Capital Market Liquidity

Based on our recent decision to retain a larger portion of our internally generated cash to fund our growth projects, we believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. However, over the long term, we are subject to uncertain capital market conditions and there can be no assurance we will be able or willing to access the public or private markets for equity and/or long-term senior notes in the future. If we were unable or unwilling to access the capital markets, we would be required to either further utilize internally generated cash, restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our and/or our subsidiaries' credit ratings.

Our short-term corporate debt rating is A-3, Prime-3 and F3 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2015.

Rating agency	Senior debt rating	Date of last change	Outlook
Standard and Poor's	BBB-	November 20, 2014	Stable
Moody's Investor Services	Baa3	November 21, 2014	Stable
Fitch Ratings, Inc.	BBB-	November 20, 2014	Stable

Short-term Liquidity

As of December 31, 2015 our principal sources of short-term liquidity are (i) our \$4.0 billion revolving credit facility (which capacity was increased to \$5.0 billion on January 26, 2016) 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 flow from operations.

Our short-term debt as of December 31, 2015 was \$821 million, comprised entirely of the current portion of our long-term debt excluding \$1.0 billion of debt that matured in January and February 2016 that was refinanced using proceeds from the \$1.0 billion term loan issued in January 2016, and therefore included within "Long-term debt" on our consolidated balance sheet at December 31, 2015. We intend to refinance our short-term debt through additional credit facility borrowings, commercial paper borrowings, or with issuing new long-term debt or paying down short-term debt using cash retained from operations. Our combined balance of short-term debt as of December 31, 2014 was \$2,717 million.

We had working capital (defined as current assets less current liabilities) deficits of \$1,241 million and \$2,610 million as of December 31, 2015 and 2014, respectively. Our current liabilities include short-term borrowings used to finance our expansion capital expenditures which periodically we may replace with long-term financing and/or partially pay down using retained cash from operations. The overall \$1,369 million (52%) favorable change from year-end 2014 was primarily due to a net decrease in our credit facility borrowings, commercial paper borrowings and current portion of long-term debt (largely refinanced with the new long-term issuances); offset partially by (i) lower other current assets driven by the 2015 receipt of a federal tax refund; and (ii) lower cash balances. 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 (discussed below in "—Long-term Financing" and "— Capital Expenditures").

We employ a centralized cash management program for our U.S.-based bank accounts that concentrates the cash assets of our subsidiaries, their operating partnerships and their wholly-owned subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. These programs provide that funds in excess of the daily needs of our subsidiaries, their operating partnerships and their wholly-owned subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to parent companies other than restrictions that may be contained in agreements governing the indebtedness of those entities.

Certain of our operating subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Long-term Financing

Our equity consists of Class P common stock and mandatory convertible preferred stock each with a par value of $0.01 per share. In 2015, through an equity distribution agreement, we issued and sold through or to our sales agents and/or principals shares of our Class P common stock. For more information on our equity issuances during 2015 and our equity distribution agreement, see Note 11, "Stockholders' Equity" to our consolidated financial statements.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. In addition, from time to time our subsidiaries, have issued long-term debt securities. Furthermore, we and almost all of our direct and indirect wholly-owned domestic subsidiaries, are parties to a cross guaranty wherein we each guarantee the debt of each other. See Note 19 "Guarantee of Securities of Subsidiaries" to our consolidated financial statements. As of December 31, 2015 and 2014, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $40,732 million and $38,312 million, respectively.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments and through the issuance of commercial paper or credit facility borrowings.

To date, our and our subsidiaries' debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions in 2015, see Note 9 "Debt" to our consolidated financial statements. For information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

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” and “—Preferred Dividends”

Our capital expenditures for the year ended December 31, 2015, and the amount we expect to spend for 2016 to sustain and grow our business are as follows (in millions):

	2015	Expected 2016
Sustaining capital expenditures(a)	$565	$574
Discretionary capital expenditures(b)(c)	$3,532	$3,281

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(a) 2015 and Expected 2016 amounts include $70 million and $90 million, respectively, for our proportionate share of sustaining capital expenditures of certain unconsolidated joint ventures.

(b) 2015 amount includes an increase of $483 million of discretionary capital expenditures of unconsolidated joint ventures and small acquisitions (i.e. excludes Hiland acquisition) and divestitures and a decrease of a combined $352 million of net changes from accrued capital expenditures and contractor retainage.

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

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 13 "Commitments and Contingent Liabilities" to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 7 "Investments" to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
	(In millions)				
Contractual obligations:					
Debt borrowings-principal payments(a)	$41,553	$821	$5,389	$6,772	$28,571
Interest payments(b)	29,311	2,267	4,109	3,610	19,325
Leases and rights-of-way obligations(c)	829	103	173	147	406
Pension and postretirement welfare plans(d)	932	24	34	35	839
Transportation, volume and storage agreements(e)	1,172	160	294	256	462
Other obligations(f)	302	91	95	29	87
Total	$74,099	$3,466	$10,094	$10,849	$49,690
Other commercial commitments:					
Standby letters of credit(g)	$243	$205	$38	$—	$—
Capital expenditures(h)	$1,229	$845	$384	$—	$—

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(a) Less than 1 year amount primarily includes $667 million of current maturities on senior notes and $111 million associated with our Trust I Preferred Securities that are classified as current obligations because these securities have rights to convert into consideration consistent with the EP merger, and excludes $1,000 million of current maturities on long-term debt that were refinanced with proceeds from the issuance of a January 2016 three-year term loan. See Note 9 "Debt" to our consolidated financial statements.

(b) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31, 2015.

(c) Represents commitments pursuant to the terms of operating lease agreements and liabilities for rights-of-way.

(d) Represents the amount by which the benefit obligations exceeded the fair value of fund assets for pension and other postretirement benefit plans at year-end. The payments by period include expected contributions to funded plans in 2016 and estimated benefit payments for unfunded plans in all years.

(e) Primarily represents transportation agreements of $526 million, volume agreements of $454 million and storage agreements for capacity on third party and an affiliate pipeline systems of $135 million.

(f) Primarily includes environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we will perform remediation activities. These liabilities are included within “Other long-term liabilities and deferred credits” in our consolidated balance sheets.

(g) The $243 million in letters of credit outstanding as of December 31, 2015 consisted of the following (i) $73 million under fourteen letters of credit for insurance purposes; (ii) our $30 million guarantee under letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (iii) a $29 million letter of credit supporting our pipeline and terminal operations in Canada; (iv) a $25 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (v) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (vi) an $11 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; and (vii) a combined $35 million in twenty-six letters of credit supporting environmental, power and marketing purposes, and other obligations of us and our subsidiaries.

(h) Represents commitments for the purchase of plant, property and equipment as of December 31, 2015 and obligations for the definitive construction agreement with Philly Tankers LLC for 2016 and 2017.

Cash Flows

Operating Activities

The net increase of $836 million (19%) in cash provided by operating activities in 2015 compared to 2014 was primarily attributable to:

- a $726 million increase in cash associated with net changes in working capital items and non-current assets and liabilities. The increase was driven, among other things, primarily by $347 million of federal and state income tax refunds we received in 2015 of which $195 million was previously reported as an income tax receivable as of December 31, 2014, and higher cash flows due to favorable changes in the collection of trade and exchange gas receivables. These increases were offset by lower cash flow due to the timing of payments from our trade payables;
- a $243 million increase in cash due to the higher payments in 2014 for rate case reserve payments primarily driven by the 2014 CPUC settlement and refund payments; and
- a $133 million decrease in cash from overall net income after adjusting our period-to-period $2,235 million decrease in net income for non-cash items primarily consisting of the following: (i) loss on impairment of goodwill (see discussion above in "—Results of Operations"); (ii) net losses on impairments and disposals of long-lived assets and equity investments (see discussion above in "—Results of Operations"); (iii) DD&A expenses (including amortization of excess cost of equity investments); (iv) deferred income taxes; (v) a net increase in legal reserves (see discussion above in "—Results of Operations"); (vi) an increase in net unrealized gains relating to derivative contracts used to hedge forecasted natural gas, NGL, and crude oil sales (see discussion above in "—Results of Operations"); and (vii) an increase in equity earnings from our equity investments.

Investing Activities

The $496 million net increase in cash used in investing activities in 2015 compared to 2014 was primarily attributable to:

- a $691 million decrease in cash due to higher expenditures for acquisitions and investments. The overall increase in acquisitions was primarily related to the $1,706 million (net of cash acquired and debt assumed) and $158 million we paid for the Hiland and Vopak acquisitions, respectively, in the 2015 period, versus the $1,231 million we paid for the APT and Crowley tankers in 2014. In 2015 we also paid $134 million in cash for our additional 30% interest in NGPL Holdings LLC. See Note 3 "Acquisitions and Divestitures" for further information regarding these acquisitions;
- a $279 million decrease in cash due to higher capital expenditures;
- a $293 million increase in cash due to lower capital contributions to our equity investments, primarily due to a $175 million contribution we made in the third quarter of 2014 to our 50%-owned Midcontinent Express Pipeline LLC to fund our share of its repayment of $350 million in senior notes that matured on September 15, 2014; and
- a $135 million increase in cash in Other, net, primarily due to favorable changes in restricted deposit accounts associated with our hedging activities.

Financing Activities

The net decrease of $144 million in cash provided by financing activities in 2015 compared to 2014 was primarily attributable to:

- a $7,507 million net decrease in cash from overall debt financing activities. See Note 9 “Debt” for further information regarding our debt activity;
- a $2,464 million decrease in cash due to higher total dividend payments;

- a $1,756 million decrease in contributions provided by noncontrolling interests, primarily reflecting the proceeds received from the issuance of KMP's and EPB's common units to the public in the 2014 period and no proceeds in the 2015 period due to the Merger Transactions;
- a $4,009 million increase in cash resulting from the cash portion of consideration for the Merger Transactions and related transaction costs in 2014;
- a $3,870 million increase in cash from the issuances of our Class P shares under our equity distribution agreement;
- a $1,979 million increase in cash due to lower distributions to noncontrolling interests, primarily resulting from our acquisition of the noncontrolling interests associated with KMP and EPB in the Merger Transactions in November 2014;
- a $1,541 million increase in cash from the issuance of our mandatory convertible preferred stock in 2015; and
- a $180 million increase in cash due to the reduction of payments made to repurchase shares and warrants in 2015 compared to the 2014 period.

Common Dividends

The table below reflects the payment of cash dividends of $1.605 per common share for 2015.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2015	$0.48	April 15, 2015	April 30, 2015	May 15, 2015
June 30, 2015	$0.49	July 15, 2015	July 31, 2015	August 14, 2015
September 30, 2015	$0.51	October 21, 2015	November 2, 2015	November 13, 2015
December 31, 2015	$0.125	January 20, 2016	February 1, 2016	February 16, 2016

As disclosed elsewhere in this report, we expect to pay cash dividends totaling $0.50 per share on our common stock for 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." All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common 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 dividends generally will be paid on or about the 16th 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.

On November 17, 2015, our board of directors declared a cash dividend of $23.291667 per share of our mandatory convertible preferred stock (equivalent of $1.164583 per depository share) for the period from and including October 30, 2015 through and including January 25, 2016, was paid on January 26, 2016 to mandatory convertible preferred shareholders of record as of January 11, 2016.

Recent Accounting Pronouncements

Please refer to Note 18 “Recent Accounting Pronouncements” to our consolidated financial statements for information concerning recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in energy commodity prices or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in energy commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we manage these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. The derivative contracts that we use include energy products traded on the NYMEX and OTC markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps. In addition, we have power forward and swap contracts related to legacy operations of acquired businesses for which we entered into positions that offset the price risks associated with these contracts.

Our hedging strategy involves entering into a financial position intended to offset our physical position, or anticipated position, in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative.

Our policies require that derivative contracts are only entered into with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties' credit ratings. While it is our policy to enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future.

The credit ratings of the primary parties from whom we transact in energy commodity derivative contracts (based on contract market values) are as follows (credit ratings per Standard & Poor's Rating Service):

	Credit Rating
Bank of America / Merrill Lynch	BBB+
Societe Generale	A
Macquarie	BBB
J.P. Morgan	A-
J Aron / Goldman Sachs	BBB+

As discussed above, the principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, NGL and crude oil. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but which value is uncertain.

We measure the risk of price changes in the natural gas, NGL, crude oil and power derivative instruments portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. As of December 31, 2015 and 2014, a hypothetical 10% movement in underlying commodity natural gas prices would affect the estimated fair value of natural gas derivatives by $13 million and $9 million, respectively. As of December 31, 2015 and 2014, a hypothetical 10% movement in underlying commodity crude oil prices would affect the estimated fair value of crude oil derivative by $97 million and $146 million, respectively. As of December 31, 2015 and 2014, a hypothetical 10% movement in underlying commodity NGL prices would affect the estimated fair value of our NGL derivatives by $4 million and $0.3 million, respectively. As of both December 31, 2015 and 2014, a hypothetical 10% movement in underlying commodity electricity prices would not affect the estimated fair value of our power derivatives. As discussed above, we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts portfolio is offset largely by changes in the value of the underlying physical transactions.

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the natural gas, NGL, crude oil and power portfolios of derivative contracts assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, interest rate risk and changes in fair value should not have a significant impact on the fixed rate debt until we would be required to refinance such debt.

As of December 31, 2015 and 2014, the carrying values of the fixed rate debt were $43,039 million and $41,390 million, respectively. These amounts compare to, as of December 31, 2015 and 2014, fair values of $37,329 million and $42,343 million, respectively. Fair values were determined using quoted market prices, where applicable, or future cash flow discounted at market rates for similar types of borrowing arrangements. A hypothetical 10% change in the average interest rates applicable to such debt for 2015 and 2014, would result in changes of approximately $1,667 million and $1,539 million, respectively, in the fair values of these instruments.

As of December 31, 2015 and 2014, the carrying values of our variable rate debt were $188 million and $1,424 million, respectively. These amounts compare to, as of December 31, 2015 and 2014, fair values of $152 million and $1,418 million, respectively. As of December 31, 2015 and 2014 we were party to fixed-to-variable interest rate swap agreements with notional principal amounts of $11,000 million and $9,200 million, respectively. A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 49 basis points in 2015 and approximately 50 basis points in 2014) when applied to our outstanding balance of variable rate debt as of December 31, 2015 and 2014, including adjustments for the notional swap amounts described above, would result in changes of approximately $55 million and $53 million, respectively, in our 2015 and 2014 annual pre-tax earnings.

Fixed-to-variable interest rate swap agreements are entered into for the purpose of converting a portion of the underlying cash flows related to long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Since the fair value of fixed rate debt varies with changes in the market rate of interest, swap agreements are entered into to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of the fixed rate debt due to market rate changes.

We monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2015, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 27% of our debt balances were subject to variable interest rates.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 14 “Risk Management” to our consolidated financial statements.

Foreign Currency Risk

In connection with the issuance of our Euro denominated senior notes in March 2015, we entered into $1,358 million of cross-currency swap agreements that effectively convert 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. These swaps eliminate the foreign currency risk associated with our foreign currency denominated debt.

Item 8. Financial Statements and Supplementary Data.

The information required in this Item 8 is in this report as set forth in the “Index to Financial Statements” on page 77.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2015, 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.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

We acquired Hiland in a purchase business acquisition on February 13, 2015. Hiland is a wholly-owned subsidiary and we excluded this business from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015. Hiland total assets and total revenues represent 4% and 3%, respectively, of our related consolidated financial statement amounts as of and for the year ended December 31, 2015.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2016 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2016.

Item 11. Executive Compensation.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2016 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2016.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2016 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2016.

Item 13. Certain Relationships and Related Transactions, and Director Independence.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2016 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2016.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2016 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2016.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements and (2) Financial Statement Schedules
See "Index to Financial Statements" set forth on Page 77.

(3) Exhibits

Exhibit Number		Description
2.1	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan, Inc. (KMI) and P Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.1 to KMI's Current Report on Form 8-K, filed August 12, 2014 (File No. 001-35081))
2.2	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among Kinder Morgan Management, LLC, KMI, and R Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.2 to KMI's Current Report on Form 8-K, filed August 12, 2014 (File No. 001-35081))
2.3	*	Agreement and Plan of Merger, dated as of August 9, 2014, by and among El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., KMI, and E Merger Sub LLC (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K) (filed as Exhibit 2.3 to KMI's Current Report on Form 8-K, filed August 12,

		2014 (File No. 001-35081))
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 as amended by Amendment No. 1 to the Amended and Restated Bylaws (filed as Exhibit 3.1 to KMI’s Current Report on Form 8-K, filed January 26, 2016 (File No. 001-35081))

Exhibit Number		Description
3.3	*	Certificate of Designations of KMI 9.75% Series A Mandatory Convertible Preferred Stock, par value $0.01 per share (KMI Preferred Stock) (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.1	*	Form of certificate representing Class P common shares of KMI (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2	*	Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the three Months ended March 31, 2011 (File No. 001-35081))
4.3	*	Amendment No. 1 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.3 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.4	*	Amendment No. 2 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on December 3, 2014 (File No. 001-35081))
4.5	*	Warrant Agreement, dated as of May 25, 2012, among KMI, Computershare Trust Company, N.A. and Computershare Inc., as Warrant Agent (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.6	*	Form of certificate for KMI Preferred Stock (included as Exhibit A to Exhibit 3.1 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.7	*	Deposit Agreement, dated as of October 30, 2015, between KMI and Computershare Inc. and Computershare Trust Company, N.A., as joint depositary, on behalf of all holders from time to time of the depositary receipts issued thereunder (filed as Exhibit 4.2 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
4.8	*	Form of Depositary Receipt for depositary shares, each representing 1/20th of a share of KMI Preferred Stock (included as Exhibit A to Exhibit 4.2 to KMI's Current Report on Form 8-K filed October 30, 2015 (File No. 001-35081))
10.1	*	KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to KMI's Registration Statement on Form S-8, filed on July 1, 2015, and incorporated herein by reference (File No. 333-205430))
10.2	*	2015 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 4.6 to KMI's Registration Statement on Form S-8, filed on July 1, 2015, and incorporated herein by reference (File No. 333-205430))
10.3	*	2011 Form of Employee Restricted Stock Agreement (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.4	*	Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.5	*	2015 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.6 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))

10.6	*	2011 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.7	*	KMI Employees Stock Purchase Plan (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2011 (File No. 001-35081))
10.8	*	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.4 to KMI's Quarterly Report on Form 10-Q for the three months ended June 30, 2015 (File No. 001-35081))
10.9	*	Form of Senior Indenture between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
10.10	*	Form of Senior Note of Kinder Morgan Kansas, Inc. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
10.11	*	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))

Exhibit Number		Description
10.12	*	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
10.13	*	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))
10.14	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.75% Notes due March 15, 2011 and the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
10.15	*	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))
10.16	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.125% Notes due March 15, 2012 and the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.17	*	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.18	*	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.19	*	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.20	*	Form of 7.30% Notes due 2033 (contained in the Indenture filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.21	*	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.22	*	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.23	*	Certificate of Vice President, Treasurer and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder

		Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))
10.24	*	Certificate of Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))
10.25	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))
10.26	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.95% Senior Notes due 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-11234))

Exhibit Number		Description
10.27	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 9.00% Senior Notes due 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-11234))
10.28	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.625% Senior Notes due 2015, and the 6.85% Senior Notes due 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-11234))
10.29	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))
10.30	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))
10.31	*	Indenture, dated December 20, 2010, among Kinder Morgan Finance Company LLC, Kinder Morgan Kansas, Inc. and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))
10.32	*	Officers' Certificate establishing the terms of the 6.000% Senior Notes due 2018 of Kinder Morgan Finance Company LLC (with the form of note attached thereto) (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 23, 2010 (File No. 1-06446))
10.33	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2016, and the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234))
10.34	*	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))
10.35	*	Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q

		for the quarter ended March 31, 2014 (File No. 1-11234))
10.36	*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (Filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234))
10.37	*	Certificate of the Vice President and Treasurer and the Vice President and Secretary of KMI establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045 (filed as Exhibit 10.53 to KMI's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-35081))
10.38	*	Certificate of Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 5.050% Senior Notes due 2046 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the three months ended March 31, 2015 (File No. 001-35081))
10.39	*	Certificate of Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 1.500% Senior Notes due 2022 and 2.250% Senior Notes due 2027 (filed as Exhibit 4.2 to KMI's Form 8-A, filed March 16, 2015 and incorporated herein by reference (File No. 001-35081))

Exhibit Number		Description
10.40	*	Support Agreement, dated as of August 9, 2014, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Richard D. Kinder and RDK Investments, Ltd. (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed August 12, 2014 (File No. 001-35081))
10.41	*	Bridge Credit Agreement, dated September 19, 2014 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed September 25, 2014 (File No. 001-35081))
10.42	*	Revolving Credit Agreement, dated September 19, 2014 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed September 25, 2014(File No. 001-35081))
10.43		Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2015
12.1		Statement re: computation of ratio of earnings to fixed charges
21.1		Subsidiaries of KMI
23.1		Consent of PricewaterhouseCoopers LLP
23.2		Consent of Netherland, Sewell & Associates, Inc.
31.1		Certification of 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 of 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 of 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 of 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
99.1		Netherland, Sewell & Associates, Inc.'s report of estimates of the net reserves and future net revenues, as of December 31, 2015, related to Kinder Morgan CO_2 Company, L.P.'s interest in certain oil and gas properties located in the state of Texas
101		Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2015, 2014, and 2013; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2015, 2014, and 2013; (iii) our Consolidated Balance Sheets as of December 31, 2015 and 2014; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014, and 2013; (v) our Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2015, 2014, and 2013; and (vi) the notes to our

Consolidated Financial Statements

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

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

	Page Number
Report of Independent Registered Public Accounting Firm	78
Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013	79
Consolidated Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013	81
Consolidated Balance Sheets as of December 31, 2015 and 2014	82
Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013	83
Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2015, 2014 and 2013	85
Notes to Consolidated Financial Statements	86

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Kinder Morgan, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of stockholders’ equity and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan, Inc. and its subsidiaries (the “Company”) at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing in Item 9A of the Company’s 2015 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management’s Report on Internal Control over Financial Reporting appearing in Item 9A of the Company’s 2015 Annual Report on Form 10- K, management has excluded Hiland Partners, LP from its assessment of internal control over financial reporting as of December 31, 2015 because it was acquired in a purchase business combination by Kinder Morgan, Inc. on February 13, 2015. We have also excluded Hiland Partners, LP from our audit of internal control over financial reporting. Hiland Partners, LP is a wholly-owned subsidiary whose total assets and total revenues represent 4% and 3%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2015.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 16, 2016

