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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, 2013

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

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 ☑ No ☐

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 ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☑ No ☐

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. ☑

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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 ☐ No ☑

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 28, 2013 was approximately $25,669,830,461. As of January 31, 2014, the registrant had 1,030,677,290 Class P shares outstanding.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

BOSTCO	=	Battleground Oil Specialty Terminal Company LLC	KMEP	=	Kinder Morgan Energy Partners, L.P.
Calnev	=	Calnev Pipe Line LLC	KMGP	=	Kinder Morgan G.P., Inc.
Copano	=	Copano Energy, L.L.C.	KMI	=	Kinder Morgan Inc. and its majority-owned and/or controlled subsidiaries, excluding KMP and EPB
El Paso	=	El Paso Holdco LLC	KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
Elba Express	=	Elba Express Company, L.L.C.	KMR	=	Kinder Morgan Management, LLC
ELC	=	Elba Liquefaction Company, L.L.C.	NGPL	=	Natural Gas Pipeline Company of America LLC
EP	=	El Paso Corporation and its its majority-owned and controlled subsidiaries	SFPP	=	SFPP, L.P.
EPB	=	El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	SLC	=	Southern Liquefaction Company, L.L.C.
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.
KinderHawk	=	KinderHawk Field Services LLC	TGP	=	Tennessee Gas Pipeline Company, L.L.C.
$KMCO_2$	=	Kinder Morgan CO_2 Company, L.P.	WYCO	=	WYCO Development L.L.C.

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

Common Industry and Other Terms

AFUCDC	=	allowance for funds used during construction	LLC	=	limited liability company
BBtu/d	=	billion British Thermal Units per day	LNG	=	liquefied natural gas
Bcf/d	=	billion cubic feet per day	MBbl/d	=	thousands of barrels per day
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act	MDth/d	=	thousand of dekatherm per day
CO_2	=	carbon dioxide	MLP	=	master limited partnership
CPUC	=	California Public Utilities Commission	MMBbl/d	=	millions barrels per day
DCF	=	distributable cash flow	MMcf/d	=	million cubic feet per day
DD&A	=	depreciation, depletion and amortization	NEB	=	National Energy Board
Dth	=	dekatherm	NGL	=	natural gas liquids
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	NYMEX	=	New York Mercantile Exchange
EPA	=	United States Environmental Protection Agency	NYSE	=	New York Stock Exchange
FASB	=	Financial Accounting Standards Board	OTC	=	over-the-counter
FERC	=	Federal Energy Regulatory Commission	PHMSA	=	Pipeline and Hazardous Materials Safety Administration
FTC	=	Federal Trade Commission	SEC	=	United States Securities and Exchange Commission
GAAP	=	United States Generally Accepted Accounting Principles	TBtu	=	trillion British Thermal Units
LIBOR	=	London Interbank Offered Rate	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 or to service debt or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- the availability of drop-down assets and the terms and timing of sales from us to KMP and EPB;
- the timing and extent of changes in price trends and overall 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 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 adversely affect our business or our ability to compete;
- interruptions of electric power supply to 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;
- the ability to complete expansion projects and construction of our vessels on time and on budget;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts;
- 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, particularly as it relates to partnerships or other pass-through" entities;

- our ability to offer and sell debt securities, and KMP's and EPB's ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts and on acceptable terms to implement that portion of our business plan that contemplates growth through 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;

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

- the political and economic stability 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 KMP's 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 KMP 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 16 "Litigation, Environmental and Other" 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, 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 the 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—Recent Developments—2014 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.*

Kinder Morgan, Inc. is the largest midstream and the third largest energy company in North America with a combined enterprise value (including its two publicly traded MLP subsidiaries) of approximately $110 billion and unless the context requires otherwise, references to "we," "us," or "our," are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. We own an interest in or operate approximately 80,000 miles of pipelines and 180 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO2 and other products, and our terminals store petroleum products, ethanol and chemicals, and handle such products as coal, petroleum coke and steel. Our common stock trades on the NYSE under the symbol "KMI."

We own the general partner interests of Kinder Morgan Energy Partners, L.P. (NYSE: KMP) and El Paso Pipeline Partners, L.P. (NYSE: EPB), along with limited partner interests in KMP and EPB and shares in Kinder Morgan Management, LLC (NYSE: KMR).

(a) General Development of Business

Organizational Structure

On February 10, 2011, we converted from a Delaware LLC named Kinder Morgan Holdco LLC to a Delaware corporation named Kinder Morgan, Inc. and our outstanding units were converted into classes of our capital stock. These transactions are referred to herein as the "Conversion Transaction." On February 16, 2011, we completed the initial public offering of our Class P common stock, which is sometimes referred to herein as our "common stock." All of the common stock that was sold in the offering was sold by our existing investors consisting of funds advised by or affiliated with Goldman Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC, referred to herein as the "Sponsor Investors." No members of management sold shares in the offering, and we did not receive any proceeds from the offering.

Upon the completion of our initial public offering of Class P common stock we were owned by the public, and by individuals and entities that were the owners of Kinder Morgan Holdco LLC, which are referred to collectively in this report as the "Investors." The Investors were Richard D. Kinder, our Chairman and Chief Executive Officer; the Sponsor Investors; Fayez Sarofim, one of our directors, and investment entities affiliated with him, and an investment entity affiliated with Michael C. Morgan, another of our directors, and William V. Morgan, one of our founders, whom we refer to collectively as the "Original Stockholders"; and a number of other members of our management, who are referred to collectively as "Other Management."

The Investors owned all of our outstanding Class A shares, Class B shares and Class C shares, which are sometimes referred to in this report as the "investor retained stock." Our Class A shares represented the total capital contributed by the Investors (and a notional amount of capital allocated to the contribution of the holders of the Class C shares) at the time of the Going Private Transaction. The Class B shares and Class C shares represented incentive compensation that were held by members of our management, including Mr. Kinder only in the case of the Class B shares.

During the year ended December 31, 2012, certain of the Sponsor Investors (the Selling Stockholders) completed underwritten public offerings (the Offerings) of an aggregate of 198,996,921 shares of our Class P common stock (including 8,700,000 shares that were the subject of an underwriters' option to purchase additional shares). Neither we nor our management sold any shares of common stock in the Offerings, and we did not receive any of the proceeds from the offerings of shares by the Selling Stockholders. As a result of these offerings, the Sponsor Investors advised by or affiliated with Goldman Sachs & Co., The Carlyle Group, and Riverstone Holdings LLC no longer own any of our shares, and representatives of these Sponsor Investors are no longer on our board.

On December 26, 2012, the remaining series of the Class A, Class B and Class C shares held by the Investors automatically converted into shares of Class P common stock upon the election of the holders of at least two-thirds of the shares of each such series of Class A common stock and the holders of at least two-thirds of the shares of each such series of Class B common stock. Subsequent to these conversions, all our Class A, Class B and Class C shares were fully converted and as a result, only our Class P common stock was outstanding as of December 31, 2012. Additionally, as Class A, Class B and Class C shares converted, certain holders of the Class P shares were paid out in cash and their Class P shares were immediately canceled. During the years ended December 31, 2012 and 2011, approximately 2 million and less than 1 million, respectively, Class P shares were canceled resulting in payments totaling approximately $71 million and $2 million, respectively, to the holders of those shares.

We conduct most of our business through our MLPs (KMP and EPB). KMP is a