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

	Year Ended December 31,		
	2015	2014	2013
Revenues			
Natural gas sales	$2,839	$4,115	$3,605
Services	8,290	7,650	6,677
Product sales and other	3,274	4,461	3,788
Total Revenues	14,403	16,226	14,070
Operating Costs, Expenses and Other			
Costs of sales	4,115	6,278	5,253
Operations and maintenance	2,337	2,157	2,112
Depreciation, depletion and amortization	2,309	2,040	1,806
General and administrative	690	610	613
Taxes, other than income taxes	439	418	395
Loss on impairment of goodwill	1,150	—	—
Loss (gain) on impairments and disposals of long-lived assets, net	919	274	(98)
Other (income) expense, net	(3)	1	(1)
Total Operating Costs, Expenses and Other	11,956	11,778	10,080
Operating Income	2,447	4,448	3,990
Other Income (Expense)			
Earnings from equity investments	414	406	392
Loss on impairments of equity investments	(30)	—	(65)
Amortization of excess cost of equity investments	(51)	(45)	(39)
Interest, net	(2,051)	(1,798)	(1,675)
Gain on remeasurement of previously held equity investments to fair value (Note 3)	—	—	558
Gain on sale of investments in Express pipeline system (Note 3)	—	—	224
Other, net	43	80	53
Total Other Expense	(1,675)	(1,357)	(552)
Income from Continuing Operations Before Income Taxes	772	3,091	3,438
Income Tax Expense	(564)	(648)	(742)
Income from Continuing Operations	208	2,443	2,696
Discontinued Operations			
Loss on sale of the FTC Natural Gas Pipelines disposal group, net of tax	—	—	(4)
Net Income	208	2,443	2,692
Net Loss (Income) Attributable to Noncontrolling Interests	45	(1,417)	(1,499)
Net Income Attributable to Kinder Morgan, Inc.	253	1,026	1,193

Preferred Stock Dividends	(26)	—	—
Net Income Available to Common Stockholders	$227	$1,026	$1,193

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

	Year Ended December 31,		
	2015	2014	2013
Class P Shares			
Basic Earnings Per Common Share	$0.10	$0.89	$1.15
Basic Weighted Average Common Shares Outstanding	2,187	1,137	1,036
Diluted Earnings Per Common Share	$0.10	$0.89	$1.15
Diluted Weighted Average Common Shares Outstanding	2,193	1,137	1,036
Dividends Per Common Share Declared for the Period	$1.605	$1.740	$1.600

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

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

	Year Ended December 31,		
	2015	2014	2013
Net income	$208	$2,443	$2,692
Other comprehensive income (loss), net of tax			
Change in fair value of hedge derivatives (net of tax (expense) benefit of $(94), $(163) and $10, respectively)	164	409	(38)
Reclassification of change in fair value of derivatives to net income (net of tax benefit (expense) of $156, $13 and $(3), respectively)	(272)	(25)	11
Foreign currency translation adjustments (net of tax benefit of $123, $48, and $31, respectively)	(214)	(138)	(103)
Benefit plan adjustments (net of tax benefit (expense) of $69, $126 and $(91), respectively)	(122)	(226)	170
Total other comprehensive (loss) income	(444)	20	40
Comprehensive (loss) income	(236)	2,463	2,732
Comprehensive loss (income) attributable to noncontrolling interests	45	(1,486)	(1,445)
Comprehensive (loss) income attributable to KMI	$(191)	$977	$1,287

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

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

	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$229	$315
Accounts receivable, net	1,315	1,641
Fair value of derivative contracts	507	535
Inventories	407	459
Deferred income taxes	—	56
Other current assets	366	746
Total current assets	2,824	3,752
Property, plant and equipment, net	40,547	38,564
Investments	6,040	6,036
Goodwill	23,790	24,654
Other intangibles, net	3,551	2,302
Deferred income taxes	5,323	5,651
Deferred charges and other assets	2,029	2,090
Total Assets	$84,104	$83,049
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$821	$2,717
Accounts payable	1,324	1,588
Accrued interest	695	637
Accrued contingencies	298	383
Other current liabilities	927	1,037
Total current liabilities	4,065	6,362
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	40,632	38,212
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,674	1,785
Total long-term debt	42,406	40,097
Other long-term liabilities and deferred credits	2,230	2,164
Total long-term liabilities and deferred credits	44,636	42,261
Total Liabilities	48,701	48,623
Commitments and contingencies (Notes 9, 13 and 17)		
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,229,223,864 and 2,125,147,116 shares, respectively, issued and outstanding	22	21
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	41,661	36,178

Retained deficit	(6,103)	(2,106)
Accumulated other comprehensive loss	(461)	(17)
Total Kinder Morgan, Inc.'s stockholders' equity	35,119	34,076
Noncontrolling interests	284	350
Total Stockholders' Equity	35,403	34,426
Total Liabilities and Stockholders' Equity	$84,104	$83,049

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

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

	Year Ended December 31,		
	2015	2014	2013
Cash Flows From Operating Activities			
Net income	$208	$2,443	$2,692
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,309	2,040	1,806
Deferred income taxes	692	615	640
Amortization of excess cost of equity investments	51	45	39
Loss on impairment of goodwill (Note 4)	1,150	—	—
Loss (gain) on impairments and disposals of long-lived assets and equity investments, net	949	274	(33)
Gain from the remeasurement of net assets to fair value and the sale of discontinued operations (net of cash selling expenses), net of tax (Note 3)	—	—	(556)
Gain from sale of investments in Express pipeline system (Note 3)	—	—	(224)
Earnings from equity investments	(414)	(406)	(392)
Distributions of equity investment earnings	391	381	398
Proceeds from termination of interest rate swap agreements	—	—	96
Pension contributions and noncash pension benefit credits	(85)	(88)	(120)
Changes in components of working capital, net of the effects of acquisitions			
Accounts receivable	382	(84)	(131)
Income tax receivable	195	(195)	—
Inventories	34	(30)	(53)
Other current assets	113	(17)	(32)
Accounts payable	(156)	(1)	(36)
Accrued interest, net of interest rate swaps	37	61	50
Accrued contingencies and other current liabilities	(129)	108	(100)
Rate reparations, refunds and other litigation reserve adjustments	18	(280)	174
Other, net	(442)	(399)	(96)
Net Cash Provided by Operating Activities	5,303	4,467	4,122
Cash Flows From Investing Activities			
Acquisitions of assets and investments, net of cash acquired	(2,079)	(1,388)	(292)
Proceeds from sales of assets and investments	—	—	490
Capital expenditures	(3,896)	(3,617)	(3,369)
Contributions to investments	(96)	(389)	(217)
Distributions from equity investments in excess of cumulative earnings	228	182	185
Other, net	137	2	81
Net Cash Used in Investing Activities	(5,706)	(5,210)	(3,122)
Cash Flows From Financing Activities			
Issuances of debt	14,316	24,573	13,581
Payments of debt	(15,116)	(17,801)	(12,393)
Debt issue costs	(24)	(89)	(38)
Issuances of common shares (Note 11)	3,870	—	—

Issuance of mandatory convertible preferred stock (Note 11)	1,541	—	—
Cash dividends (Note 11)	(4,224)	(1,760)	(1,622)
Repurchases of shares and warrants	(12)	(192)	(637)
Cash consideration of Merger Transactions (Note 1)	—	(3,937)	—
Merger Transactions costs	(2)	(74)	—
Contributions from noncontrolling interests	11	1,767	1,706
Distributions to noncontrolling interests	(34)	(2,013)	(1,692)
Other, net	1	(3)	—
Net Cash Provided by (Used in) Financing Activities	327	471	(1,095)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(10)	(11)	(21)
Net decrease in Cash and Cash Equivalents	(86)	(283)	(116)
Cash and Cash Equivalents, beginning of period	315	598	714
Cash and Cash Equivalents, end of period	$229	$315	$598

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

	Year Ended December 31,		
	2015	2014	2013
Noncash Investing and Financing Activities			
Assets acquired by the assumption or incurrence of liabilities	$1,681	$106	$1,510
Net assets contributed to equity investment	46	—	—
Net assets and liabilities or noncontrolling interests acquired by the issuance of shares and warrants (Notes 1 and 3)	—	16,023	—
Assets acquired or liabilities settled by contributions from noncontrolling interests	—	—	3,733
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,985	1,718	1,652
Cash (refund) paid during the period for income taxes, net	(331)	227	67

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

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

	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, 2012	1,036	$10	—	$—	$14,917	$(943)	$(118)	$13,866	$ 10,234	$24,100
Repurchases of shares and warrants	(5)				(637)			(637)		(637)
Warrants exercised					1			1		1
EP Trust I Preferred security conversions					3			3		3
Restricted shares					33			33		33
Impact from equity transactions of KMP, EPB and KMR					161			161	(254)	(93)
Net income						1,193		1,193	1,499	2,692
Distributions								—	(1,692)	(1,692)
Contributions								—	5,439	5,439
KMP's acquisition of Copano noncontrolling interests								—	17	17
Common stock dividends						(1,622)		(1,622)		(1,622)
Other					1			1	3	4
Other comprehensive income							94	94	(54)	40
Balance at December 31, 2013	1,031	10	—	—	14,479	(1,372)	(24)	13,093	15,192	28,285
Impact of Merger Transactions	1,097	11			21,880			21,891	(15,936)	5,955
Merger Transactions costs					(75)			(75)		(75)
Repurchases of shares and warrants	(3)				(192)			(192)		(192)
Restricted shares					52			52		52
Impact from equity transactions of KMP, EPB and KMR					36			36	(55)	(19)
Net income						1,026		1,026	1,417	2,443
Distributions								—	(2,013)	(2,013)
Contributions								—	1,767	1,767
Common stock dividends						(1,760)		(1,760)		(1,760)
Other					(2)			(2)	(4)	(6)
Other comprehensive (loss) income							(49)	(49)	69	20
Impact of Merger Transactions on Accumulated other comprehensive loss							56	56	(87)	(31)
Balance at December 31, 2014	2,125	21	—	—	36,178	(2,106)	(17)	34,076	350	34,426
Issuances of common shares	103	1			3,869			3,870		3,870
Issuances of preferred shares			2		1,541			1,541		1,541
Repurchases of warrants					(12)			(12)		(12)
EP Trust I Preferred security conversions	1				23			23		23

Warrants exercised					2			2		2
Restricted shares					57			57		57
Net income						253		253	(45)	208
Distributions								—	(34)	(34)
Contributions								—	11	11
Preferred stock dividends						(26)		(26)		(26)
Common stock dividends						(4,224)		(4,224)		(4,224)
Other					3			3	2	5
Other comprehensive loss							(444)	(444)		(444)
Balance at December 31, 2015	2,229	$22	2	$—	$41,661	$(6,103)	$(461)	$35,119	$ 284	$35,403

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

KINDER MORGAN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are the largest energy infrastructure company in North America and unless the context requires otherwise, references to “we,” “us,” “our,” “the Company,” or “KMI” are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. 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.

On November 26, 2014, we completed our acquisition, pursuant to three separate merger agreements, of all of the outstanding common units of Kinder Morgan Energy Partners, L.P. and El Paso Pipeline Partners, L.P. and all of the outstanding shares of Kinder Morgan Management, LLC that we did not already own. The transactions, valued at approximately $77 billion, are referred to collectively as the “Merger Transactions.”

As we controlled each of KMP, KMR and EPB and continued to control each of them after the Merger Transactions, the changes in our ownership interest in each of KMP, KMR and EPB were accounted for as an equity transaction and no gain or loss was recognized in our consolidated statements of income related to the Merger Transactions. After closing the KMR Merger Transaction, KMR was merged with and into KMI. On January 1, 2015, EPB and its subsidiary, EPPOC merged with and into KMP. References to EPB refer to EPB for periods prior to its merger into KMP.

Prior to the Merger Transactions, we owned an approximate 10% limited partner interest (including our interest in KMR) and the 2% general partner interest including incentive distribution rights in KMP, and an approximate 39% limited partner interest and the 2% general partner interest and incentive distribution rights in EPB. Effective with the Merger Transactions, the incentive distribution rights held by the general partner of KMP was eliminated.

The equity interests in KMP, EPB and KMR (which are all consolidated in our financial statements) owned by the public prior to the Merger Transactions are reflected within “Noncontrolling interests” in our accompanying consolidated statements of stockholders’ equity. The earnings recorded by KMP, EPB and KMR that are attributed to their units and shares, respectively, held by the public prior to the Merger Transactions are reported as “Net income attributable to noncontrolling interests” in our accompanying consolidated statements of income.

Our common stock trades on the NYSE under the symbol “KMI.”

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, except where stated otherwise. Our accompanying consolidated financial statements have been prepared under the rules and regulations of the 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. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In addition, we believe that certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Deposits

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Restricted cash of $60 million and $118 million as of December 31, 2015 and 2014, respectively, is included in “Other current assets.”

Accounts Receivable, net

The amounts reported as “Accounts receivable, net” on our accompanying consolidated balance sheets as of December 31, 2015 and 2014 primarily consist of amounts due from customers.

Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. Generally, we make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and we record adjustments as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved.

The allowance for doubtful accounts was $91 million and $10 million as of December 31, 2015 and 2014, respectively. The increase was primarily associated with reserves established related to certain coal customers.

Inventories

Our inventories consist of materials and supplies and products such as, NGL, crude oil, condensate, refined petroleum products, transmix and natural gas. We report these assets at the lower of weighted-average cost or market. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Gas Imbalances

We value gas imbalances due to or due from interconnecting pipelines at market prices. As of December 31, 2015 and 2014, our gas imbalance receivables—including both trade and related party receivables—totaled $21 million and $103 million, respectively, and we included these amounts within “Other current assets” on our accompanying consolidated balance sheets. As of December 31, 2015 and 2014, our gas imbalance payables—consisting of only trade payables—totaled $17 million and $36 million, respectively, and we included these amounts within “Other current liabilities” on our accompanying consolidated balance sheets.

Property, Plant and Equipment, net

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for routine maintenance and repairs in the period incurred.

We generally compute depreciation using either the straight-line method based on estimated economic lives or, for certain depreciable assets, we employ the composite depreciation method, applying a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 0.9% to 23.0% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances, contract term for assets on leased or customer property and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs. The units-of-production depreciation rate is determined by field and for our oil and gas producing fields that have no proved reserves, the units-of-production depreciation rate is based on each field’s probable reserves and NYMEX forward curve prices.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our bulk and liquids terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the market value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset. For our pipeline system assets under the composite method of depreciation, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. Gains and losses are booked for operating unit sales and land sales and are recorded to income or expense accounts in accordance with regulatory accounting guidelines. In those instances where we receive recovery in tariff rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

Long-lived Asset Impairments

We evaluate long-lived assets and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

Prior to us conducting the goodwill impairment test, to the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable reserves. For the purpose of impairment testing, adjustments for the inclusion of risk-adjusted probable reserves, as well as forward curve pricing and estimates of future costs, will cause impairment calculation cash flows to differ from the amounts presented in our supplemental information on oil and gas producing activities disclosed in "Supplemental Information on Oil and Gas Producing Activities (Unaudited)."

Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Equity Method of Accounting and Excess Investment Cost

We account for investments—which we do not control, but do have the ability to exercise significant influence—by the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received.

With regard to our equity investments in unconsolidated affiliates, in almost all cases, either (i) the price we paid to acquire our share of the net assets of such equity investees or (ii) the revaluation of our share of the net assets of any retained noncontrolling equity investment (from the sale of a portion of our ownership interest in a consolidated subsidiary, thereby losing our controlling financial interest in the subsidiary) differed from the underlying carrying value of such net assets. This differential consists of two pieces. First, an amount related to the difference between the investee's recognized net assets at book value and at current fair values (representing the appreciated value in plant and other net assets), and secondly, to any premium in excess of fair value (referred to as equity method goodwill) we paid to acquire the investment. We include both amounts within "Investments" on our accompanying consolidated balance sheets.

The first differential, representing the excess of the fair market value of our investees' plant and other net assets over its underlying book value at either the date of acquisition or the date of the loss of control totaled $808 million and $870 million as of December 31, 2015 and 2014, respectively. Generally, this basis difference relates to our share of the underlying depreciable assets, and, as such, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2015, this excess investment cost is being amortized over a weighted average life of approximately fifteen years.

The second differential, representing equity method goodwill, totaled $138 million as of both December 31, 2015 and 2014. This differential is not subject to amortization but rather to impairment testing as part of our periodic evaluation of the recoverability of our investment as compared to the fair value of net assets accounted for under the equity method. Our impairment test considers whether the fair value of the equity investment as a whole has declined and whether that decline is other than temporary.

Goodwill

Goodwill is the cost of an acquisition in excess of the fair value of acquired assets and liabilities and is recorded as an asset on our balance sheet. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have seven reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO_2; (vi) Terminals; and (vii) Kinder Morgan Canada. We also evaluate goodwill for impairment to the extent events or conditions indicate a risk of possible impairment during the interim periods subsequent to our annual impairment test. Generally, the evaluation of goodwill for impairment involves a two-step test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

Step 1 involves comparing the estimated fair value of each respective reporting unit to its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, the reporting unit's goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, step 2 must be performed to determine whether goodwill is impaired and, if so, the amount of the impairment. Step 2 involves calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill is then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeds the implied goodwill, the difference is the amount of the goodwill impairment.

A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

Refer to Note 8 for further information.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. As of December 31, 2015 and 2014, these intangible assets totaled $3,551 million and $2,302 million, respectively, and primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

Primarily, these contracts, relationships and agreements relate to the gathering of natural gas, and the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, coal, petroleum coke, fertilizer, steel and ores. We determined the values of these intangible assets by first, estimating the revenues derived from a customer contract or relationship (offset by the cost and expenses of supporting assets to fulfill the contract), and second, discounting the revenues at a risk adjusted discount rate.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. The life of each intangible asset is based either on the life of the corresponding customer contract or agreement or, in the case of a customer relationship intangible (the life of which was determined by an analysis of all available data on that business relationship), the length of time used in the discounted cash flow analysis to determine the value of the customer relationship. Among the factors we weigh, depending on the nature of the asset, are the effect of obsolescence, new technology, and competition.

For the years ended December 31, 2015, 2014 and 2013, the amortization expense on our intangibles totaled $221 million, $143 million and $125 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2016 – 2020) is approximately $221 million, $218 million, $216 million, $214 million, and $211 million , respectively. As of December 31, 2015, the weighted average amortization period for our intangible assets was approximately eighteen years.

Other intangibles are evaluated for recoverability consistent with the discussion above on long-lived asset impairments.

Revenue Recognition

We recognize revenue as services are rendered or goods are delivered and, if applicable, risk of loss has passed. We recognize natural gas, crude and NGL sales revenue when the commodity is sold to a purchaser at a fixed or determinable price, delivery has occurred and risk of loss has transferred, and collectability of the revenue is reasonably assured. Our sales and purchases of natural gas, crude and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales, except in circumstances where we soley act as an agent and do not have price and related risk of ownership, in which case we recognize revenue on a net basis.

In addition to storing and transporting a significant portion of the natural gas volumes we purchase and resell, we provide various types of natural gas storage and transportation services for third-party customers. Under these contracts, the natural gas remains the property of these customers at all times. In many cases, generally described as firm service, the customer pays a two-part rate that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers' agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities.

In other cases, generally described as interruptible service, there is no fixed fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements.

We provide crude oil and refined petroleum products transportation and storage services to customers. Revenues are recorded when products are delivered and services have been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognize bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognize liquids terminal tank rental revenue ratably over the contract period. We recognize liquids terminal throughput revenue based on volumes received and volumes delivered. We recognize transmix processing revenues based on volumes processed or sold, and if applicable, when risk of loss has passed. We recognize energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of crude oil, NGL, CO_2 and natural gas production within the CO_2 business segment are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on our net interest. We record our entitled share of revenues based on entitled volumes and contracted sales prices. Since there is a ready market for oil and gas production, we sell the majority of our products soon after production at various locations, at which time title and risk of loss pass to the buyer.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining rights-of-way, regulatory approvals or permitting as part of the construction. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable.

Pensions and Other Postretirement Benefits

We recognize the differences between the fair value of each of our and our consolidated subsidiaries' pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—in "Accumulated other comprehensive loss" or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense.

Noncontrolling Interests

Noncontrolling interests represents the interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income (or loss) of our consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as “Net Income Attributable to Noncontrolling Interests." In our accompanying consolidated balance sheets, noncontrolling interests is presented separately as "Noncontrolling interests" within "Stockholders' Equity."

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit we do not expect to be realized.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments.

Foreign Currency Transactions and Translation

Foreign currency transaction gains or losses result from a change in exchange rates between (i) the functional currency, for example the Canadian dollar for a Canadian subsidiary and (ii) the currency in which a foreign currency transaction is denominated, for example the U.S. dollar for a Canadian subsidiary. In our accompanying consolidated statements of income, gains and losses from our foreign currency transactions are included within "Other Income (Expense)—Other, net."

Foreign currency translation is the process of expressing, in U.S. dollars, amounts recorded in a local functional currency other than U.S. dollars, for example the Canadian dollar for a Canadian subsidiary. We translate the assets and liabilities of each of our consolidated foreign subsidiaries that have a local functional currency to U.S. dollars at year-end exchange rates. Income and expense items are translated at weighted-average rates of exchange prevailing during the year and stockholders' equity accounts are translated by using historical exchange rates. The cumulative translation adjustments balance is reported as a component of "Accumulated other comprehensive loss."

Comprehensive Income

For each of the years ended December 31, 2015, 2014 and 2013, the difference between our net income and our comprehensive income resulted from (i) unrealized gains or losses on derivative contracts accounted for as cash flow hedges; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other postretirement benefit plan liabilities. For more information on our risk management activities, see Note 14.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of commodities including natural gas, NGL and crude oil. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. For certain physical forward commodity derivatives contracts, we apply the normal purchase/normal sale exception, whereby the revenues and expenses associated with such transactions are recognized during the period when the commodities are physically delivered or received.

For qualifying accounting hedges, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing effectiveness, and how any ineffectiveness will be measured and recorded. If we designate a derivative contract as a cash flow accounting hedge, the effective portion of the change in fair value of the derivative is deferred in accumulated other comprehensive income/(loss) and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative’s change in fair value or amount excluded from the assessment of hedge effectiveness is recognized currently in earnings. If we designate a derivative contract as a fair value accounting hedge, the effective portion of the change in fair value of the derivative is recorded as an adjustment to the item being hedged. Any ineffective portion of the derivative’s change in fair value is recognized currently in earnings.

For derivative instruments that are not designated as accounting hedges, or for which we have not elected the normal purchase/normal sales exception, changes in fair value are recognized currently in earnings.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We included the amounts of our regulatory assets and liabilities within "Other current assets," "Deferred charges and other assets," "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets. As of December 31, 2015, the recovery period for these regulatory assets was approximately one year to forty-one years.

The following table summarizes our regulatory asset and liability balances as of December 31, 2015 and 2014 (in millions):

	December 31,	
	2015	2014
Current regulatory assets	$55	$81
Non-current regulatory assets	378	406
Total regulatory assets	$433	$487
Current regulatory liabilities	$161	$189
Non-current regulatory liabilities	166	290
Total regulatory liabilities	$327	$479

Transfer of Net Assets Between Entities Under Common Control

We account for the transfer of net assets between entities under common control by carrying forward the net assets recognized in the balance sheets of each combining entity to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination. Transfers of net assets between entities under common control do not affect the historical income statement or balance sheet of the combined entity.

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):

	Year Ended December 31,		
	2015	2014	2013
Class P	$214	$1,015	$1,187
Participating securities:			
Restricted stock awards(a)	13	11	6
Net Income Available to Common Stockholders	$227	$1,026	$1,193

	Year Ended December 31,		
	2015	2014	2013
Basic Weighted Average Common Shares Outstanding	2,187	1,137	1,036
Effect of dilutive securities:			
Warrants(b)	6	—	—
Diluted Weighted Average Common Shares Outstanding	2,193	1,137	1,036

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(a) As of December 31, 2015, there were approximately 8 million such restricted stock awards.

(b) 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 following 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):

	Year Ended December 31,		
	2015	2014	2013
Unvested restricted stock awards	7	7	4
Warrants to purchase our Class P shares	291	312	401
Convertible trust preferred securities	8	10	10
Mandatory convertible preferred stock	10	n/a	n/a

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n/a - not applicable

3. Acquisitions and Divestitures

Business Combinations

During 2015, 2014 and 2013, we completed the following significant acquisitions accounted for in accordance with the "Business Combinations" Topic of the Codification.

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. Additionally, we adjust goodwill as a result of applying the look-through method of recording deferred taxes on the outside book tax basis differences in our investments without regard to non-tax deductible goodwill.

The following table discloses our assignment of the purchase price for each of our significant acquisitions (in millions):

			Assignment of Purchase Price								
Ref.	Date	Acquisition	Purchase price	Current assets	Property plant & equipment	Deferred charges & other	Goodwill	Long-term debt	Other liabilities	Non-controlling interest	Previously held equity interest
(1)	2/15	Vopak Terminal Assets	$ 158	$ 2	$ 155	$ —	$ 7	$ —	$ (6)	$ —	$ —
(2)	2/15	Hiland	1,709	79	1,497	1,498	310	(1,411)	(264)	—	—
(3)	11/14	Pennsylvania and Florida Jones Act Tankers	270	—	270	8	25	—	(33)	—	—
(4)	1/14	American Petroleum Tankers and State Class Tankers	961	6	951	6	64	—	(66)	—	—
(5)	6/13	Goldsmith-Landreth Field Unit	280	—	298	—	—	—	(18)	—	—
(6)	5/13	Copano	3,733	218	2,788	1,973	963	(1,252)	(236)	(17)	(704)

(1) Vopak Terminal Assets

On February 27, 2015, we acquired three U.S. terminals and one undeveloped site from Royal Vopak (Vopak) for approximately $158 million in cash. The acquisition included (i) a 36-acre, 1,069,500-barrel storage facility at Galena Park, Texas that handles base oils, biodiesel and crude oil and is immediately adjacent to our Galena Park terminal facility; (ii) two terminals in North Carolina: one in North Wilmington that handles chemicals and black oil and the other in South Wilmington that is not currently operating; and (iii) an undeveloped waterfront access site in Perth Amboy, New Jersey. We include the acquired assets as part of the Terminals business segment.

(2) Hiland

On February 13, 2015, we acquired Hiland, a privately held Delaware limited partnership for aggregate consideration of approximately $3,120 million, including assumed debt. Approximately $368 million of the debt assumed was immediately paid down after closing. Hiland's assets consist primarily of crude oil gathering and transportation pipelines and gas gathering and processing systems, primarily handling production from the Bakken Formation in North Dakota and Montana. The acquired gathering and processing assets are included in our Natural Gas Pipelines business segment while the acquired crude oil transport pipeline (Double H pipeline) is included in our Products Pipelines business segment. Deferred charges and other relates to customer contracts and relationships with a weighted average amortization period of 16.8 years.

(3) Pennsylvania and Florida Jones Act Tankers

On November 5, 2014, we acquired two Jones Act tankers from Crowley Maritime Corporation (Crowley) for approximately $270 million. The MT Pennsylvania and the MT Florida engage in the marine transportation of crude oil, condensate and refined products in the U.S. domestic trade, commonly referred to as the Jones Act trade, and are currently operating pursuant to multi-year charters with a major integrated oil company. The vessels each have approximately 330 MBbl of cargo capacity and are included in the Terminals business segment. The acquired vessels will continue to be operated by Crowley.

(4) American Petroleum Tankers and State Class Tankers

Effective January 17, 2014, we acquired APT and State Class Tankers (SCT) for aggregate consideration of $961 million in cash (the APT acquisition). APT is engaged in Jones Act trade and its primary assets consist of a fleet of five medium range Jones Act qualified product tankers, each with 330 MBbl of cargo capacity, and each operating pursuant to long-term time charters with high quality counterparties, including major integrated oil companies, major refiners and the U.S. Military Sealift Command. As of the closing date, the vessels' time charters had an average remaining term of approximately four years, with renewal options to extend the terms by an average of two years. APT's vessels are operated by Crowley.

SCT commissioned the construction of four medium range Jones Act qualified product tankers, by General Dynamics' NASSCO shipyard, each with 330 MBbl of cargo capacity and delivery dates in 2015 and 2016. The time charters for each vessel upon completion has an initial term of five years, with renewal options to extend the term by up to three years. The APT acquisition complements and extends our existing crude oil and refined products transportation and storage business. We include the acquired assets as part of the Terminals business segment.

(5) Goldsmith Landreth Field Unit

On June 1, 2013, we acquired certain oil and gas properties, rights, and related assets in the Permian Basin of West Texas from Legado Resources LLC for an aggregate consideration of $298 million consisting of $280 million in cash and assumed liabilities of $18 million (including $12 million of long-term asset retirement obligations). The acquisition of the Goldsmith Landreth San Andres oil field unit includes more than 6,000 acres located in Ector County, Texas. The acquired oil field is in the early stages of CO_2 flood development and includes a residual oil zone along with a classic San Andres waterflood. As part of the transaction, we obtained a long-term supply contract for up to 150 MMcf/d of CO_2. The acquisition complemented our existing oil and gas producing assets in the Permian Basin, and we included the acquired assets as part of the CO_2 business segment.

(6) Copano

Effective May 1, 2013, we acquired all of Copano's outstanding units for a total purchase price of approximately $5.2 billion (including assumed debt and all other assumed liabilities). The transaction was a 100% unit for unit transaction with an exchange ratio of 0.4563 of KMP's common units for each Copano common unit. Due to the fact that our acquisition included the remaining 50% interest in Eagle Ford that we did not already own, we remeasured the carrying value ($146 million) of our existing 50% equity investment in Eagle Ford to its fair value ($704 million) as of the May 1, 2013 acquisition date. As a result of this remeasurement, we recognized a $558 million non-cash gain and we reported this gain within "Gain on remeasurement of previously held equity investments to fair value" in our accompanying consolidated statement of income for the year ended December 31, 2013.

Pro Forma Information

Pro forma information regarding consolidated income statement information that assumes all of the business acquisitions we have made since January 1, 2014, including the ones listed above, had occurred as of January 1, 2014, is not materially different from the information presented in our accompanying Consolidated Statements of Income.

Asset Purchase

On July 15, 2015, we purchased from Shell US Gas & Power LLC (Shell) its 49% interest in a joint venture, ELC, that was in the pre-construction stage of development for liquefaction facilities at Elba Island, Georgia. The transaction was treated as an asset purchase for the net cash consideration of $185 million. The purchase gives us full ownership and control of ELC. Therefore, we prospectively changed our method of accounting for ELC from the equity method to full consolidation. Shell remains subscribed to 100% of the liquefaction capacity.

Investment Acquisition

On December 10, 2015, we and Brookfield Infrastructure Partners L.P. (Brookfield) acquired from Myria Holdings, Inc. the 53% equity interest in NGPL Holdings LLC not previously owned by us and Brookfield, increasing our ownership to 50% with Brookfield owning the remaining 50%. We paid $136 million for our additional 30% interest in NGPL Holdings LLC. See Note 7 for additional information regarding our equity interests in Kinder Morgan NGPL Holdings LLC.

Investment Divestiture

Effective March 14, 2013, we sold both our one-third ownership interest in the Express pipeline system and our subordinated debenture investment in Express to Spectra Energy Corp. With respect to this sale, during the year ended December 31, 2013, we reported within our accompanying consolidated statement of cash flows $402 million as "Proceeds from sales of assets and investments" and within the accompanying consolidated statement of income a combined $224 million pre-tax gain as "Gain on sale of investments in Express pipeline system" and $84 million of expense within "Income Tax Expense."

Subsequent Event of Terminal Acquisition From and Joint Venture With BP

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $350 million. In conjunction with this transaction, we and BP formed a joint venture, with an equity ownership interest of 75%

and 25%, respectively. We contributed 14 of the acquired terminals to the joint venture, which we will operate, and the remaining terminal is solely owned by us. Of the acquired assets, 10 terminals are included in our Terminals business segment and 5 terminals are included in our Products Pipelines business segment.

4. Impairments and Disposals

We recognized the following non-cash pre-tax impairment charges and losses (gains) on disposals of assets (in millions):

	Year Ended December 31,		
	2015	2014	2013
Natural Gas Pipelines			
Impairment of goodwill	$1,150	$—	$—
Impairments of long-lived assets(a)	79	—	—
Losses (gains) on disposals of long-lived assets	43	5	(28)
Impairment of equity investments(b)	26	—	65
CO_2			
Impairments of long-lived assets(c)	606	243	—
Impairment at equity investee(d)	26	—	—
Terminals			
Impairments of long-lived assets(e)	188	—	—
Losses (gains) on disposals of long-lived assets	3	29	(73)
Impairment of equity investments(e)	4	—	—
Other (gains) losses on disposals of long-lived assets	—	(3)	3
Total losses (gains) on impairments and disposals	$2,125	$274	$(33)

(a) Represents $47 million and $32 million of project write-offs in our non-regulated midstream and regulated natural gas pipelines assets, respectively.
(b) 2015 amount is primarily related to an investment in a gathering and processing asset in Oklahoma and the 2013 amount is related to an investment in our regulated natural gas pipelines.
(c) 2015 amount includes (i) $399 million related to oil and gas properties and (ii) $207 million related to the certain CO_2 source and transportation project write-offs. 2014 amount is primarily related to oil and gas properties.
(d) 2015 amount is a loss on impairment recorded by an investee and included in “Earnings from equity investments” in our accompanying consolidated statement of income.
(e) 2015 amount is primarily related to certain terminals with significant coal operations, including a $175 million impairment ($84 million net after-tax impact to common stockholders) of a terminal facility reflecting the impact of an agreement to adjust certain payment terms under a contract with a coal customer in February 2016.

Impairment of Goodwill

Due to recent events and conditions, interim goodwill impairment testing was performed during December 2015, which resulted in a partial impairment of goodwill in our Natural Gas Pipelines Non-Regulated reporting unit of approximately $1,150 million. See Note 8 for further information.

Impairments of Long-lived Assets

During 2015, the sustained deterioration in the long-term outlook for commodity prices was a triggering event requiring us to perform impairment testing of our assets that are sensitive to such commodity prices. The impairment testing of our long-lived assets was based upon a two-step process as prescribed in the accounting standards.

Step one was performed on each of our oil and gas producing properties and involved a determination as to whether the property's net book value is expected to be recovered from the estimated undiscounted future cash flows for each respective property. To compute estimated future cash flows, we used our independent reserve engineers' estimates of proved reserves, along with our internally developed estimates of probable reserves to develop a long-range plan. Proved reserves are those reserves that our independent reserve engineers have determined are "reasonably certain" to be produced as defined by SEC guidance. Reasonable certainty implies a high degree of confidence, of at least a 90% probability that quantities will equal or exceed the estimate of proved reserves. Probable reserves are those quantities that we have identified in our long range plan that are in excess of our independent reserve engineers' estimates of proved reserves and meet the SEC definition of probable reserves. Probable reserves are defined as reserves that are as "likely as not" to be recoverable with a probability of at least 50% or greater. These estimates of proved and probable reserves are based upon historical performance along with adjustments for expected oil and gas field development. In calculating future cash flows, management utilized estimates of commodity prices based on forward curves. We also included the impact of our existing oil and gas sales contracts to determine the applicable net crude oil and natural gas pricing for each property. Operating expenses were determined based on estimated future fixed and variable field production requirements, and capital expenditures were based on currently authorized projects or economically viable future projects that have been identified for each of our properties. Risk factors were applied to each property's probable reserves based on its operational history or the success of similar properties. Based on the results of the step one test, we determined that certain properties' estimated undiscounted future cash flows were less than their respective carrying values.

For those properties that failed the impairment test's first step, we then made a fair market value assessment using a discounted cash flow analysis as well as an estimate of fair value based upon recent sales prices of comparable properties. Our cash flow analysis was discounted utilizing an estimated weighted average cost of capital of 12%, representing our estimate of the risk-adjusted discount rate that would be used by market participants. We consider the inputs for our impairment calculations to be Level 3 inputs in the fair value hierarchy. Based on these results, we recognized $399 million of impairments on those properties where the carrying value exceeded its estimated fair market value in the period that such a determination was made.

In addition, during 2015 we recorded a $207 million impairment in our CO_2 business segment for certain source and transportation assets. Since we expect CO_2 demand to remain flat for the foreseeable future under the current commodity price environment, we deferred certain source and transportation growth projects beyond our five-year capital expenditures backlog. The extended deferral period necessitated a review of the recoverability of the net book values of these growth projects, resulting in a full impairment of $207 million.

During the year ended December 31, 2015, similar impairment analyses were performed in our other segments resulting in impairments of long-lived assets of $79 million and $188 million, respectively, in our Natural Gas Pipelines and Terminals business segments. These impairments resulted from certain capital projects that were canceled or postponed as well as in our Terminals segment for which certain facilities were impaired as a result of management's re-evaluation of the estimated future cash flows expected to be generated at our coal handling assets.

In the current commodity price environment and to the extent conditions further deteriorate, 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. Because certain of 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. 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 expectations, current and future commodity prices, 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. 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.

5. Income Taxes

The components of "Income from Continuing Operations Before Income Taxes" are as follows (in millions):

Year Ended December 31,

	2015	2014	2013
U.S.	$611	$2,941	$3,107
Foreign	161	150	331
Total Income from Continuing Operations Before Income Taxes	$772	$3,091	$3,438

Components of the income tax provision applicable to continuing operations for federal, foreign and state taxes are as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Current tax expense (benefit)			
Federal	$(125)	$(16)	$57
State	(7)	36	36
Foreign	4	13	9
Total	(128)	33	102
Deferred tax expense (benefit)			
Federal	653	572	612
State	(4)	14	—
Foreign	43	29	28
Total	692	615	640
Total tax provision	$564	$648	$742

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows (in millions, except percentages):

	Year Ended December 31,					
	2015		2014		2013	
Federal income tax	$271	35.0 %	$1,082	35.0 %	$1,203	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	(24)	(3.1)%	—	— %	(21)	(0.6)%
Taxes on foreign earnings	26	3.5 %	40	1.3 %	112	3.3 %
Net effects of consolidating KMP and EPB and other noncontrolling interests	15	2.0 %	(433)	(14.0)%	(488)	(14.2)%
State income tax, net of federal benefit	12	1.5 %	37	1.2 %	45	1.3 %
Dividend received deduction	(51)	(6.6)%	(50)	(1.6)%	(54)	(1.6)%
Adjustments to uncertain tax positions	(14)	(1.9)%	(5)	(0.2)%	(87)	(2.5)%
Valuation allowance on investment in NGPL	—	— %	61	2.0 %	—	— %
Disposition of certain international holdings	—	— %	(112)	(3.6)%	—	— %
Nondeductible goodwill impairment	323	41.7 %	—	— %	—	— %
Other	6	0.8 %	28	0.9 %	32	0.9 %
Total	$564	72.9 %	$648	21.0 %	$742	21.6 %

Deferred tax assets and liabilities result from the following (in millions):

	December 31, 2015	2014
Deferred tax assets		
Employee benefits	$394	$329
Accrued expenses	129	123
Net operating loss, capital loss, tax credit carryforwards	1,344	778
Derivative instruments and interest rate and currency swaps	45	43
Debt fair value adjustment	110	102
Investments	3,607	4,858
Other	3	31
Valuation allowances	(152)	(154)
Total deferred tax assets	5,480	6,110
Deferred tax liabilities		
Property, plant and equipment	143	373
Other	14	30
Total deferred tax liabilities	157	403
Net deferred tax assets	$5,323	$5,707
Current deferred tax asset	$—	$56
Non-current deferred tax assets	5,323	5,651
Net deferred tax assets	$5,323	$5,707

On November 20, 2015, the FASB issued Accounting Standards Update (ASU) 2015-17, “Balance Sheet Classification of Deferred Taxes,” as part of the FASB’s simplification initiative to reduce complexity in accounting standards. The new guidance requires that all deferred tax assets and liabilities for each jurisdiction, along with any valuation allowance, be classified as noncurrent on the balance sheet. The new guidance is effective for public businesses in fiscal years beginning after December 15, 2016. However, as early adoption is permitted as of the beginning of an interim or annual reporting period in which the ASU 2015-17 was issued, we decided to apply the new standard for the December 31, 2015 period. As the guidance allows for prospective application of the new standard, prior period financial statements have not been retrospectively adjusted.

Deferred Tax Assets and Valuation Allowances: The step-up in tax basis from the Merger Transactions in November 2014 resulted in a deferred tax asset related to our investments (primarily in KMP) of $3.6 billion and $4.9 billion at December 31, 2015 and 2014, respectively. As book earnings from our investment in KMP are projected to exceed taxable income (primarily as a result of the partnership’s tax depreciation in excess of book depreciation), the deferred tax asset related to our investment in KMP is expected to be fully realized.

We recorded a full valuation allowance of $61 million against the deferred tax asset at December 31, 2014 related to our investment in NGPL as we concluded it was no longer realizable.

We have deferred tax assets of $1,005 million related to net operating loss carryovers, $339 million related to alternative minimum and foreign tax credits, and $91 million of valuation allowances related to deferred tax assets at December 31, 2015. As of December 31, 2014, we had deferred tax assets of $466 million related to net operating loss carryovers, $312 million related to alternative minimum and foreign tax credits, and valuation allowances related to deferred tax assets of $93 million. We expect to generate taxable income beginning in 2019 and utilize all federal net operating loss carryforwards and alternative minimum tax carryforwards by the end of 2023.

Expiration Periods for Deferred Tax Assets: As of December 31, 2015, we have U.S. federal net operating loss carryforwards of $2.4 billion, which will expire from 2018 - 2035; state losses of $3.1 billion which will expire from 2015 - 2035; and foreign losses of $154 million, of which approximately $115 million carries over indefinitely and $39 million expires from 2028 - 2035. We also have $312 million of federal alternative minimum tax credits which do not expire; and approximately $26 million of foreign tax credits, the majority of which will expire from 2016 - 2025. Use of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal

Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations.

Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

A reconciliation of our gross unrecognized tax benefit excluding interest and penalties is as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Balance at beginning of period	$189	$209	$269
Uncertain tax positions of EP	—	—	4
Subtotal	189	209	273
Additions based on current year tax positions	4	12	11
Additions based on prior year tax positions	—	—	26
Reductions based on prior year tax positions	(6)	(3)	—
Reductions based on settlements with taxing authority	(25)	(24)	(86)
Reductions due to lapse in statute of limitations	(14)	(5)	(15)
Balance at end of period	$148	$189	$209

We recognize interest and/or penalties related to income tax matters in income tax expense. As of December 31, 2015, 2014, and 2013, we had $24 million, $28 million and $29 million, respectively, of accrued interest and $2 million, $2 million and $2 million, respectively, in accrued penalties. All of the $148 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $5 million during the next year to approximately $143 million.

We are subject to taxation, and have tax years open to examination for the periods 2011-2014 in the U.S., 2002-2014 in various states and 2007-2014 in various foreign jurisdictions.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2015 and 2014, our property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2015	2014
Pipelines (Natural gas, liquids, crude oil and CO_2)	$19,855	$18,119
Equipment (Natural gas, liquids, crude oil, CO_2, and terminals)	22,979	21,233
Other(a)	4,719	4,484
Accumulated depreciation, depletion and amortization	(10,851)	(8,369)
	36,702	35,467
Land and land rights-of-way	1,450	1,324
Construction work in process	2,395	1,773
Property, plant and equipment, net	$40,547	$38,564

(a) Includes buildings, computer and communication equipment, vessels, linefill and other.

As of December 31, 2015 and 2014, property, plant and equipment included $16,089 million and $15,026 million, respectively, of assets which were regulated by either the FERC or the NEB. Depreciation, depletion, and amortization expense charged against property, plant and equipment was $2,059 million, $1,862 million, and $1,663 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Asset Retirement Obligations

As of December 31, 2015 and 2014, we recognized asset retirement obligations in the aggregate amount of $215 million and $192 million, respectively, of which $9 million and $7 million, respectively, were classified as current. The majority of our asset retirement obligations are associated with our CO2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors.

7. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. As of December 31, 2015 and 2014, our investments consisted of the following (in millions):

	December 31,	
	2015	2014
Citrus Corporation	$1,719	$1,805
Ruby Pipeline Holding Company, L.L.C.	1,093	1,123
MEP	713	748
Gulf LNG Holdings Group, LLC	516	547
EagleHawk	348	337
Plantation Pipe Line Company	327	303
Watco Companies, LLC	201	103
Red Cedar Gathering Company	185	184
Double Eagle Pipeline LLC	158	150
Kinder Morgan NGPL Holdings LLC	153	—
Parkway Pipeline LLC	131	144
FEP	116	130
Fort Union Gas Gathering L.L.C.	50	70
Sierrita Gas Pipeline LLC	60	63
Cortez Pipeline Company	—	17
All others	262	304
Total equity investments	6,032	6,028
Bond investments	8	8
Total investments	$6,040	$6,036

As shown in the table above, our significant equity investments, as of December 31, 2015 consisted of the following:

- Citrus Corporation—We own a 50% interest in Citrus Corporation, the sole owner of Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,300-mile natural gas pipeline. Energy Transfer Partners L.P. operates and owns the remaining 50% interest;
- Ruby Pipeline Holding Company, L.L.C.—We operate and own a 50% interest in Ruby Pipeline Holding Company, L.L.C., the sole owner of Ruby Pipeline natural gas transmission system. The remaining 50% interest is owned by a subsidiary of Veresen Inc. as convertible preferred interests;
- MEP—We operate and own a 50% interest in MEP, the sole owner of the Midcontinent Express natural gas pipeline system. The remaining 50% ownership interest is owned by subsidiaries of Energy Transfer Partners L.P.;
- Gulf LNG Holdings Group, LLC—We operate and own a 50% interest in Gulf LNG Holdings Group, LLC, the owner of a LNG receiving, storage and regasification terminal near Pascagoula, Mississippi, as well as pipeline facilities to deliver vaporized natural gas into third party pipelines for delivery into various markets around the country. The remaining 50% ownership interests are wholly and partially owned by subsidiaries of GE Financial Services and The

Blackstone Group L.P.;

- BHP Billiton Petroleum (Eagle Ford) LLC, f/k/a EagleHawk and referred to in this report as EagleHawk—We own a 25% interest in EagleHawk, the sole owner of natural gas and condensate gathering systems serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton Petroleum operates EagleHawk and owns the remaining 75% ownership interest;
- Plantation—We operate and own a 51.17% interest in Plantation, the sole owner of the Plantation refined petroleum products pipeline system. A subsidiary of Exxon Mobil Corporation owns the remaining interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered substantive participating rights; therefore, we do not control Plantation, and account for the investment under the equity method;
- Watco Companies, LLC—We hold a preferred equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. We own 100,000 Class A and 50,000 Class B preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash and stock distributions from the preferred shares at a rate of 3.25% and 3.00% per quarter, respectively, and participate partially in additional profit distributions at a rate equal to 0.5%. The Class A preferred shares have no conversion features and neither class holds any voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. In addition to the senior interests, we also hold approximately 26,000 common equity units, which represents a 7.2% ownership that is accounted for under the equity method of accounting;
- Red Cedar Gathering Company—We own a 49% interest in Red Cedar Gathering Company, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The Southern Ute Indian Tribe owns the remaining 51% interest;
- Double Eagle Pipeline LLC - We own a 50% equity interest in Double Eagle Pipeline LLC. The remaining 50% interest is owned by Magellan Midstream Partners;
- Kinder Morgan NGPL Holdings LLC— We operate and own a 50% interest in NGPL Holdings LLC, the indirect owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system. Effective December 10, 2015 we and Brookfield acquired from Myria Holdings, Inc. the 53% equity interest in NGPL Holdings LLC not previously owned by us and Brookfield, increasing our ownership to 50% with Brookfield owning the remaining 50%. We paid $136 million for our additional 30% interest in NGPL Holdings LLC and during December 2015 we made an additional contribution of $17 million.
- Parkway Pipeline LLC —We operate and own a 50% interest in Parkway Pipeline LLC, the sole owner of the Parkway Pipeline refined petroleum products pipeline system. Valero Energy Corp. owns the remaining 50% interest;
- FEP —We own a 50% interest in FEP, the sole owner of the Fayetteville Express natural gas pipeline system. Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of FEP;
- Fort Union Gas Gathering LLC—We own a 37.04% equity interest in the Fort Union Gas Gathering LLC. Crestone Powder River LLC, a subsidiary of ONEOK Partners L.P., owns 37.04%; Powder River Midstream, LLC owns 11.11%; and Western Gas Wyoming, LLC owns the remaining 14.81%. Western Gas Resources, Inc. serves as operator of Fort Union Gas Gathering LLC;
- Sierrita Gas Pipeline LLC — We operate and own a 35% equity interest in the Sierrita Gas Pipeline LLC. MGI Enterprises U.S. LLC, a subsidiary of PEMEX, owns 35%; and MIT Pipeline Investment Americas, Inc., a subsidiary of Mitsui & Co., Ltd, owns 30%; and
- Cortez Pipeline Company—We operate and own a 50% interest in the Cortez Pipeline Company, the sole owner of the Cortez carbon dioxide pipeline system. A subsidiary of Exxon Mobil Corporation owns a 37% interest and Cortez Vickers Pipeline Company owns the remaining 13% interest.

Our earnings (losses) from equity investments were as follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Citrus Corporation	$96	$97	$84
FEP	55	55	55
Gulf LNG Holdings Group, LLC	49	48	47
MEP	45	45	40
Red Cedar Gathering Company	26	33	31
EagleHawk	24	(7)	9
Plantation Pipe Line Company	29	29	35
Ruby Pipeline Holding Company, L.L.C.	18	15	(6)
Watco Companies, LLC	16	13	13
Sierrita Gas Pipeline LLC	9	3	—
Parkway Pipeline LLC	5	8	1
Double Eagle Pipeline LLC(a)	3	(1)	1
Cortez Pipeline Company(b)	(3)	25	24
Fort Union Gas Gathering L.L.C.(a)(c)	(4)	16	11
NGPL Holdco LLC(d)	—	—	(66)
All others	16	27	48
Total	$384	$406	$327
Amortization of excess costs	$(51)	$(45)	$(39)

(a) 2013 amounts are for the period from May 1, 2013 through December 31, 2013.
(b) 2015 amount includes $26 million representing our share of a non-cash impairment charge (pre-tax) recorded by Cortez Pipeline Company.
(c) 2015 amount includes a non-cash impairment charge of $20 million (pre-tax) related to our investment.
(d) 2013 amount includes non-cash impairment charges of $65 million (pre-tax) related to our investment.

Summarized combined financial information for our significant equity investments (listed or described above) is reported below (in millions; amounts represent 100% of investee financial information):

	Year Ended December 31,		
Income Statement	2015	2014	2013
Revenues	$3,857	$3,829	$3,615
Costs and expenses	3,408	3,063	2,803
Net income (loss)	$449	$766	$812

	December 31,	
Balance Sheet	2015	2014
Current assets	$811	$943
Non-current assets	19,745	20,630
Current liabilities	1,009	1,643
Non-current liabilities	11,227	10,841
Partners'/owners' equity	8,320	9,089

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2015 and 2014 are summarized by reporting unit as follows (in millions):

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO2	Products Pipelines	Products Pipelines Terminals	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$17,527	$ 5,637	$1,528	$1,908	$221	$1,486	$610	$28,917
Accumulated impairment losses	(1,643)	(447)	—	(1,197)	(70)	(679)	(377)	(4,413)
December 31, 2013	15,884	5,190	1,528	711	151	807	233	24,504
Acquisitions(a)	—	82	—	—	—	89	—	171
Currency translation	—	—	—	—	—	—	(19)	(19)
Divestiture	—	—	—	—	—	(2)	—	(2)
December 31, 2014	15,884	5,272	1,528	711	151	894	214	24,654
Acquisitions(b)	—	93	—	217	—	11	—	321
Currency translation	—	—	—	—	—	—	(35)	(35)
Impairment	—	(1,150)	—	—	—	—	—	(1,150)
December 31, 2015	$15,884	$ 4,215	$1,528	$928	$151	$905	$179	$23,790

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(a) 2014 includes $82 million related to the May 2013 Copano acquisition in Natural Gas Pipelines Non-Regulated and $89 million related to Terminals' acquisitions of APT tankers in January 2014 and Crowley tankers in November 2014, as discussed in Note 3.

(b) 2015 includes $93 million and $217 million, respectively, related to the February 2015 acquisition of Hiland by Natural Gas Pipelines Non-Regulated and Products Pipelines, and $7 million related to the February 2015 acquisition of Vopak terminal assets by Terminals, all of which are discussed in Note 3.

Refer to Note 2 "Summary of Significant Accounting Policies—Goodwill" for a description of our accounting for goodwill and Note 4 for further discussion regarding impairments.

We determined the fair value of each reporting unit as of May 31, 2015, based primarily on a market approach utilizing a median dividend/distribution yield of comparable companies. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price estimated to be received in a sale of the reporting unit in an orderly transaction between market participants at the measurement date. The results of our annual test during the second quarter indicated fair value in excess of carrying value for each of our reporting units. We noted no significant events or conditions during the third quarter of 2015 that would have affected the conclusions from our annual assessment in the prior quarter.

During the month of December 2015, consistent with decreases in certain market indices which track the market sectors in which we operate, the Company's market capitalization decreased by approximately 36% after experiencing declines earlier in the quarter. During the fourth quarter 2015, many energy companies also indicated their dividends/distributions may be impacted by the ongoing effect of commodity prices on market conditions in the energy sector. As discussed above, our step 1 test performed as of May 31, 2015, used market valuations primarily based on dividend/distribution yields. This indicated that our prior step 1 valuations required re-evaluation. Based on these indicators and related factors, we conducted an interim test of the recoverability of goodwill as of December 31, 2015.

Our step 1 test as of December 31, 2015, utilized both a market approach and income approach to estimate the fair values of our reporting units. The market approach was based on enterprise value (EV) to estimated EBITDA multiples. We believe these multiples appropriately reflect fair value for purposes of our step 1 goodwill impairment test because EV/EBITDA is not dependent on dividend/distribution policy, capital structure or tax profile. For our Natural Gas Pipelines Regulated and Non-Regulated and our CO_2 reporting units, we also conducted a discounted cash flow analysis (income approach) to evaluate the fair value of these reporting units to provide additional indication of fair value based on the present value of cash flows these reporting units are expected to generate in the future. We weighted the market and income approaches for these reporting units to arrive at an estimated fair value of these respective reporting units giving more weighting on the income approach and less on the market approach as we believed the values indicated using the income approach are more representative of the value that could be received from a market participant. With the exception of our Natural Gas Pipelines Non-Regulated reporting unit, each of our reporting units indicated a fair value in excess of their respective carrying values. The amount of excess fair value over the carrying value ranged from approximately 3% for our Natural Gas Pipelines Regulated reporting unit to 104% for our Products Pipelines Terminals. If the fair value of the Natural Gas Pipelines Regulated reporting unit decreased by approximately 3%, it could indicate a possible failure of the step 1 test. The primary assumptions in our step 1 market approach test include the following:

- We selected a peer group of midstream companies with large market capitalizations with comparable operations, economic characteristics, and assets which generally include significant holdings of interstate transmission pipelines, midstream gathering and processing systems, and/or terminal operations. We use this peer group for all of our reporting units with the exception of our CO_2 reporting unit. We estimated the median enterprise value to EBITDA multiple to be approximately 12.7x, without consideration of any control premium.
- For our CO_2 reporting unit, we utilized a group of large independent oil and gas exploration and production companies which generally have operations similar to ours and include assets in the Permian basin where we operate and may have enhanced oil recovery operations similar to ours. We estimated the median enterprise value to EBITDA multiple for this peer group to be approximately 7.9x, without consideration of any control premium.
- In calculating the market multiples, we used estimates of enterprise value as of December 31, 2015, and consensus estimates of the 2015 EBITDA for each company in the peer group obtained from a third party provider of financial data. Estimates of enterprise value were calculated based on market capitalization plus net debt utilizing the most recent data available as of December 31, 2015. EV/EBITDA multiples are sensitive to changes in the components that comprise the ratio, including EBITDA, market capitalizations, and debt of the peer group companies.
- We assessed the reasonableness of the control premium implied by the above market valuations as the market multiples include equity values on a non-controlling basis. As such, we considered the implied control premium as part of our reconciliation of our total reporting unit estimated fair value to our market capitalization which indicated an implied control premium of 34%, which we considered to be reasonable.

For our CO_2 reporting unit, the above market approach indicated a fair value of approximately 7.9x EBITDA. Management concluded because of current commodity price conditions, the fair value based on the market approach should be given partial weighting with a discounted cash flow analysis. The discounted cash flow analysis indicated a fair value of approximately 4.1x EBITDA. Based on a weighting of the market and income approaches, we determined a fair value of the CO_2 reporting unit of approximately 5.1x EBITDA. If the fair value of the CO_2 reporting unit decreased by approximately 12%, this could indicate a possible impairment of goodwill requiring a step 2 analysis.

Applying the market approach to our Natural Gas Pipeline Non-Regulated reporting unit indicated an 18% deficit of fair value as compared to carrying value. We also applied an income approach to this reporting unit, which indicated a deficit of fair value of approximately 4% as compared to the carrying value. The results of our step 1 test of our Natural Gas Pipelines Non-Regulated reporting unit indicated that our carrying value exceeded the fair value thereby requiring us to perform a step 2 evaluation. The primary assumptions in our step 1 income approach for this reporting unit include the following:

- Based on the weighted-average cost of capital of the peer group, we determined the appropriate rate at which to discount the cash flows is 8%. Each 100 basis points change in the discount rate changes the estimated fair value by approximately 5%.
- We used a five-year forward commodity price curve which assumed $38 crude and $2.50 natural gas in 2016 gradually increasing over the following five years to $65 and $3.50, respectively, and then remaining flat. Management developed this price curve based on the year-end NYMEX price curve and a third party median consensus five year forward price curve.
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- We estimated cash flows based on 6 years of projections and applied exit multiples, ranging from 10x to 15x based on management's expectations of those that would be applied by a market participant and market transactions for comparable assets, to year 6 cash flows. These cash flows have various assumptions on volumes and prices based on management's expectations for each underlying component asset within the reporting unit.
- We estimated ethane fractionation spreads based on the relationship between ethane and natural gas prices. Our estimates assumed $(0.01) for 2016-2017, increasing to $0.15 in 2018 through 2021 based on a trailing five-year average spreads as management expects demand to increase commensurate with expected petrochemical capacity and export facilities coming online around that time.
- Consistent with how we evaluate potential acquisitions and we believe a market participant would do, we assumed a certain amount of capital expenditure, including for projects that are already in progress, and consistent with historical levels as adjusted for commodity prices assumptions and customer activity. We assumed an approximate 12% return on this invested capital beginning in the years the assets are expected to be placed in service.

After considering the market and income approaches, we determined the $19.0 billion carrying value of this reporting unit exceeded the estimated fair value of $17.2 billion, and therefore conducted a step 2 analysis. The fair value was estimated based on a weighting of the market and income approaches for this reporting unit. This implies an EBITDA valuation of approximately 14.0x. Management believes this is a reasonable estimate of fair value based on comparable sales transactions and the fact that it implies a reasonable control premium at the reporting unit level.

Below is a hypothetical allocation of the fair value to the assets and liabilities of this reporting unit, including goodwill. The amount of implied goodwill is then compared to the carrying value of goodwill to determine the amount of impairment (in millions).

Allocation of Fair Value:		
Working capital, net	$232	
Property, plant and equipment	9,627	
Other intangible assets	3,121	
Other liabilities, net	(7	)
Goodwill	4,215	
Estimated Reporting Unit Fair Value	$17,188	
Prior carrying amount of goodwill	$5,365	
Goodwill impairment	$1,150	

The key assumptions used in determining the fair value of the assets and liabilities of the reporting unit are as follows:

- Working capital and other liabilities were assumed to have fair values that approximate carrying value as these generally relate to monetary assets and liabilities that settle in the short-term, derivative positions that are recorded at fair value, and inventory which has been subjected to lower of cost or market adjustments in a declining commodity price environment.
- With respect to property, plant and equipment, and other intangibles, the company based its determination of fair values on previously completed fair value studies conducted for these assets as updated for developments subsequent to the date of the initial studies.
- The fair value allocation assumed the reporting unit would be sold in a taxable transaction.

The result of our step 2 analysis was a partial impairment of goodwill in our Natural Gas Pipelines Non-Regulated reporting unit of approximately $1,150 million. The above fair value estimates are based on Level 3 Inputs of the fair value hierarchy.

The sustained decrease and the long-term outlook in commodity prices have adversely impacted our customers and their future capital and operating plans. A continued or 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. A significant change to any one or combination of these factors would result in a change to the reporting unit fair values discussed above which could lead to further impairment charges. This would negatively impact our estimates of the fair values of our reporting units and could cause impairments of long-lived assets, equity method investments, and/or goodwill. Such non-cash impairments from one or both, or any, of these reportable units could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value exceeds fair value.

9. 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. In 2015, we adopted Accounting Standards Updates (ASU)

2015-03, “Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs” and ASU 2015-15, “Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements—Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update).” These ASUs are designed to simplify presentation of debt issuance costs. The standards require that debt issuance costs related to a recognized debt liability, except for line-of-credit debt issuance costs, be presented in the balance sheet as an offset to the carrying amount of that debt liability, consistent with debt discounts. The application of this new accounting guidance resulted in the reclassification of $149 million of debt issuance costs from “Deferred charges and other assets” to “Debt fair value adjustments” in our accompanying consolidated balance sheet as of December 31, 2014.

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 and premiums (in millions):

	December 31,	
	2015	2014
KMI		
Senior notes 1.50% through 8.25%, due 2015 through 2098(a)(b)(c)	$13,346	$11,438
Credit facility due November 26, 2019(d)(e)	—	850
Commercial paper borrowings(d)(e)	—	386
KMP		
Senior notes, 2.65% through 9.00%, due 2015 through 2044(b)(f)	19,985	20,660
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(b)(h)	1,790	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032(b)	1,115	1,115
Copano senior notes, 7.125%, due April 1, 2021(b)	332	332
CIG senior notes, 5.95% through 6.85%, due 2015 through 2037(b)	100	475
SNG notes, 4.40% through 8.00%, due 2017 through 2032(b)(g)	1,211	1,211
Other Subsidiary Borrowings (as obligor)		
Kinder Morgan Finance Company, LLC, senior notes, 5.70% through 6.40%, due 2016 through 2036(b)(h)	1,636	1,636
Hiland Partners Holdings LLC, senior notes, 5.50% and 7.25%, due 2020 and 2022(b)(i)	974	—
EPC Building, LLC, promissory note, 3.967%, due 2015 through 2035	443	453
Preferred securities, 4.75%, due March 31, 2028(j)	221	280
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock(k)	100	100
Other miscellaneous debt(l)	300	303
Total debt – KMI and Subsidiaries	41,553	41,029
Less: Current portion of debt(m)	821	2,717
Total long-term debt – KMI and Subsidiaries(n)	$40,732	$38,312

(a) December 31, 2015 amount includes senior notes that are denominated in Euros and have been converted and are reported at the December 31, 2015 exchange rate of 1.0862 U.S. dollars per Euro. From the issuance date of these senior notes in March 2015 through December 31, 2015, our debt increased by less than $1 million as a result of the change in the exchange rate of U.S dollars per Euro. We entered into cross-currency swap agreements associated with these senior notes (see Note 14 “Risk Management—Foreign Currency Risk Management”).

(b) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium and are subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(c) Includes $6.0 billion of senior notes issued on November 26, 2014 as a result of the Merger Transactions (see “—Long-term Debt Issuances and Repayments” below).

(d) As of December 31, 2014, the weighted average interest rate on our credit facility borrowings, including commercial paper borrowings, was 1.54%.

(e) On November 26, 2014, we entered into a $4 billion replacement credit facility and a commercial paper program of up to $4 billion of unsecured notes (see “—Credit Facilities and Restrictive Covenants” below).

(f) On January 1, 2015, EPB and EPPOC merged with and into KMP. On that date, KMP succeeded EPPOC as the issuer of approximately $2.9 billion of EPPOC’s senior notes, which were guaranteed by EPB, and EPB and EPPOC ceased to be obligors for those senior notes.

(g) Southern Natural Issuing Corporation is a wholly owned finance subsidiary of SNG and is the co-issuer of certain of SNG's outstanding debt securities.

(h) In January and February 2016, we refinanced $850 million of maturing Kinder Morgan Finance Company LLC senior notes and $150 million of maturing TGP senior notes using proceeds from a new three-year term loan facility (see "— Subsequent Event—Debt Issuances and Repayments" below).

(i) Represents the remaining principal amount outstanding of senior notes assumed in the Hiland acquisition.

(j) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2015, had 4.4 million of 4.75% trust convertible preferred securities outstanding (referred to as the Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; (ii) $25.18 in cash without interest; and (iii) 1.100 warrants to purchase a share of our Class P common stock. We have the right to redeem these Trust I Preferred Securities at any time. Because of the substantive conversion rights of the securities into the mixed consideration, we bifurcated the fair value of the Trust I

Preferred Securities into debt and equity components and as of December 31, 2015, the outstanding balance of $221 million (of which $111 million is classified as current) was bifurcated between debt ($197 million) and equity ($24 million). During the years ended December 31, 2015 and 2014, 1,176,015 and 3,923 Trust I Preferred Securities had been converted into (i) 846,369 and 2,820 shares of our Class P common stock; (ii) approximately $30 million and $99,000 in cash; and (iii) 1,293,615 and 4,315 in warrants, respectively.

(k) As of December 31, 2015 and 2014, KMGP had outstanding 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Since August 18, 2012, dividends on the preferred stock accumulate at a floating rate of the 3-month LIBOR plus 3.8975% and are payable quarterly in arrears, when and if declared by KMGP's board of directors, on February 18, May 18, August 18 and November 18 of each year, beginning November 18, 2012. The preferred stock has approval rights over a commencement of or filing of voluntary bankruptcy by KMP or its SFPP or Calnev subsidiaries.

(l) In conjunction with the construction of the Totem Gas Storage facility (Totem) and the High Plains pipeline (High Plains), CIG's joint venture partner in WYCO funded 50% of the construction costs. Upon project completion, the advances were converted into a financing obligation to WYCO. As of December 31, 2015, the principal amounts of the Totem and High Plains financing obligations were $72 million and $96 million, respectively, which will be paid in monthly installments through 2039 based on the initial lease term. The interest rate on these obligations is 15.5%, payable on a monthly basis.

(m) Amounts include outstanding credit facility and commercial paper borrowings and other debt maturing within 12 months. See "—Maturities of Debt" below.

(n) Excludes our "Debt fair value adjustments" which, as of December 31, 2015 and December 31, 2014, increased our combined debt balances by $1,674 million and $1,785 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs (resulting from the implementation of ASU No. 2015-03 and 2015-15) 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. For further information about our debt fair value adjustments, see Note 15 "Fair Value—Debt Fair Value Adjustments."

We and substantially all of our 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 19.

Credit Facilities and Restrictive Covenants

On September 19, 2014, we entered into a new five-year $4.0 billion revolving credit agreement with a syndicate of lenders, which can be increased to $5.0 billion if certain conditions are met (see "—Subsequent Event—Credit Facility Capacity" following). The new revolving credit agreement was effective upon the closing of the Merger Transactions on November 26, 2014 and replaced the prior KMI credit agreement, the KMP credit agreement and the EPB credit agreement. On November 26, 2014, we entered into a $4.0 billion commercial paper program through the private placement of short-term notes. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par. 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.

Our credit facility borrowings bear interest at either (i) LIBOR plus an applicable margin ranging from 1.125% to 2.000% per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; and (3) LIBOR Rate for a one month eurodollar loan, plus 1%, plus, in each case, an applicable margin ranging from 0.125% to 1.00% per annum based on our credit rating. As of December 31, 2015, we were in compliance with all required financial covenants.

Our credit facility included the following restrictive covenants as of December 31, 2015:

- total debt divided by earnings before interest, income taxes, depreciation and amortization may not exceed:
- 6.50: 1.00, for the period ended on or prior to December 31, 2017; or
- 6.25: 1.00, for the period ended after December 31, 2017 and on or prior to December 31, 2018; or
- 6.00: 1.00, for the period ended after December 31, 2018;
- certain limitations on indebtedness, including payments and amendments;
- certain limitations on entering into mergers, consolidations, sales of assets and investments;
- limitations on granting liens; and
- prohibitions on making any dividend to shareholders if an event of default exists or would exist upon making such dividend.

As of December 31, 2015, we had no borrowings outstanding under our five-year $4.0 billion revolving credit facility, no borrowings outstanding under our $4.0 billion commercial paper program and $115 million in letters of credit. Our availability under this facility as of December 31, 2015 was $3,885 million.

On February 13, 2015, in connection with the Hiland acquisition, we entered into and made borrowings of $1,641 million under a new six-month bridge credit facility with UBS AG, Stamford Branch. Interest under this bridge credit facility was charged at the same rate as our $4.0 billion revolving credit facility. Prior to March 31, 2015, we repaid outstanding borrowings and the facility was terminated on April 6, 2015.

Subsequent Event—Credit Facility Capacity

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 terms of the revolving credit agreement remain the same.

Hiland Debt Acquired
As of the February 13, 2015 Hiland acquisition date, we assumed (i) $975 million in principal amount of senior notes (which were valued at $1,043 million as of the acquisition date) and (ii) $368 million of other borrowings that were immediately repaid after closing, primarily consisting of borrowings outstanding under a revolving credit facility. The senior notes are subject to our cross guarantee agreement discussed in Note 19.

Long-term Debt Issuances and Repayments
Apart from the assumption of the Hiland debt discussed above, following are significant long-term debt issuances and repayments made during 2015 and 2014:

	2015	2014
Issuances	$800 million 5.05% notes due 2046	$650 million senior term loan facility due 2017
	$815 million 1.50% notes due 2022(a)	$500 million 2.00% notes due 2017(b)
	$543 million 2.25% notes due 2027(a)	$1,500 million 3.05% notes due 2019(b)
		$1,500 million 4.30% notes due 2025(b)
		$750 million 5.30% notes due 2034(b)
		$1,750 million 5.55% notes due 2045(b)
		$750 million 3.50% notes due 2021
		$750 million 5.50% notes due 2044
		$650 million 4.25% notes due 2024
		$550 million 5.40% notes due 2044
		$600 million 4.30% notes due 2024
Repayments	$300 million 5.625% notes due 2015	$500 million 5.125% notes due 2014
	$250 million 5.15% notes due 2015	$1,528 million senior term loan facility due 2015
	$340 million 6.80% notes due 2015	$650 million senior term loan facility due 2017(b)
	$375 million 4.10% notes due 2015	$207 million 6.875% notes due 2014

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(a) Senior notes are denominated in Euros and are presented above in U.S. dollars at the exchange rate on the issuance date of 1.0860 U.S. dollars per Euro. We entered into cross-currency swap agreements associated with these senior notes (see Note 14—"Risk Management—Foreign Currency Risk Management").
(b) Debt issued or repaid associated with the Merger Transactions.

Subsequent Event—Debt Issuances and Repayments

In January 2016, we entered into a $1.0 billion three-year unsecured term loan facility due in 2019 at 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 at December 31, 2015.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2015, are summarized as follows (in millions):

Year	Total
2016(a)	$821
2017	3,060
2018	2,329
2019(a)	3,819
2020	2,953
Thereafter	28,571
Total	$41,553

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(a) 2016 amount primarily includes $667 million of current maturities on senior notes and $111 million associated with our Trust I Preferred Securities that are classified as current obligations because these securities have rights to convert into consideration consistent with the EP merger, and excludes $1,000 million of current maturities on long-term debt that were refinanced with proceeds from the issuance of a January 2016 three-year term loan which is reflected in 2019.

Debt Fair Value Adjustments

The carrying value adjustment to debt securities whose fair value is being hedged is included within "Debt fair value adjustments" on our accompanying consolidated balance sheets. "Debt fair value adjustments" also include unamortized debt discount/premiums, purchase accounting debt fair value adjustments, unamortized portion of proceeds received from the early termination of interest rate swap agreements, and debt issuance costs. As of December 31, 2015, the weighted-average amortization period of the unamortized premium from the termination of the interest rate swaps was approximately 16 years. The following table summarizes the "Debt fair value adjustments" included on our accompanying consolidated balance sheets (in millions):

	December 31,	
Debt Fair Value Adjustments	2015	2014
Purchase accounting debt fair value adjustments	$1,135	$1,221
Carrying value adjustment to hedged debt	380	347
Unamortized portion of proceeds received from the early termination of interest rate swap agreements	397	454
Unamortized debt discount/premiums	(86)	(88)
Unamortized debt issuance costs	(152)	(149)
Total debt fair value adjustments	$1,674	$1,785

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 4.92% during 2015 and 5.02% during 2014. Information on our interest rate swaps is contained in Note 14. For information about our contingent debt agreements, see Note 13 "Commitments and Contingent Liabilities—Contingent Debt").

10. Share-based Compensation and Employee Benefits

Share-based Compensation

Class P Shares

Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors

We have a Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive shares of Class P common stock. Each election will be generally at or around the first board meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2015, 2014 and 2013, we made restricted Class P common stock grants to our non-employee directors of 9,580, 6,210 and 5,710, respectively. These grants were valued at time of issuance at $401,000, $220,000 and $210,000, respectively. All of the restricted stock awards made to non-employee directors vest during a six-month period.

Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan

The Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan is an equity awards plan available to eligible employees. The following table sets forth a summary of activity and related balances of our restricted stock awards excluding that issued to non-employee directors (in millions, except share amounts):

	Year Ended December 31, 2015		Year Ended December 31, 2014		Year Ended December 31, 2013	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	7,373,294	$277	6,382,885	$239	2,154,022	$69
Granted	1,488,467	57	1,694,668	61	4,563,495	181
Vested	(817,797)	(29)	(460,032)	(14)	(83,444)	(3)
Forfeited	(398,859)	(15)	(244,227)	(9)	(251,188)	(8)
Outstanding at end of period	7,645,105	$290	7,373,294	$277	6,382,885	$239
Intrinsic value of restricted stock awards vested during the period		$31		$17		$3

Restricted stock awards made to employees have vesting periods ranging from 1 year with variable vesting dates to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares
2016	1,096,290
2017	1,563,549
2018	2,443,888
2019	1,688,831
2020	585,574
Thereafter	266,973
Total Outstanding	7,645,105

The related expense less estimated forfeitures is generally recognized ratably over the vesting period of the restricted stock awards. Upon vesting, the grants will be paid in our Class P common shares.

During 2015, 2014 and 2013, we recorded $67 million, $57 million and $35 million, respectively, in expense related to restricted stock awards. At December 31, 2015 and 2014, unrecognized restricted stock awards compensation expense, less estimated forfeitures, was approximately $154 million and $170 million, respectively.

Pension and Other Postretirement Benefit Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain plan participants' contributions and Company contributions are based on collective bargaining agreements. The total expense for our savings plan was approximately $46 million, $42 million, and $40 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Pension Plans

Our pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. A participant in the cash balance plan accrues benefits through contribution credits based on a combination of age and years of service times eligible compensation. Interest is also credited to the participant's plan account. A participant becomes fully vested in the plan after three years, and may take a lump sum distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees continue to accrue benefits through career pay or final pay formulas.

Other Postretirement Benefit Plans

We and certain of our U.S. subsidiaries provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees and certain grandfathered employees and their dependents, and limited postretirement life insurance benefits for retired employees. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and we reserve the right to change these benefits. Effective January 1, 2014, the plan was amended to provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange.

Additionally, our subsidiary SFPP has incurred certain liabilities for postretirement benefits to certain current and former employees, their covered dependents, and their beneficiaries. However, the net periodic benefit costs, contributions and liability amounts associated with the SFPP postretirement benefit plan are not material to our consolidated income statements or balance sheets.

Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2015 and 2014 (in millions):

	Pension Benefits		OPEB	
	2015	2014	2015	2014
Change in benefit obligation:				
Benefit obligation at beginning of period	$2,804	$2,563	$624	$631
Service cost	33	21	—	—
Interest cost	99	112	21	25
Actuarial (gain) loss	(109)	294	(101)	15
Benefits paid	(173)	(186)	(39)	(52)
Participant contributions	—	—	2	3
Medicare Part D subsidy receipts	—	—	2	2
Benefit obligation at end of period	2,654	2,804	509	624
Change in plan assets:				
Fair value of plan assets at beginning of period	2,377	2,333	389	380
Actual (loss) return on plan assets	(204)	180	(45)	32
Employer contributions	50	50	16	25
Participant contributions	—	—	2	3
Medicare Part D subsidy receipts	—	—	2	1
Benefits paid	(173)	(186)	(39)	(52)
Fair value of plan assets at end of period	2,050	2,377	325	389
Funded status - net liability at December 31,	$(604)	$(427)	$(184)	$(235)

Components of Funded Status. The following table details the amounts recognized in our balance sheet at December 31, 2015 and 2014 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2015	2014	2015	2014
Non-current benefit asset	$—	$—	$139	$173
Current benefit liability	—	—	(16)	(22)
Non-current benefit liability	(604)	(427)	(307)	(386)
Funded status - net liability at December 31,	$(604)	$(427)	$(184)	$(235)

Components of Accumulated Other Comprehensive (Loss) Income. The following table details the amounts of pre-tax accumulated other comprehensive (loss) income at December 31, 2015 and 2014 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets, including the portion attributable to our noncontrolling interests, (in millions):

	Pension Benefits		OPEB	
	2015	2014	2015	2014
Unrecognized net actuarial (loss) gain	$(558)	$(296)	$23	$(27)
Unrecognized prior service (cost) credit	(4)	(4)	19	20
Accumulated other comprehensive (loss) income	$(562)	$(300)	$42	$(7)

We anticipate that approximately $28 million of pre-tax accumulated other comprehensive loss will be recognized as part of our net periodic benefit cost in 2016, including approximately $29 million of unrecognized net actuarial loss and approximately $1 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was $2,615 million and $2,719 million at December 31, 2015 and 2014, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $444 million and $553 million at December 31, 2015 and 2014, respectively. The fair value of these plans' assets was approximately $121 million and $145 million at December 31, 2015 and 2014, respectively.

Plan Assets. The investment policies and strategies for the assets of each of the pension and OPEB plans are established by the Fiduciary Committee (the "Committee"), which is responsible for investment decisions and management oversight of each plan. The stated philosophy of the Committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the Committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the Committee has adopted a strategy of using multiple asset classes.

As of December 31, 2015, the allowable range for asset allocations in effect for the pension plan were 34% to 59% equity, 37% to 57% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock). As of December 31, 2015, the allowable range for asset allocations in effect for the retiree medical and retiree life insurance plans were 15% to 56% equity, 15% to 47% fixed income, 0% to 19% cash and 13% to 38% master limited partnerships.

In 2015, we adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) — Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)." This ASU removes the requirement to include investments in the fair value hierarchy for which the fair value is measured at Net Asset Value (NAV) using the practical expedient under Topic 820. Below are the details of our pension and OPEB plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this level are cash, common and preferred stock, exchange traded mutual funds and limited partnerships. These investments are valued at the closing price reported on the active market on which the individual securities are traded.

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are money market funds and fixed income securities. Money market funds are valued at amortized cost, which approximates fair value. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market.

- Level 3 assets' fair values are calculated using valuation techniques that require inputs that are both significant to the fair value measurement and are unobservable, or are similar to Level 2 assets. Included in this level are insurance contracts and interest rate swaps. Insurance contracts are valued at contract value, which approximates fair value.

- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include common/collective trust funds, equity trusts, mutual funds, limited partnerships, private equity and fixed income trusts. These amounts are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2015 and 2014 (in millions):

	Pension Assets							
	2015				2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash and money market funds	$15	$110	$—	$125	$5	$91	$—	$96
Insurance contracts	—	—	15	15	—	—	15	15
Mutual funds(a)	70	—	—	70	71	—	—	71
Common and preferred stocks(b)	271	—	—	271	459	—	—	459
Corporate bonds	—	244	—	244	—	247	—	247
U.S. government securities	—	171	—	171	—	190	—	190
Asset backed securities	—	34	—	34	—	28	—	28
Other	—	—	(14)	(14)	—	—	(15)	(15)
Subtotal	$356	$559	$1	916	$535	$556	$—	1,091
Measured at NAV(c)								
Common/collective trusts(d)				775				863
Equity trusts				187				199
Mutual funds(e)				160				198
Limited partnerships(f)				1				13
Private equity(g)				11				13
Subtotal				1,134				1,286
Total plan assets fair value				$2,050				$2,377

(a) For 2015 and 2014, this category includes mutual funds which are invested in equity.
(b) Plan assets include $91 million and $252 million of KMI Class P common stock for 2015 and 2014, respectively.
(c) Plan assets for which fair value was measured using NAV as a practical expedient.
(d) Common/collective trust funds were invested in approximately 45% fixed income and 55% equity in 2015 and 47% fixed income and 53% equity in 2014.
(e) Mutual funds were invested in fixed income for 2015 and 2014.

(f) Limited partnerships were invested in real estate partnerships for 2015 and 2014.
(g) Private equity was invested in limited partnerships that primarily invest in venture and buyout funds for 2015 and 2014.

	OPEB Assets							
	2015				2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash and money market funds	$—	$16	$—	$16	$(3)	$26	$—	$23
Domestic equity securities	8	—	—	8	14	—	—	14
Limited partnerships	51	—	—	51	87	—	—	87
Insurance contracts	—	—	49	49	—	—	51	51
Mutual funds	1	—	—	1	1	—	—	1
Subtotal	$60	$16	$49	125	$99	$26	$51	176
Measured at NAV(a)								
Common/collective trusts(b)				71				71
Fixed income trusts				58				63
Limited partnerships(c)				71				79
Subtotal				200				213
Total plan assets fair value				$325				$389

(a) Plan assets for which fair value was measured using NAV as a practical expedient.
(b) For 2015 and 2014, this category includes common/collective trust funds which are invested in approximately 67% equity and 33% fixed income securities, respectively.
(c) For 2015 and 2014, limited partnerships were invested in global equity securities.

The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2015 and 2014 (in millions):

	Pension Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2015					
Insurance contracts	$15	$—	$—	$—	$15
Other	(15)	—	(2)	3	(14)
Total	$—	$—	$(2)	$3	$1
2014					
Insurance contracts	$15	$—	$—	$—	$15
Other	11	—	(18)	(8)	(15)
Total	$26	$—	$(18)	$(8)	$—

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2015					
Insurance contracts	$51	$—	$(1)	$(1)	$49
2014					
Insurance contracts	$50	$—	$(4)	$5	$51

Changes in the underlying value of Level 3 assets due to the effect of changes of fair value were immaterial for the years ended December 31, 2015 and 2014.

Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2015, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2016	$230	$39
2017	197	39
2018	196	39
2019	198	39
2020	197	38
2021-2025	962	182

(a) Includes a reduction of approximately $3 million in each of the years 2016 - 2020 and approximately $18 million in aggregate for 2021 - 2025 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

We do not have any statutory funding requirements in 2016 for our pension plan; however, we may decide to make a contribution in 2016 depending on the market performance of our pension plan assets and other factors. In 2016, we expect to contribute approximately $14 million, net of anticipated subsidies, to our OPEB plan.

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2015, 2014 and 2013:

	Pension Benefits			OPEB		
	2015	2014	2013	2015	2014	2013
Assumptions related to benefit obligations:						
Discount rate	4.05 %	3.66 %	4.45 %	3.91 %	3.56 %	4.34 %
Rate of compensation increase	3.50 %	4.50 %	3.50 %	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate(a)	3.66 %	4.45 %	3.40 %	3.56 %	4.34 %	3.62 %
Expected return on plan assets(b)	7.50 %	7.50 %	8.00 %	7.08 %	7.43 %	7.35 %
Rate of compensation increase	4.50 %	3.50 %	3.00 %	n/a	n/a	n/a

(a) The discount rate related to other postretirement benefit cost was 3.34% for the period from January 1, 2013 to July 31, 2013 (the period prior to an OPEB plan amendment that resulted in a remeasurement) and 4.00% for the period from August 1, 2013 to December 31, 2013.

(b)

The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the OPEB assets subject to unrelated business income taxes (UBIT), we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on a UBIT rate of 21% for both 2015 and 2014 and 24% for 2013.

For 2015, we selected our discount rates by matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities. Effective January 1, 2016, we changed our estimate of the service and interest cost components of net periodic benefit cost (credit) for our pension and other postretirement benefit plans. The new estimate utilizes a full yield curve approach in the estimation of these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The new estimate provides a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows and their corresponding spot rates. The change does not affect the measurement of our pension and postretirement benefit obligations and it is accounted for as a change in accounting estimate, which is applied prospectively. The change in the service and interest costs going forward will not be significant. The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita cost of covered health care benefits of 9.89%, gradually decreasing to 4.54% by the year 2038. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2015 and 2014 (in millions):

	2015	2014
One-percentage point increase:		
Aggregate of service cost and interest cost	$2	$2
Accumulated postretirement benefit obligation	31	47
One-percentage point decrease:		
Aggregate of service cost and interest cost	$(1)	$(2)
Accumulated postretirement benefit obligation	(27)	(40)

Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows (in millions):

	Pension Benefits			OPEB		
	2015	2014	2013	2015	2014	2013
Components of net benefit cost:						
Service cost	$33	$21	$25	$—	$—	$—
Interest cost	99	112	92	21	25	23
Expected return on assets	(172)	(171)	(175)	(23)	(24)	(22)
Amortization of prior service credit	—	—	—	(3)	(2)	(1)
Amortization of net actuarial loss (gain)	5	—	—	1	(1)	3
Curtailment and settlement gain	—	—	(3)	—	—	—
Net benefit (credit) cost	(35)	(38)	(61)	(4)	(2)	3
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net loss (gain) arising during period	267	285	(211)	(49)	10	(50)
Prior service cost (credit) arising during period	—	—	25	—	—	(18)
Amortization or settlement recognition of net actuarial (loss) gain	(5)	—	3	(1)	—	(3)
Amortization of prior service credit	—	—	—	1	1	1
Total recognized in total other comprehensive (income) loss	262	285	(183)	(49)	11	(70)
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	$227	$247	$(244)	$(53)	$9	$(67)

Other Plans

Plans Associated with Foreign Operations

Two of our subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension plans for eligible Trans Mountain pipeline system employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements (which provide pension benefits in excess of statutory limits) and defined contributory plans. These subsidiaries also provide postretirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and other postretirement benefit plans for the years ended December 31, 2015, 2014 and 2013 was $12 million, $10 million and $11 million, respectively, recognized ratably over each year. As of December 31, 2015, we estimate the overall net periodic pension and other postretirement benefit costs for these plans for the year 2016 will be approximately $10 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. Furthermore, we expect to contribute approximately $10 million to these benefit plans in 2016.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily the acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, we participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately $10 million, $13 million and $11 million for the years ended December 31, 2015, 2014 and 2013, respectively. We consider the overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

11. Stockholders' Equity

Common Equity

As of December 31, 2015, our common equity consisted of our Class P common stock.

During the years 2013 through 2015, as authorized by our board of directors under various repurchase programs, we repurchased shares and warrants. As of December 31, 2015, we had $90 million of availability to repurchase warrants. During the years ended December 31, 2015, 2014 and 2013, we paid a total of $12 million, $98 million and $465 million, respectively, for the repurchase of warrants. During the years ended December 31, 2014 and 2013, we repurchased $94 million and $172 million respectively, of our Class P shares.

On December 19, 2014, we entered into an equity distribution agreement authorizing us to issue and sell through or to the managers party thereto, as sales agents and/or principals, shares of our Class P common stock having an aggregate offering of up to $5.0 billion from time to time during the term of this agreement. During the year ended December 31, 2015, we issued and sold 102,614,508 shares of our Class P common stock pursuant to the equity distribution agreement resulting in net proceeds of $3.9 billion.

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:

	Year Ended December 31,		
	2015	2014	2013
Per common share cash dividend declared for the period	$1.605	$1.740	$1.600
Per common share cash dividend paid in the period	1.93	1.70	1.56

On January 20, 2016, our board of directors declared a cash dividend of $0.125 per common share for the quarterly period ended December 31, 2015, which is payable on February 16, 2016 to shareholders of record as of February 1, 2016.

Warrants

Each of our warrants 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 table below sets forth the changes in our outstanding warrants:

	Warrants		
	2015	2014	2013
Beginning balance	298,135,976	347,933,107	439,809,442
Warrants issued in acquisition of EP(a)	—	—	81
Warrants issued with conversions of EP Trust I Preferred securities(b)	1,293,615	4,315	118,377
Warrants exercised	(71,268)	(18,040)	(21,208)
Warrants repurchased and canceled	(6,094,526)	(49,783,406)	(91,973,585)
Ending balance	293,263,797	298,135,976	347,933,107

(a) 2013 amount represents warrants issued upon the settlement of an EP dissenter. The settlement of the dissenter's 128 EP shares was determined based on the same conversion of EP shares into cash, KMI Class P shares and KMI warrants that was received by other EP shareholders at the time of the acquisition.

(b) See Note 9.

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 9.75% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share (equal to a $50 liquidation preference per depositary share). Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1,541 million. The proceeds from the offering were used to repay borrowings under our revolving credit facility and commercial paper debt and for general corporate purposes.

Unless converted earlier at the option of the holders, on or around October 26, 2018, each share of convertible preferred stock will automatically convert into between 30.8800 and 36.2840 shares of our common stock (and, correspondingly, each depositary share will convert into between 1.5440 and 1.8142 shares of our common stock), subject to customary anti-dilution adjustments. The conversion range depends on the volume-weighted average price of our common stock over a 20 trading day averaging period immediately prior to that date (Applicable Market Value). If the Applicable Market Value for our common stock is greater than $32.38 or less than $27.56, the conversion rate per preferred stock will be 30.8800 or 36.2840, respectively. If the Applicable Market Value is between $32.38 and $27.56, the conversion rate per preferred stock will be between 30.8800 and 36.2840.

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 9.75% 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.

On November 17, 2015, our board of directors declared a cash dividend of $23.291667 per share of our mandatory convertible preferred stock (equivalent of $1.164583 per depository share) for the period from and including October 30, 2015 through and including January 25, 2016, which was paid on January 26, 2016 to mandatory convertible preferred shareholders of record as of January 11, 2016.

Noncontrolling Interests

Contributions

Prior to the completion of the Merger Transactions on November 26, 2014, contributions from our noncontrolling interests consisted primarily of equity issuances to the public of common units or shares by KMP, EPB and KMR. Each of these subsidiaries had an equity distribution agreement in place which allowed the subsidiary to sell its equity interests from time to time through a designated sales agent. The equity distribution agreement provided the subsidiary with the right, but not the obligation to offer and sell its equity units or shares, at prices to be determined by market conditions. For the periods ended November 26, 2014 and December 31, 2013, KMP, EPB and KMR made equity issuances of 30 million and 63 million units or shares, respectively, resulting in net proceeds of $1,695 million and $1,580 million, respectively. These equity issuances during the periods ended November 26, 2014 and December 31, 2013 had the associated effects of increasing our (i) noncontrolling interests by $1,640 million and $5,059 million, respectively; (ii) accumulated deferred income taxes by $19 million and $93 million, respectively; and (iii) additional paid-in capital by $36 million and $161 million, respectively.

Distributions

The following table provides information about distributions from our noncontrolling interests (in millions except per unit and i-unit distribution amounts):

	Year Ended December 31,	
	2014	2013
KMP(a)		
Per unit cash distribution declared for the period	$4.17	$5.33
Per unit cash distribution paid in the period	$5.53	$5.26
Cash distributions paid in the period to the public	$1,654	$1,372
EPB(a)		
Per unit cash distribution declared for the period	$1.95	$2.55
Per unit cash distribution paid in the period	$2.60	$2.51
Cash distributions paid in the period to the public	$347	$318
KMR(a)(b)		
Share distributions paid in the period to the public	7,794,183	6,588,477

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(a) As a result of the Merger Transactions, no distribution was declared starting with the fourth quarter of 2014.

(b) KMR's distributions were paid in the form of additional shares or fractions thereof calculated by dividing the KMP cash distribution per common unit by the average of the market closing prices of a KMR share determined for a ten-trading day period ending on the trading day immediately prior to the ex-dividend date for the shares. Represents share distributions made in the period to noncontrolling interests and excludes 1,127,712 and 976,723 of shares distributed in 2014 and 2013, respectively, on KMR shares we directly and indirectly owned.

12. Related Party Transactions

Affiliate Balances

The following tables summarize our affiliate balance sheet balances and income statement activity (in millions):

	December 31,	
	2015	2014
Balance sheet location		
Accounts receivable, net	$25	$31
Other current assets	36	3
Deferred charges and other assets	—	46
	$61	$80
Current portion of debt(a)	$6	$6
Accounts payable	22	22
Other current liabilities	10	—
Long-term debt(a)	167	172
	$205	$200

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(a) Includes financing obligations payable to WYCO (See Note 9).

	Year Ended December 31,		
	2015	2014	2013
Income statement location			
Services	$72	$29	$31
Product sales and other	71	86	36
	$143	$115	$67
Cost of sales	$60	$74	$17
General and administrative	55	57	57

Notes Receivable

Plantation
We and ExxonMobil Corporation have a term loan agreement covering a note receivable due from Plantation. We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was $35 million and $47 million as of December 31, 2015 and 2014, respectively. The note bears interest at the rate of 4.25% per annum and provides for semiannual payments of principal and interest on December 31 and June 30 each year, with a final principal payment for our remaining portion of the note due on July 20, 2016. We included $35 million and $1 million of the note receivable balance within “Other current assets” on our accompanying balance sheets as of December 31, 2015 and 2014, respectively, and we included $46 million as of December 31, 2014 within “Deferred charges and other assets.”
Subsequent Event

MEP Loan Agreement

On February 3, 2016 we renewed our loan agreement for an additional one-year term with MEP, our 50%-owned equity investee. The loan agreement allows us, at our sole option, to make loans from time to time to MEP to fund its working capital needs and for other LLC purposes. Each individual loan must be in an amount not less than $2 million, and the aggregate loan balance outstanding must not exceed $40 million. Borrowings under the loan agreement bear interest at a rate of one month LIBOR plus 1.50%, and all borrowings can be prepaid before maturity without penalty or premium. As of both December 31, 2015 and 2014 there was no amount outstanding pursuant to this loan agreement.

13. Commitments and Contingent Liabilities

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2015 (in millions):

Year	Commitment
2016	$103
2017	90
2018	83
2019	78
2020	69
Thereafter	406
Total minimum payments	$829

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to forty years. Total lease and rental expenses were $143 million, $114 million and $126 million for the years ended

December 31, 2015, 2014 and 2013, respectively. The amount of capital leases included within “Property, plant and equipment, net” in our accompanying consolidated balance sheets as of December 31, 2015 and 2014 is not material to our consolidated balance sheets.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2015 and 2014, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $1,202 million and $1,069 million, respectively. Both December 31, 2015 and 2014 amounts are primarily represented by our proportional share of the debt obligations of two equity investees. Under such guarantees we are severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. Also included in our contingent debt obligations is a guarantee of the debt obligations of our 50%-owned investee, Cortez Pipeline Company (we are severally liable for its percentage ownership share (50%) of the Cortez Pipeline Company debt and 100% of the debt issued by one of its subsidiaries in the event of their non-performance) which has a $200 million credit facility and $120 million private placement note to fund an expansion project.

Guarantees and Indemnifications

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are also circumstances where the amount and duration are unlimited. Currently, we are not subject to any material requirements to perform under quantifiable arrangements, and we expect future requirements to perform under quantifiable arrangements will be immaterial. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

See Note 17 "Litigation, Environmental and Other Contingencies" for a description of matters that we have identified as contingencies requiring accrual of liabilities and/or disclosure, including any such matters arising under guarantee or indemnification agreements.

Commitment for Jones Act Trade Fleet Expansion

In August 2015, we entered into a definitive agreement with Philly Tankers LLC totaling $568 million for the construction of four new Tier II, LNG-conversion-ready tankers each with a capacity of 337 MBbl. The tankers are expected to be delivered between November 2016 and November 2017 and would increase our Jones Act tanker fleet to 16 ships by late 2017. Our obligation for payments due under the terms of this agreement total $170 million in 2016 and $384 million in 2017.

14. 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, we have power forward and swap contracts related to legacy operations of acquired businesses for which we entered into positions that offset the price risks associated with these contracts.

As of December 31, 2014, we discontinued hedge accounting on certain of our crude derivative contracts as we did not expect them to continue to be highly effective, for accounting purposes, in offsetting the variability in cash flows. This was caused primarily by volatility in basis differentials. As the forecasted transactions are still probable, accumulated gains and losses remain in other comprehensive income until earnings are impacted by the forecasted transactions. Changes in the derivative contracts' fair value subsequent to the discontinuance of hedge accounting are reported in earnings. As of December 31, 2015, all of these hedging relationships had been re-designated as the effectiveness improved to required levels.

Energy Commodity Price Risk Management

As of December 31, 2015, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(21.7	) MMBbl
Crude oil basis	(6.4	) MMBbl
Natural gas fixed price	(37.6	) Bcf
Natural gas basis	(30.1	) Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(0.6	) MMBbl
Crude oil basis	(1.3	) MMBbl
Natural gas fixed price	(14.3	) Bcf
Natural gas basis	(8.6	) Bcf
NGL and other fixed price	(1.9	) MMBbl

As of December 31, 2015, 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 2019.

Interest Rate Risk Management

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. As of December 31, 2014, we had a combined notional principal amount of $9,200 million of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of December 31, 2015, 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.

In December 2015, we entered into nine separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $1,300 million. These agreements effectively convert a portion of the interest expense associated with our 4.15% senior notes due February 2, 2024, 3.50% senior notes due September 1, 2023 and 4.30% senior notes due May 1, 2024, from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread.

Foreign Currency Risk Management

In connection with the issuance of our Euro denominated senior notes in March 2015 (see Note 9), 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 on our accompanying consolidated balance sheets (in millions):
Fair Value of Derivative Contracts

		Asset derivatives December 31,		Liability derivatives December 31,	
		2015	2014	2015	2014
	Location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$359	$309	$(13)	$(34)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	244	6	—	—
Subtotal		603	315	(13)	(34)
Interest rate swap agreements	Fair value of derivative contracts/(Other current liabilities)	111	143	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	273	260	(9)	(53)
Subtotal		384	403	(9)	(53)
Cross-currency swap agreements	Fair value of derivative contracts/(Other current liabilities)	—	—	(6)	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	(46)	—
Subtotal		—	—	(52)	—
Total		987	718	(74)	(87)
Derivatives not designated as hedging contracts					
Natural gas, crude, NGL and other derivative contracts	Fair value of derivative contracts/(Other current liabilities)	35	73	(1)	(2)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	196	—	—
Subtotal		35	269	(1)	(2)
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		1	10	(17)	(57)

	Fair value of derivative contracts/(Other current liabilities)				
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	—	(16)
Subtotal		1	10	(17)	(73)
Total		37	279	(34)	(75)
Total derivatives		$1,024	$997	$(108)	$(162)

126

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 Year Ended December 31,		
		2015	2014	2013
Interest rate swap agreements	Interest, net	$25	$207	$(425)
Hedged fixed rate debt	Interest, net	$(33)	$(204)	$425

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)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2015	2014	2013		2015	2014	2013		2015	2014	2013
Energy commodity derivative contracts	$201	$424	$(45)	Revenues—Natural gas sales	$54	$(1)	$—	Revenues—Natural gas sales	$—	$—	$—
				Revenues—Product sales and other	236	26	(13)	Revenues—Product sales and other	2	11	3
				Costs of sales	(15)	4	—	Costs of sales	—	—	—
Interest rate swap agreements(c)	(4)	(15)	7	Interest, net	(3)	(4)	2	Interest, net	—	—	—
Cross-currency swap	(33)	—	—	Other, net	—	—	—	Other, net	—	—	—
Total	$164	$409	$(38)	Total	$272	$25	$(11)	Total	$2	$11	$3

(a) We expect to reclassify an approximate $181 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balances as of December 31, 2015 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 income/(loss).

127

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives		
		Year Ended December 31,		
		2015	2014	2013
Energy commodity derivative contracts	Revenues—Natural gas sales	$ 17	$ (7)	$ —
	Revenues—Product sales and other	176	20	(10)
	Costs of sales	(2)	—	2
	Other expense (income)	—	(2)	(2)
Interest rate swap agreements	Interest, net	(15)	—	—
Total(a)		$ 176	$ 11	$ (10)

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(a) For the year ended December 31, 2015, includes approximate gain of $31 million 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 December 31, 2015 and 2014, we had $2 million and $20 million, respectively, of outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2015 and December 31, 2014, we had no cash margin and $47 million posted by us with our counterparties as collateral and $37 million and $13 million, respectively, held by us as collateral from our counterparties.

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 December 31, 2015, based on our current mark to market positions and posted collateral, we estimate that if our credit rating was downgraded one or two notches, we would be required to post $1 million and $4 million, respectively, of 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, 2012	$7	$51	$(176)	$(118)
Other comprehensive income before reclassifications	(14)	(49)	151	88
Amounts reclassified from accumulated other comprehensive loss	4	—	2	6
Net current-period other comprehensive income	(10)	(49)	153	94
Balance as of December 31, 2013	(3)	2	(23)	(24)
Other comprehensive loss before reclassifications	254	(68)	(212)	(26)
Amounts reclassified from accumulated other comprehensive loss	(22)	—	(1)	(23)
Impact of Merger Transactions (See Note 1)	98	(42)	—	56
Net current-period other comprehensive income	330	(110)	(213)	7
Balance as of December 31, 2014	327	(108)	(236)	(17)
Other comprehensive loss before reclassifications	164	(214)	(122)	(172)
Amounts reclassified from accumulated other comprehensive loss	(272)	—	—	(272)
Net current-period other comprehensive loss	(108)	(214)	(122)	(444)
Balance as of December 31, 2015	$219	$(322)	$(358)	$(461)

15. Fair Value

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

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

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

Fair Value of Derivative Contracts

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

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of 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	$—	$—	$—	$—	$—	$—	$—
As of December 31, 2014							
Energy commodity derivative contracts(a)	$49	$533	$12	$594	$(46)	$(13)	$535
Interest rate swap agreements	$—	$403	$—	$403	$(44)	$—	$359

	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 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)
As of December 31, 2014							
Energy commodity derivative contracts(a)	$(25)	$(11)	$(73)	$(109)	$46	$47	$(16)
Interest rate swap agreements	$—	$(53)	$—	$(53)	$44	$—	$(9)

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI 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 “Other current assets” 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)

	Year Ended December 31,	
	2015	2014
Derivatives-net asset (liability)		
Beginning of period	$(61)	$(110)
Transfers out(a)	—	(88)
Total gains or (losses)		
Included in earnings	(13)	22
Included in other comprehensive loss	—	78
Settlements	59	37
End of period	$(15)	$(61)
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	$—	$1

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(a) On December 31, 2014, we transferred WTI options from Level 3 to Level 2 due to increased observability of significant inputs in their valuations.

As of December 31, 2015, our Level 3 derivative assets and liabilities consisted primarily of power derivative contracts, 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.

Fair Value of Financial Instruments

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

	December 31, 2015		December 31, 2014	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$43,227	$37,481	$42,814	$43,761

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2015 and 2014.

16. Reportable Segments

We divide our operations into the following reportable business segments. These segments and their principal sources of revenues are as follows:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium for recovering crude oil from mature oil fields to increase production; (ii) ownership interests in and/or operation of oil fields and gas processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—(i) the ownership and/or operation of liquids and bulk terminal facilities located throughout the U.S. and portions of Canada that transload and store refined petroleum products, crude oil, condensate, and bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals and (ii) the ownership and operation of our Jones Act tankers;

- Products Pipelines—the ownership and operation of refined petroleum products and crude oil and condensate pipelines that deliver refined petroleum products (gasoline, diesel fuel and jet fuel), NGL, crude oil, condensate and bio-fuels to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Kinder Morgan Canada—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington, plus the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport; and

- Other—primarily other miscellaneous assets and liabilities including (i) our corporate headquarters in Houston, Texas; (ii) several physical natural gas contracts with power plants associated with legacy trading activities; and (iii) other miscellaneous assets and liabilities.

We evaluate performance principally based on each segment's EBDA (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income, and unallocable income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

During 2015, 2014 and 2013, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2015	2014	2013
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$8,704	$10,153	$8,613
Intersegment revenues	21	15	4
CO_2	1,699	1,960	1,857
Terminals			
Revenues from external customers	1,878	1,717	1,408
Intersegment revenues	1	1	2
Products Pipelines			
Revenues from external customers	1,828	2,068	1,853
Intersegment revenues	3	—	—
Kinder Morgan Canada	260	291	302
Other	(3)	1	1
Total segment revenues	14,391	16,206	14,040
Other revenues(a)	37	36	36
Less: Total intersegment revenues	(25)	(16)	(6)
Total consolidated revenues	$14,403	$16,226	$14,070

	Year Ended December 31,		
	2015	2014	2013
Operating expenses(b)			
Natural Gas Pipelines	$4,738	$6,241	$5,235
CO_2	432	494	439
Terminals	836	746	657
Products Pipelines	772	1,258	1,295
Kinder Morgan Canada	87	106	110
Other	51	24	30
Total segment operating expenses	6,916	8,869	7,766
Less: Total intersegment operating expenses	(25)	(16)	(6)
Total consolidated operating expenses	$6,891	$8,853	$7,760

	Year Ended December 31,		
	2015	2014	2013
Other expense (income)(c)			
Natural Gas Pipelines	$1,269	$5	$(24)
CO_2	606	243	—
Terminals	190	29	(74)
Products Pipelines	2	(3)	6
Kinder Morgan Canada	(1)	—	—
Other	—	1	(7)
Total consolidated other expense (income)	$2,066	$275	$(99)

	Year Ended December 31,		
	2015	2014	2013
DD&A			
Natural Gas Pipelines	$1,046	$897	$797
CO_2	556	570	533
Terminals	433	337	247
Products Pipelines	206	166	155
Kinder Morgan Canada	46	51	54
Other	22	19	20
Total consolidated DD&A	$2,309	$2,040	$1,806

	Year Ended December 31,		
	2015	2014	2013
Earnings from equity investments and amortization of excess cost of equity investments, including loss on impairments			
Natural Gas Pipelines	$285	$279	$200
CO_2	(5)	26	22
Terminals	17	18	22
Products Pipelines	36	37	40
Kinder Morgan Canada	—	—	4
Other	—	1	—
Total consolidated equity earnings	$333	$361	$288

	Year Ended December 31,		
	2015	2014	2013
Interest income			
Natural Gas Pipelines	$—	$1	$—
Products Pipelines	2	2	2
Kinder Morgan Canada	—	—	3
Other	2	6	8
Total segment interest income	4	9	13
Unallocated interest income	—	—	2
Total consolidated interest income	$4	$9	$15

	Year Ended December 31,		
	2015	2014	2013
Other, net-income (expense)			
Natural Gas Pipelines	$24	$24	$578
CO_2	—	—	—
Terminals	8	12	1
Products Pipelines	4	(1)	1
Kinder Morgan Canada	8	15	246
Other	(1)	30	9
Total consolidated other, net-income (expense)	$43	$80	$835

	Year Ended December 31,		
	2015	2014	2013
Income tax benefit (expense)			
Natural Gas Pipelines	$(4)	$(6)	$(9)
CO_2	(1)	(8)	(7)
Terminals	(29)	(29)	(14)
Products Pipelines	(8)	(2)	2
Kinder Morgan Canada	(19)	(18)	(21)
Total segment income tax expense	(61)	(63)	(49)
Unallocated income tax expense	(503)	(585)	(693)
Total consolidated income tax expense	$(564)	$(648)	$(742)

	Year Ended December 31,		
	2015	2014	2013
Segment EBDA(d)			
Natural Gas Pipelines	$3,063	$4,259	$4,207
CO_2	657	1,240	1,435
Terminals	849	944	836
Products Pipelines	1,100	856	602
Kinder Morgan Canada	163	182	424
Other	(53)	13	(5)
Total segment EBDA	5,779	7,494	7,499
Total segment DD&A	(2,309)	(2,040)	(1,806)
Total segment amortization of excess cost of equity investments	(51)	(45)	(39)
Other revenues	37	36	36
General and administrative expenses	(690)	(610)	(613)
Interest expense, net of unallocable interest income(e)	(2,055)	(1,807)	(1,688)
Unallocable income tax expense	(503)	(585)	(693)
Loss from discontinued operations, net of tax	—	—	(4)
Total consolidated net income	$208	$2,443	$2,692

	Year Ended December 31,		
	2015	2014	2013
Capital expenditures			
Natural Gas Pipelines	$1,642	$935	$1,085
CO_2	725	792	667
Terminals	847	1,049	1,108
Products Pipelines	524	680	416
Kinder Morgan Canada	142	156	77
Other	16	5	16
Total consolidated capital expenditures	$3,896	$3,617	$3,369

	2015	2014
Investments at December 31		
Natural Gas Pipelines	$5,080	$5,174
CO_2	—	17
Terminals	306	219
Products Pipelines	641	624
Kinder Morgan Canada	10	1
Other	3	1
Total consolidated investments	$6,040	$6,036

	2015	2014
Assets at December 31		
Natural Gas Pipelines	$53,704	$52,532
CO_2	4,706	5,227
Terminals	9,083	8,850
Products Pipelines	8,464	7,179
Kinder Morgan Canada	1,434	1,593
Other	418	455
Total segment assets	77,809	75,836
Corporate assets(f)	6,276	7,157
Assets held for sale	19	56
Total consolidated assets	$84,104	$83,049

(a) Includes a management fee for services we perform for NGPL.

(b) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(c) Includes loss on impairment of goodwill, loss (gain) on impairments and disposals of long-lived assets, net and other expense (income), net.

(d) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income), net, loss on impairment of goodwill, and losses (gain) on impairments and disposals of long-lived assets, net and equity investments.

(e) Includes (i) interest expense and (ii) miscellaneous other income and expenses not allocated to business segments.

(f) Includes cash and cash equivalents, margin and restricted deposits, unallocable interest receivable, prepaid assets and deferred charges, 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.

We do not attribute interest and debt expense to any of our reportable business segments.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2015	2014	2013
Revenues from external customers			
U.S.	$13,797	$15,605	$13,656
Canada	479	437	398
Mexico	127	184	16
Total consolidated revenues from external customers	$14,403	$16,226	$14,070

	December 31, 2015	2014
Long-term assets, excluding goodwill and other intangibles		
U.S.	$51,679	$49,992
Canada	2,193	2,268
Mexico	67	81
Total consolidated long-lived assets	$53,939	$52,341

17. 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 are successful in proving these claims or other of their claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing 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. 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 $160 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 several recent FERC decisions in SFPP cases, as applicable, to pending 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. 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) on October 17, 2013. EPNG sought rehearing on certain issues in Opinion 528. As required by Opinion 528, EPNG filed revised pro forma recalculated rates consistent with the terms of Opinion 528. The FERC also required an Administrative Law Judge (ALJ) to conduct an additional hearing concerning one of the issues in Opinion 528. On September 17, 2014, the ALJ issued an initial decision finding certain shippers qualify for lower rates under a prior settlement. EPNG has sought FERC review of the ALJ decision. EPNG believes it has an appropriate reserve, which is classified as a current liability, related to the findings in Opinions 517-A and 528 for both rate cases.

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 liability, 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.

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 and disputed its indemnity obligation. 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 will file an appeal to the Delaware Supreme Court and 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. Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that 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 the Merger Transactions, which the Court consolidated under the caption In re Kinder Morgan, Inc. Corporate Reorganization Litigation (Consolidated Case No. 10093-VCL). The plaintiffs originally sought to enjoin one or more of the proposed Merger Transactions, which relief the Court denied on November 5, 2014. On December 12, 2014, the plaintiffs filed a Verified Second Consolidated Amended Class Action Complaint, which purports 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 allege 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 seeks 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). The plaintiffs are only appealing the dismissal of claims brought against defendants KMGP, Ted A. Gardner, Gary L. Hultquist, and Perry M. Waughtal and not those asserted against KMI, P. Merger Sub LLC, Richard D. Kinder, Steven J. Kean, KMP and KMR. The Supreme Court will hear oral argument on March 9, 2016. The defendants believe the allegations against them lack merit, and they intend to vigorously defend the lawsuit.

Kinder Morgan Energy Partners, L.P. Capex Litigation

Putative class action and derivative complaints were filed in the Court of Chancery in the State of Delaware against defendants KMI, KMGP and nominal defendant KMEP on February 5, 2014 and March 27, 2014 captioned Slotoroff v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al (Case No. 9318) and Burns et al v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al (Case No. 9479) respectively. The cases were consolidated on April 8, 2014 (Consolidated Case No. 9318). The consolidated suit asserted claims both individually and on behalf of a putative class consisting of all public holders of KMEP units during the period of February 5, 2011 through the date of the filing of the complaints. The suit alleged direct and derivative causes of action for breach of the partnership agreement, breach of the duty of good faith and fair dealing, aiding and abetting, and tortious interference. Among other things, the suit alleged that defendants made a bad faith allocation of capital expenditures to expansion capital expenditures rather than maintenance capital expenditures for the alleged purpose of "artificially" inflating KMEP's distributions and growth rate. The suit alleged that hundreds of millions of dollars were distributed improperly and sought disgorgement of any distributions to KMGP, KMI and any related entities, beyond amounts that would have been distributed in accordance with a "good faith" allocation of maintenance capital expenses, together with other unspecified monetary damages including punitive damages and attorney fees.

On August 14, 2015, the parties entered into a Stipulation and Agreement of Settlement pursuant to which defendants paid $27.5 million (the "Settlement Fund") to a class of former holders of KMEP common units, and all claims asserted in the consolidated suit are released. Following notice to the putative class members, on December 22, 2015, the Court approved the settlement which also includes a release of all claims asserted in the Walker litigation discussed below, and awarded attorneys' fees and litigation expenses to Plaintiffs' counsel to be paid from the Settlement Fund. All of the defendants believe they acted properly, in good faith, and in a manner consistent with any and all legal, contractual and equitable duties and obligations, including those contained in the Limited Partnership Agreement. We entered into this settlement solely to avoid the substantial burden, expense, inconvenience and distraction of continued litigation and to resolve each of the released claims.

Walker v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc. et al.

On March 6, 2014, a putative class action and derivative complaint was filed in the District Court of Harris County, Texas (Case No. 2014-11872 in the 215th Judicial District) against KMI, KMGP, KMR, Richard D. Kinder, Steven J. Kean, Ted A. Gardner, Gary L. Hultquist, Perry M. Waughtal and nominal defendant KMEP. The suit was filed by Kenneth Walker, a purported unit holder of KMEP, and alleged derivative causes of action for alleged violation of duties owed under the partnership agreement, breach of the implied covenant of good faith and fair dealing, "abuse of control" and "gross mismanagement" in connection with the calculation of distributions and allocation of capital expenditures to expansion capital expenditures and maintenance capital expenditures. The suit sought unspecified money damages, interest, punitive damages, attorney and expert fees, costs and expenses, unspecified equitable relief, and demanded a trial by jury. On January 5, 2016, Plaintiffs filed a Notice of Nonsuit, with prejudice, which the Court subsequently granted, dismissing all claims in the action with prejudice.

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 December 31, 2015 and 2014, our total reserve for legal matters was $463 million and $400 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. The overall increase in the reserve from December 31, 2014 is related to certain legal developments during the year ended December 31, 2015 on 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 law 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. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or dividends to our shareholders.

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. Once the EPA determines the cleanup remedy from the remedial investigations and feasibility studies conducted during the last decade at the site, it will issue a Record of Decision (ROD). Currently, 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. We expect the RI/FS process to conclude in 2016. We expect EPA will publish a Proposed Remedial Action Plan by April 2016 leading to a final ROD targeted for late 2016 or early 2017. The allocation process will follow the issuance of the ROD with an expected completion date of 2018. We anticipate that the cleanup activities will begin within two years after the ROD is issued.

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 against 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.

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 is 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 January 25, 2016, the District Court heard oral argument on motions we previously filed to exclude certain expert testimony offered by the City and for partial summary judgment on the City's claims. By its Order dated February 2, 2016, the Court granted in part and denied in part our motion to exclude certain expert testimony, granted in part and denied in part our motion for partial summary judgment, found that the City is limited to seeking alleged damages relating to the three year period immediately preceding the filing of the lawsuit, found that the City lacks expert opinions or testimony to support its claim for water damages, including the alleged loss of use of the Mission Valley aquifer as a source of both supply and storage of potable water, and denied our motion for partial summary judgment on the City's alleged real estate and restoration damages. As a result of the Court's Order, the City's alleged damages will be reduced from approximately $365 million to approximately $160 million. Trial is scheduled to begin April 5, 2016. We intend to continue to vigorously defend the case.

This site remains under the regulatory oversight and order of the California Regional Water Quality Control Board (RWQCB). SFPP has 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. SFPP expects the RWQCB to issue a notice of no further action with respect to the stadium property site. 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 will conduct 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, subject to final judicial approval, 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 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. In its FFS, the EPA stated that it has identified over 100 industrial facilities as potentially responsible parties and it is likely that there are hundreds more private and public entities that could be named in any litigation concerning responsibility for the Site contamination.

No final remedy for this portion of the Site will be selected until the public comment and response period for the FFS is completed and the Record of Decision (ROD) is issued by the EPA, which is expected by March 31, 2016. Until the ROD is issued, there is uncertainty about what remedy will be implemented and the extent of potential costs. 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.

Philadelphia and Point Breeze Terminals, Notices of Violation

On August 7, 2015, KMLT's Philadelphia Terminal received a Notice of Violation (NOV) from the Pennsylvania Department of Environmental Protection (PADEP) related to an alleged ethanol release from an above ground storage tank at the facility. The NOV alleged a failure to investigate and confirm a suspected release within the regulatory time period and failure of emergency containment to contain a release from a tank. On July 30, 2015, KMLT's Point Breeze Terminal received a NOV from the PADEP relating to an alleged violation of a regulatory requirement to remove storm water from the emergency containment areas surrounding above ground storage tanks at the facility prior to capacity of containment being reduced by ten percent (10%) or more. Following an informal administrative hearing with the PADEP on October 14, 2015 with respect to both matters, the NOV related to the Philadelphia Terminal was settled for $570,000 and the NOV related to the Point Breeze Terminal was settled for $175,000.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC (CFPL) reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and no injuries associated with the incident. CFPL cleaned up the release in coordination with federal, state and local agencies. The cause of the incident was determined to be a third party line strike. In August 2015, the EPA requested that CFPL engage in settlement discussions regarding potential penalties sought by the EPA under the Clean Water Act up to the statutory maximum of approximately $0.9 million. Although CFPL does not believe it caused the incident, and is prepared to vigorously defend any claims that might be asserted by the EPA, we are engaging in good faith settlement negotiations as requested by the EPA.

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 will hear oral argument on February 29, 2016.

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. By the end of 2015, the Parish's legal counsel had not taken any action to dismiss the cases, and the defendants in the cases, including TGP in the instant case, filed motions to dismiss on the basis of the Parish Council's November 12, 2015 resolution. Those motions are pending.

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 December 31, 2015 and 2014, we have accrued a total reserve for environmental liabilities in the amount of $284 million and $340 million, respectively. In addition, as of December 31, 2015 and 2014, we have recorded a receivable of $13 million and $14 million, respectively, for expected cost recoveries that have been deemed probable.

18. Recent Accounting Pronouncements

Accounting Standards Updates

ASU No. 2014-09

On May 28, 2014, the FASB issued ASU No. 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 January 1, 2018. Early adoption is permitted for the interim periods within the adoption year. We are currently reviewing the effect of ASU No. 2014-09 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. ASU No. 2015-02 was effective January 1, 2016. We do not expect the effect of ASU No. 2015-02 to have a material impact on 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 January 1, 2017. We are currently reviewing the effect of ASU No. 2015-11.

19. Guarantee of Securities of Subsidiaries

KMI, along with its direct and indirect subsidiaries KMP, and Copano, are issuers of certain public debt securities. After the completion of the Merger Transactions, KMI, KMP, Copano and substantially all of KMI’s wholly owned domestic subsidiaries, entered into 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 issuers 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, KMP, or Copano are in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuers 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 each 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 issuers in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of December 31, 2015, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Issuer and Guarantor-Copano, and Subsidiary Guarantors had $13,346 million, $19,985 million, $332 million, and $6,882 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2015 condensed consolidating balance sheets are approximately $177 million of capitalized lease debt that is not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Issuer and Guarantor-Copano, 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.

On January 1, 2015, EPB and its subsidiary, EPPOC merged with and into KMP with KMP surviving the merger. As a result of such merger, all of the wholly owned subsidiaries of EPB became wholly owned subsidiaries of KMP and effective January 1, 2015, EPB is no longer a Subsidiary Issuer and Guarantor. The condensed consolidating financial information reflects this transaction for all periods presented below.

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total revenues	$ 37	$—	$—	$ 12,607	$ 1,808	$ (49)	$ 14,403
Operating costs, expenses and other							
Costs of sales	—	—	—	3,745	369	1	4,115
Depreciation, depletion and amortization	22	—	—	1,898	389	—	2,309
Other operating expenses	71	38	632	4,071	770	(50)	5,532
Total operating costs, expenses and other	93	38	632	9,714	1,528	(49)	11,956
Operating (loss) income	(56)	(38)	(632)	2,893	280	—	2,447
Other income (expense)							
Earnings (losses) from consolidated subsidiaries	1,430	1,643	68	307	(30)	(3,418)	—
Earnings from equity investments	—	—	—	384	—	—	384
Interest, net	(686)	23	(47)	(1,299)	(42)	—	(2,051)
Amortization of excess cost of equity investments and other, net	—	1	—	(17)	8	—	(8)
Income (loss) from continuing operations before income taxes	688	1,629	(611)	2,268	216	(3,418)	772
Income tax expense	(435)	(4)	—	(5)	(120)	—	(564)
Net income (loss)	253	1,625	(611)	2,263	96	(3,418)	208
Net loss attributable to noncontrolling interests	—	—	—	—	—	45	45
Net income (loss) attributable to controlling interests	253	1,625	(611)	2,263	96	(3,373)	253
Preferred stock dividends	(26)	—	—	—	—	—	(26)
Net income (loss) available to common stockholders	$ 227	$ 1,625	$ (611)	$ 2,263	$ 96	$ (3,373)	$ 227
Net income (loss)	$ 253	$ 1,625	$ (611)	$ 2,263	$ 96	$ (3,418)	$ 208

Total other comprehensive loss	(444)	(460)	—	(325)	(326)	1,111	(444)
Comprehensive (loss) income	(191)	1,165	(611)	1,938	(230)	(2,307)	(236)
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	—	45	45
Comprehensive (loss) income attributable to controlling interests	$ (191)	$ 1,165	$ (611)	$ 1,938	$ (230)	$ (2,262)	$ (191)

147

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total revenues	$ 36	$—	$—	$ 14,310	$ 1,886	$ (6)	$ 16,226
Operating costs, expenses and other							
Costs of sales	—	—	—	5,737	499	42	6,278
Depreciation, depletion and amortization	21	—	—	1,655	364	—	2,040
Other operating expenses	30	5	32	2,927	514	(48)	3,460
Total operating costs, expenses and other	51	5	32	10,319	1,377	(6)	11,778
Operating (loss) income	(15)	(5)	(32)	3,991	509	—	4,448
Other income (expense)							
Earnings from consolidated subsidiaries	2,080	3,977	224	664	1,120	(8,065)	—
Earnings from equity investments	—	—	—	407	(1)	—	406
Interest, net	(513)	(111)	(46)	(1,039)	(89)	—	(1,798)
Amortization of excess cost of equity investments and other, net	—	—	—	(13)	48	—	35
Income from continuing operations before income taxes	1,552	3,861	146	4,010	1,587	(8,065)	3,091
Income tax expense	(278)	(7)	—	(71)	(292)	—	(648)
Net income	1,274	3,854	146	3,939	1,295	(8,065)	2,443
Net income attributable to noncontrolling interests	(248)	(211)	—	—	—	(958)	(1,417)
Net income attributable to controlling interests	$ 1,026	$ 3,643	$ 146	$ 3,939	$ 1,295	$ (9,023)	$ 1,026
Net income	$ 1,274	$ 3,854	$ 146	$ 3,939	$ 1,295	$ (8,065)	$ 2,443
Total other comprehensive (loss) income	(24)	275	—	288	(168)	(351)	20
Comprehensive income	1,250	4,129	146	4,227	1,127	(8,416)	2,463
Comprehensive income attributable to noncontrolling interests	(273)	(203)	—	—	—	(1,010)	(1,486)

Comprehensive income attributable to controlling interests	$ 977	$ 3,926	$ 146	$ 4,227	$ 1,127	$ (9,426)	$ 977

148

Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2013
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total revenues	$ 36	$—	$—	$ 12,511	$ 1,512	$ 11	$ 14,070
Operating costs, expenses and other							
Costs of sales	—	—	—	4,739	468	46	5,253
Depreciation, depletion and amortization	20	—	—	1,466	320	—	1,806
Other operating expenses	22	8	38	2,325	663	(35)	3,021
Total operating costs, expenses and other	42	8	38	8,530	1,451	11	10,080
Operating (loss) income	(6)	(8)	(38)	3,981	61	—	3,990
Other income (expense)							
Earnings from consolidated subsidiaries	2,025	4,010	163	255	1,755	(8,208)	—
Earnings from equity investments	—	—	—	323	4	—	327
Interest, net	(539)	(100)	(36)	(965)	(35)	—	(1,675)
Amortization of excess cost of equity investments and other, net	(1)	—	(1)	549	249	—	796
Income from continuing operations before income taxes	1,479	3,902	88	4,143	2,034	(8,208)	3,438
Income tax (expense) benefit	(41)	(11)	—	50	(740)	—	(742)
Income from continuing operations	1,438	3,891	88	4,193	1,294	(8,208)	2,696
Loss from discontinued operations	—	—	—	(4)	—	—	(4)
Net income	1,438	3,891	88	4,189	1,294	(8,208)	2,692
Net income attributable to noncontrolling interests	(245)	(236)	—	—	—	(1,018)	(1,499)
Net income attributable to controlling interests	$ 1,193	$ 3,655	$ 88	$ 4,189	$ 1,294	$ (9,226)	$ 1,193
Net income	$ 1,438	$ 3,891	$ 88	$ 4,189	$ 1,294	$ (8,208)	$ 2,692

Total other comprehensive income (loss)	81	(135)	—	(99)	(172)	365	40
Comprehensive income	1,519	3,756	88	4,090	1,122	(7,843)	2,732
Comprehensive income attributable to noncontrolling interests	(232)	(237)	—	—	—	(976)	(1,445)
Comprehensive income attributable to controlling interests	$ 1,287	$ 3,519	$ 88	$ 4,090	$ 1,122	$ (8,819)	$ 1,287

Condensed Consolidating Balance Sheets as of December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	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	—	9,451	695	(13,979)	—
All other current assets	126	119	—	2,163	195	(8)	2,595
Property, plant and equipment, net	252	—	—	32,195	8,100	—	40,547
Investments	16	2	—	5,906	116	—	6,040
Investments in subsidiaries	27,401	28,038	2,341	4,361	3,320	(65,461)	—
Goodwill	15,089	22	287	5,221	3,171	—	23,790
Notes receivable from affiliates	850	21,319	—	2,070	380	(24,619)	—
Deferred income taxes	7,501	—	—	—	—	(2,178)	5,323
Other non-current assets	215	307	1	4,943	114	—	5,580
Total assets	$ 53,806	$ 51,407	$ 2,629	$ 66,322	$ 16,233	$ (106,293)	$ 84,104
LIABILITIES AND STOCKHOLDERS' EQUITY							
Liabilities							
Current portion of debt	$ 67	$ 500	$—	$ 132	$ 122	$ —	$ 821
Other current liabilities - affiliates	1,328	8,682	39	3,216	714	(13,979)	—
All other current liabilities	321	458	7	1,987	527	(56)	3,244
Long-term debt	13,845	20,053	378	7,447	683	—	42,406
Notes payable to affiliates	2,404	448	622	19,840	1,305	(24,619)	—
Deferred income taxes	—	—	2	594	1,582	(2,178)	—
Other long-term liabilities and deferred credits	722	193	—	907	408	—	2,230
Total liabilities	18,687	30,334	1,048	34,123	5,341	(40,832)	48,701
Stockholders' equity							
Total KMI equity	35,119	21,073	1,581	32,199	10,892	(65,745)	35,119
Noncontrolling interests	—	—	—	—	—	284	284
Total stockholders' equity	35,119	21,073	1,581	32,199	10,892	(65,461)	35,403
Total liabilities and stockholders' equity	$ 53,806	$ 51,407	$ 2,629	$ 66,322	$ 16,233	$ (106,293)	$ 84,104

Condensed Consolidating Balance Sheets as of December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS							
Cash and cash equivalents	$4	$15	$—	$17	$ 279	$ —	$ 315
Other current assets - affiliates	2,251	1,335	11	11,565	403	(15,565)	—
All other current assets	655	152	3	2,547	358	(278)	3,437
Property, plant and equipment, net	263	—	5	29,490	8,806	—	38,564
Investments	16	1	—	5,910	109	—	6,036
Investments in subsidiaries	25,286	33,414	1,911	4,628	3,337	(68,576)	—
Goodwill	15,087	22	920	5,419	3,206	—	24,654
Notes receivable from affiliates	522	19,832	—	2,415	496	(23,265)	—
Deferred income taxes	7,644	—	—	—	—	(1,993)	5,651
Other non-current assets	258	249	—	3,772	113	—	4,392
Total assets	$51,986	$55,020	$2,850	$65,763	$ 17,107	$ (109,677)	$ 83,049
LIABILITIES AND STOCKHOLDERS’ EQUITY							
Liabilities							
Current portion of debt	$1,486	$699	$—	$381	$ 151	$ —	$ 2,717
Other current liabilities - affiliates	1,153	11,949	115	1,482	866	(15,565)	—
All other current liabilities	236	498	12	2,153	1,024	(278)	3,645
Long-term debt	11,833	20,564	386	6,599	715	—	40,097
Notes payable to affiliates	2,619	153	753	18,500	1,240	(23,265)	—
Deferred income taxes	—	—	2	487	1,504	(1,993)	—
All other long-term liabilities and deferred credits	583	78	2	987	514	—	2,164
Total liabilities	17,910	33,941	1,270	30,589	6,014	(41,101)	48,623
Stockholders’ equity							
Total KMI equity	34,076	21,079	1,580	35,174	11,093	(68,926)	34,076
Noncontrolling interests	—	—	—	—	—	350	350
Total stockholders’ equity	34,076	21,079	1,580	35,174	11,093	(68,576)	34,426
Total liabilities and stockholders’ equity	$51,986	$55,020	$2,850	$65,763	$ 17,107	$ (109,677)	$ 83,049

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2015
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	$ (4,218)	$ 6,824	$ 98	$ 10,691	$ 811	$ (8,903)	$ 5,303
Cash flows from investing activities							
Funding to affiliates	(3,204)	(8,388)	(1)	(8,004)	(1,066)	20,663	—
Capital expenditures	(10)	—	(2)	(3,557)	(332)	5	(3,896)
Contributions to investments	(21)	—	—	(70)	(10)	5	(96)
Investment in KMP	(159)	—	—	—	—	159	—
Acquisitions of assets and investments, net of cash acquired	(1,843)	—	—	(236)	—	—	(2,079)
Distributions from equity investments in excess of cumulative earnings	2,653	—	—	143	—	(2,568)	228
Other, net	—	24	5	55	58	(5)	137
Net cash (used in) provided by investing activities	(2,584)	(8,364)	2	(11,669)	(1,350)	18,259	(5,706)
Cash flows from financing activities							
Issuances of debt	14,316	—	—	—	—	—	14,316
Payments of debt	(14,048)	(675)	—	(383)	(10)	—	(15,116)
Funding from (to) affiliates	5,502	6,989	(100)	7,486	786	(20,663)	—
Debt issue costs	(24)	—	—	—	—	—	(24)
Issuances of common shares	3,870	—	—	—	—	—	3,870
Issuance of mandatory convertible preferred stock	1,541	—	—	—	—	—	1,541
Cash dividends	(4,224)	—	—	—	—	—	(4,224)
Repurchases of shares and warrants	(12)	—	—	—	—	—	(12)
Contributions from parents	—	156	—	3	16	(175)	—
Contributions from noncontrolling interests	—	—	—	—	—	11	11
Distributions to parents	—	(4,944)	—	(6,133)	(380)	11,457	—
Distributions to noncontrolling interests	—	—	—	—	—	(34)	(34)
Other, net	—	(1)	—	—	—	—	(1)
Net cash provided by (used in) financing activities	6,921	1,525	(100)	973	412	(9,404)	327
	—	—	—	—	(10)	—	(10)

Effect of exchange rate changes on cash and cash equivalents							
Net increase (decrease) in cash and cash equivalents	119	(15)	—	(5)	(137)	(48)	(86)
Cash and cash equivalents, beginning of period	4	15	—	17	279	—	315
Cash and cash equivalents, end of period	$ 123	$ —	$ —	$ 12	$ 142	$ (48)	$ 229

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2014
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by (used in) operating activities	$ 1,419	$ 3,810	$ (77)	$ 5,876	$ 1,174	$ (7,735)	$ 4,467
Cash flows from investing activities							
Funding to affiliates	(1,949)	(6,644)	—	(3,886)	(1,088)	13,567	—
Capital expenditures	(1)	—	(63)	(3,050)	(705)	202	(3,617)
Contributions to investments	—	(189)	—	(389)	—	189	(389)
Investment in KMP	(550)	—	—	—	—	550	—
Acquisitions of assets and investments	—	—	—	(1,370)	(18)	—	(1,388)
Drop down assets to KMP	875	(875)	—	—	—	—	—
Distributions from equity investments in excess of cumulative earnings	93	440	—	183	—	(534)	182
Other, net	—	27	202	20	(46)	(201)	2
Net cash (used in) provided by investing activities	(1,532)	(7,241)	139	(8,492)	(1,857)	13,773	(5,210)
Cash flows from financing activities							
Issuances of debt	10,594	13,979	—	—	—	—	24,573
Payments of debt	(5,479)	(12,171)	—	(142)	(9)	—	(17,801)
Funding from (to) affiliates	956	4,129	(63)	7,624	921	(13,567)	—
Debt issue costs	(74)	(15)	—	—	—	—	(89)
Cash dividends	(1,760)	—	—	—	—	—	(1,760)
Repurchases of shares and warrants	(192)	—	—	—	—	—	(192)
Cash consideration of Merger Transactions	(3,937)	—	—	—	—	—	(3,937)
Merger Transactions costs	(74)	—	—	—	—	—	(74)
Contributions from parents	—	1,912	—	533	64	(2,509)	—
Contributions from noncontrolling interests	—	—	—	—	—	1,767	1,767
Distributions to parents	—	(4,475)	—	(5,398)	(411)	10,284	—
Distributions to noncontrolling interests	—	—	—	—	—	(2,013)	(2,013)
Other, net	—	(1)	—	(2)	—	—	(3)
Net cash provided by (used in) financing activities	34	3,358	(63)	2,615	565	(6,038)	471
	—	—	—	1	(12)	—	(11)

Effect of exchange rate changes on cash and cash equivalents							
Net decrease in cash and cash equivalents	(79)	(73)	(1)	—	(130)	—	(283)
Cash and cash equivalents, beginning of period	83	88	1	17	409	—	598
Cash and cash equivalents, end of period	$ 4	$ 15	$ —	$ 17	$ 279	$ —	$ 315

153

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2013
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Issuer and Guarantor - Copano	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash provided by (used in) operating activities	$ 1,792	$ 3,669	$ (408)	$ 5,118	$ 769	$ (6,818)	$ 4,122
Cash flows from investing activities							
Funding to affiliates	(413)	(7,183)	(1)	(3,944)	(1,332)	12,873	—
Capital expenditures	(6)	—	(141)	(2,418)	(804)	—	(3,369)
Proceeds from sales of assets and investments	—	—	—	118	372	—	490
Contributions to investments	(6)	(52)	—	(217)	—	58	(217)
Investment in KMP	(68)	—	—	—	—	68	—
Acquisitions of assets and investments	—	—	5	(297)	—	—	(292)
Drop down assets to KMP	994	—	—	(994)	—	—	—
Distributions from equity investments in excess of cumulative earnings	41	296	—	183	—	(335)	185
Other, net	—	(12)	—	105	(12)	—	81
Net cash provided by (used in) investing activities	542	(6,951)	(137)	(7,464)	(1,776)	12,664	(3,122)
Cash flows from financing activities							
Issuances of debt	3,028	10,300	—	14	239	—	13,581
Payments of debt	(3,624)	(7,802)	(854)	(106)	(7)	—	(12,393)
Funding from affiliates	570	2,984	1,400	7,127	792	(12,873)	—
Debt issue costs	(15)	(22)	—	—	(1)	—	(38)
Cash dividends	(1,622)	—	—	—	—	—	(1,622)
Repurchases of shares and warrants	(637)	—	—	—	—	—	(637)
Contributions from parents	—	1,620	—	75	132	(1,827)	—
Contributions from noncontrolling interests	—	—	—	—	—	1,706	1,706
Distributions to parents	—	(3,914)	—	(4,776)	(150)	8,840	—
Distributions to noncontrolling interests	—	—	—	—	—	(1,692)	(1,692)
Other, net	1	(1)	—	—	—	—	—
Net cash (used in) provided by financing activities	(2,299)	3,165	546	2,334	1,005	(5,846)	(1,095)
Effect of exchange rate changes on cash and cash equivalents	—	—	—	1	(22)	—	(21)

Net increase (decrease) in cash and cash equivalents	35	(117)	1	(11)	(24)	—	(116)
Cash and cash equivalents, beginning of period	48	205	—	28	433	—	714
Cash and cash equivalents, end of period	$ 83	$ 88	$ 1	$ 17	$ 409	$ —	$ 598

154

Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2015				
Revenues	$3,597	$3,463	$3,707	$3,636
Operating Income (Loss)	1,078	892	721	(244)
Net Income (Loss)	419	342	183	(736)
Net Income (Loss) Attributable to Kinder Morgan, Inc.	429	333	186	(695)
Net Income (Loss) Available to Common Stockholders	429	333	186	(721)
Basic and Diluted Earnings (Loss) Per Common Share	0.20	0.15	0.08	(0.32)
2014				
Revenues	$4,047	$3,937	$4,291	$3,951
Operating Income	1,147	1,013	1,332	956
Net Income	601	497	779	566
Net Income Attributable to Kinder Morgan, Inc.	287	284	329	126
Basic and Diluted Earnings Per Common Share	0.28	0.27	0.32	0.08

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Operating statistics from our oil and gas producing activities for each of the years ended December 31, 2015, 2014 and 2013 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2015	2014	2013
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$17.68	$20.55	$18.81
Crude oil production(MBbl/d)	41.7	40.8	37.6
SACROC crude oil production(MBbl/d)	28.1	27.6	25.5
Yates crude oil production(MBbl/d)	8.5	8.8	9.0
NGL production(MBbl/d)(d)	4.1	4.2	4.1
NGL production from gas plants(MBbl/d)(e)	6.2	5.9	5.8
Total NGL production(MBbl/d)	10.3	10.1	9.9
SACROC NGL production(MBbl/d)(d)	3.9	3.9	3.8
Yates NGL production(MBbl/d)(d)	0.2	0.2	0.2
Natural gas production(MMcf/d)(d)(f)	0.5	1.0	1.1
Natural gas production from gas plants(MMcf/d)(e)(f)	2.2	1.2	1.7
Total natural gas production(MMcf/d)(f)	2.7	2.2	2.8
Yates natural gas production(MMcf/d)(d)(f)	0.3	1.0	1.1
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$73.11	$88.41	$92.70
NGL price per Bbl(d)(g)	$18.85	$42.61	$46.11
Natural gas price per Mcf(d)(h)	$2.19	$4.04	$3.23
Total NGL price per Bbl(e)	$18.35	$41.87	$46.43
Total natural gas price per Mcf(e)	$2.30	$3.91	$3.21
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$47.56	$86.48	$94.94
NGL price per Bbl(g)	$18.85	$42.61	$46.11
Natural gas price per Mcf(h)	$2.19	$4.04	$3.23

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Computed using production costs, excluding transportation costs, as defined by the SEC. Natural gas volumes were converted to barrels of oil equivalent using a conversion factor of six Mcf of natural gas to one barrel of oil.

(c) Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, and general and administrative expenses directly related to oil and gas producing activities.

(d) Includes only production attributable to leasehold ownership.

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

(f) Excludes natural gas production used as fuel.

(g) Hedge gains/losses for crude oil and NGL are included with crude oil.

(h) Natural gas sales were not hedged.

The following three tables provide supplemental information on oil and gas producing activities, including (i) capitalized costs related to oil and gas producing activities; (ii) costs incurred for the acquisition of oil and gas producing properties and for exploration and development activities; and (iii) the results of operations from oil and gas producing activities.

Our capitalized costs consisted of the following (in millions):

Capitalized Costs Related to Oil and Gas Producing Activities

	As of December 31,		
	2015	2014	2013
Consolidated Companies(a)			
Wells and equipment, facilities and other	$5,332	$4,937	$4,432
Leasehold	658	658	660
Total proved oil and gas properties	5,990	5,595	5,092
Unproved property(b)	142	103	38
Accumulated depreciation and depletion(c)	(5,052)	(4,226)	(3,520)
Net capitalized costs	$1,080	$1,472	$1,610

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries. Includes capitalized asset retirement costs and associated accumulated depreciation.

(b) As of December 31, 2015, capitalized costs related to the unproved property for the Tall Cotton Residual Oil Zone (ROZ) unproved exploration property was $135 million and other miscellaneous unproved property was $7 million.

(c) 2015 amount includes impairment charges of $378 million for Goldsmith Landreth San Andres Unit, $10 million for Katz Strawn Unit and $11 million on other miscellaneous property. 2014 amount includes an impairment charge of $234 million on the Katz Strawn Unit and $1 million on other miscellaneous property.

For each of the years ended December 31, 2015, 2014 and 2013, our costs incurred for property acquisition, development and exploration were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
	2015	2014	2013
Consolidated Companies			
Acquisitions(a)	$—	$—	$285
Development(b)	399	481	471
Exploration(c)	35	95	11

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(a) Acquisition of Goldsmith Landreth San Andres Unit effective June 1, 2013.

(b) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(c) 2015 amounts relate to exploration wells drilled in the Tall Cotton Residual Oil Zone (ROZ) for $35 million. 2014 amounts relate to exploration wells drilled in the Residual Oil Zone (ROZ) for $87 million and the Yates Wolfcamp for $8 million.

Our results of operations from oil and gas producing activities for each of the years ended December 31, 2015, 2014 and 2013 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2015	2014	2013
Consolidated Companies(a)			
Revenues(b)	$1,155	$1,412	$1,376
Expenses:			
Production costs	337	403	344
Other operating expenses(c)	60	99	95
Exploration expense(d)	—	8	—
Impairment(e)	399	235	—
DD&A expenses	388	430	415
Total expenses	1,184	1,175	854
Results of operations for oil and gas producing activities	$(29)	$237	$522

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Revenues include gains attributable to our hedging contracts of $389 million for the year ended December 31, 2015, $28 million for the year ended December 31, 2014 and losses of $31 million for the year ended December 31, 2013.

(c) Consists primarily of CO_2 expense.

(d) Exploration charge for Yates Wolfcamp.

(e) 2015 amount includes impairment charges of $378 million on the Goldsmith Landreth San Andres Unit, $10 million for Katz Strawn Unit and $11 million on other miscellaneous property. 2014 amount includes impairment charge of $234 million on the Katz Strawn Unit and $1 million on other miscellaneous property.

Supplemental information is also provided for the following three items (i) estimated quantities of proved oil and gas reserves; (ii) the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and (iii) a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

The technical persons responsible for preparing the reserves estimates presented in this Supplemental Information meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. They are independent petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our oil and gas properties; and we do not employ them on a contingent basis.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Derek Newton and Mr. Mike Norton. Mr. Newton, a Licensed Professional Engineer in the State of Texas (No. 97689), has been practicing consulting petroleum engineering at NSAI since 1997 and has over 14 years of prior industry experience. He graduated from University College, Cardiff, Wales, in 1983 with a Bachelor of Science Degree in Mechanical Engineering and from Strathclyde University, Scotland, in 1986 with a Master of Science Degree in Petroleum Engineering. Mr. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in

Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our employee who is primarily responsible for overseeing NSAI’s preparation of the reserves estimates is a registered Professional Engineer in the states of Texas and Kansas with a Doctorate of Engineering from the University of Kansas. He is a member of the Society of Petroleum Engineers and has over 30 years of professional engineering experience. We believe the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information become available and contractual and economic conditions change.

Furthermore, our management is responsible for establishing and maintaining adequate internal control over financial reporting, which includes the estimation of our oil and gas reserves. We maintain internal controls and guidance to ensure the reliability of our crude oil, NGL and natural gas reserves estimations, as follows:

- no employee's compensation is tied to the amount of recorded reserves;
- we follow comprehensive SEC compliant internal policies to determine and report proved reserves, and our reserve estimates are made by experienced oil and gas reservoir engineers or under their direct supervision;
- we review our reported proved reserves at each year-end, and at each year-end, the CO_2 business segment managers and the Vice President (President, CO_2) review all significant reserves changes and all new proved developed and undeveloped reserves additions; and
- the CO_2 business segment reports independently of our five remaining reportable business segments.

For more information on our controls and procedures, see Item 9A "Controls and Procedures—Management's Report on Internal Control Over Financial Reporting" included in our Annual Report on Form 10-K for the year ended December 31, 2015.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, current prices and costs calculated as of the date the estimate is made. Pricing is applied based upon the twelve month unweighted arithmetic average of the first day of the month price for the year. Future development and production costs are determined based upon actual cost at year-end. Proved developed reserves are the quantities of crude oil, NGL and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

As of December 31, 2013, we had 67.4 MMBbl of crude oil and 6.7 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2013, we had 39.6 MMBbl of crude oil and 8.0 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2013, were 107.0 MMBbl of crude oil and 14.8 MMBbl of NGL.

During 2014, production from the fields totaled 14.8 MMBbl of crude oil and 1.5 MMBbl of NGL. For 2014, we incurred $502 million in capital costs, and this capital investment resulted in the development of 5.7 MMBbl of crude oil and their transfer from the proved undeveloped category to the proved developed category. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 14.5% of crude oil from the proved undeveloped reserves reported as of December 31, 2013 to the proved developed classification of reserves reported as of December 31, 2014. Revisions to previous transfers of NGL's resulted a downward revision of 0.1 MMBbl for NGL's in the proved developed category that have been reclassified to the proved undeveloped category as of December 31, 2014. This reclassification reflects the transfer of 1.8% of proved developed NGL's reported as of December 31, 2013 to the proved undeveloped classification of reserves reported as of December 31, 2014.

Also during 2014, previous estimates of proved developed reserves were revised upward by 2.0 MMBbl of crude oil and downward 0.5 MMBbl of NGL, and proved undeveloped reserves were revised upward by 3.4 MMBbl of crude oil and downward 1.9 MMBbl of NGL. These revisions are mainly attributed to the addition of projects and the use of higher projected oil recoveries resulting from updated performance at SACROC used to calculate reserves. The proved developed reserves for SACROC represent 32.5% of proved developed reserves. The Katz Strawn Unit also received an addition of proved developed nonproducing reserves volumes. The proved developed reserves for Katz Strawn Unit represent 12.3% of proved developed reserves. Contrarily, there was also a decrease of proved developed producing reserves and proved undeveloped reserves in Goldsmith due to higher operating costs and lower well performance. The proved developed reserves for Goldsmith represent 13.4% of proved developed reserves.

These revisions to our previous estimates, as well as the transfer of proved undeveloped reserves to the proved developed category as discussed above, resulted in the percentage of proved undeveloped reserves increasing from 39.0% at year end 2013 to 40.0% at year end 2014. After giving effect to production and revisions to previous estimates during 2014, total proved reserves of crude oil decreased by 9.5 MMBbl and total proved reserves of NGL decreased by 4.0 MMBbl.

As of December 31, 2014, we had 60.3 MMBbl of crude oil and 4.6 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2014, we had 37.3 MMBbl of crude oil and 6.2 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2014, were 97.6 MMBbl of crude oil and 10.8 MMBbl of NGL.

During 2015, production from the fields totaled 15.2 MMBbl of crude oil and 1.56 MMBbl of NGL. For 2015, we incurred $396 million in capital costs, and this capital investment resulted in the development of 17.3 MMBbl of crude oil and 1.1 MMBbl of NGL and their transfer from the proved undeveloped category to the proved developed category. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 46.4% of crude oil and 17.1% of NGL's from the proved undeveloped reserves reported as of December 31, 2014 to the proved developed classification of reserves reported as of December 31, 2015.

Also during 2015, previous estimates of proved developed reserves were revised downward by 15.8 MMBbl of crude oil and downward 1.3 MMBbl of NGL, and proved undeveloped reserves were revised downward by 18.3 MMBbl of crude oil and downward 5.2 MMBbl of NGL. These revisions are mainly attributed to the substantial deterioration in the price of crude oil. As the result of the decrease in the crude oil price and high operating costs, both the Katz Strawn Unit and the Goldsmith Unit do not have economic proved reserves as of December 31, 2015. The proved developed reserves for the Yates field unit represent 55.2% of proved developed reserves. The proved developed reserves for SACROC represent 44.0% of proved developed reserves.

As of December 31, 2015, we had 46.6 MMBbl of crude oil and 2.8 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2015, we had 1.7 MMBbl of crude oil and no NGL's classified as proved undeveloped reserves. Total proved reserves as of December 31, 2015, were 48.4 MMBbl of crude oil and 2.8 MMBbl of NGL. We currently expect that the proved undeveloped reserves we report as of December 31, 2015 will be developed within the next five years.

During 2015, we filed estimates of our oil and gas reserves for the year 2014 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23. The data on Form EIA-23 was presented on a different basis, and included 100% of the oil and gas volumes from our operated properties only, regardless of our net interest. The difference between the oil and gas reserves reported on Form EIA-23 and those reported in this Supplemental Information exceeds 5%.

The following Reserve Quantity Information table discloses estimates, as of December 31, 2015, of proved crude oil, NGL and natural gas reserves, prepared by Netherland, Sewell & Associates, Inc. (independent oil and gas consultants), of KMCO2 and its consolidated subsidiaries' interests in oil and gas properties, all of which are located in the state of Texas. This data has been prepared using current prices and costs, as discussed above, and the estimates of reserves and future revenues in this Supplemental Information conform to the guidelines of the SEC.

Reserve Quantity Information

	Consolidated Companies(a)		
	Crude Oil (MBbl)	NGL (MBbl)	Natural Gas (MMcf)(b)
Proved developed and undeveloped reserves:			
As of December 31, 2012	81,950	5,976	7,539
Revisions of previous estimates(c)	(2,573)	(43)	(5,063)
Purchases of reserves in place(d)	41,389	10,347	—
Production	(13,735)	(1,499)	(406)
As of December 31, 2013	107,031	14,781	2,070
Revisions of previous estimates(e)	5,378	(2,419)	372
Production	(14,852)	(1,542)	(373)
As of December 31, 2014	97,557	10,820	2,069
Revisions of previous estimates(f)	(34,041)	(6,434)	(1,234)
Production	(15,152)	(1,553)	(309)
As of December 31, 2015	48,364	2,833	526
Proved developed reserves:			
As of December 31, 2013	67,436	6,733	2,070
As of December 31, 2014	60,252	4,584	2,069
As of December 31, 2015	46,627	2,833	526
Proved undeveloped reserves:			
As of December 31, 2013	39,595	8,048	—
As of December 31, 2014	37,305	6,236	—
As of December 31, 2015	1,737	—	—

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

(c) Predominantly due to higher operating costs at the Katz Strawn Unit.

(d) Represents volumes added with acquisition of the Goldsmith Landreth San Andres Unit in June 2013.

(e) Predominately due to the addition of projects and redefined original oil in place values at SACROC, the addition of proved developed nonproducing reserves volumes in the Katz Strawn Unit offset by decreased expected oil recoveries in the Goldsmith Landreth San Andres Unit based on higher operating costs and lower well performance.

(f) Predominately due to lower crude oil prices which resulted in the Goldsmith Landreth San Andres Unit and the Katz Strawn Unit proved reserves being uneconomical under SEC pricing guidelines.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year-to-year are prepared in accordance with the "Extractive Activities—Oil and Gas" Topic of the Codification. The assumptions that underly the computation of the standardized measure of discounted cash flows, presented in the table below, may be summarized as follows:

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the standardized measure includes our estimate of proved crude oil, NGL and natural gas reserves and projected future production volumes based upon year-end economic conditions;

- pricing is applied based upon the 12 month unweighted arithmetic average of the first day of the month price for the year;
- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

The standardized measure of discounted future net cash flows from proved reserves were as follows (in millions):

Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves

	As of December 31,		
	2015	2014	2013
Consolidated Companies(a)			
Future cash inflows from production	$2,500	$9,406	$10,945
Future production costs	(1,276)	(4,294)	(4,214)
Future development costs(b)	(466)	(2,113)	(1,948)
Undiscounted future net cash flows	758	2,999	4,783
10% annual discount	(178)	(1,089)	(2,096)
Standardized measure of discounted future net cash flows	$580	$1,910	$2,687

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Includes abandonment costs.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves

	As of December 31,		
	2015	2014	2013
Consolidated Companies(a)			
Present value as of January 1	$1,910	$2,687	$2,705
Changes during the year:			
Revenues less production and other costs(b)	(375)	(880)	(965)
Net changes in prices, production and other costs	(1,871)	(504)	258
Development costs incurred	396	502	452
Net changes in future development costs	844	(479)	(629)
Revisions of previous quantity estimates(c)	(502)	329	(114)
Purchase of reserves in place(d)	—	—	683
Accretion of discount	178	255	297
Net change for the year	(1,330)	(777)	(18)
Present value as of December 31	$580	$1,910	$2,687

(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.
(b) Excludes gains attributable to our hedging contracts of $389 million for the year ended December 31, 2015, $28 million for the year ended December 31, 2014 and losses of $31 million for the year ended December 31, 2013.
(c) 2015 revisions were primarily due to lower crude oil prices which resulted in the Goldsmith Landreth San Andres Unit and the Katz Strawn Unit proved reserves being uneconomical under SEC pricing guidelines. 2014 revisions were primarily due to, increases due to the addition of projects and redefined original oil in place values at SACROC, additional proved developed nonproducing reserves volumes in the Katz Strawn Unit offset by

decreased oil recoveries and higher operating costs for the Goldsmith Landreth San Andres Unit. 2013 revisions were primarily due to increased operating costs at the Katz Strawn Unit.

(d) Acquisition of the Goldsmith Landreth San Andres Unit in June 2013.

SIGNATURES

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

KINDER MORGAN, INC.
Registrant

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

Date: February 16, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 16, 2016
/s/ STEVEN J. KEAN Steven J. Kean	President and Chief Executive Officer (principal executive officer)	February 16, 2016
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 16, 2016
/s/ TED A. GARDNER Ted A. Gardner	Director	February 16, 2016
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 16, 2016
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 16, 2016
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 16, 2016
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 16, 2016
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 16, 2016
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 16, 2016
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 16, 2016
/s/ C. PARK SHAPER C. Park Shaper	Director	February 16, 2016
/s/ WILLIAM A. SMITH William A. Smith	Director	February 16, 2016
/s/ JOEL V. STAFF Joel V. Staff	Director	February 16, 2016
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 16, 2016

/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 16, 2016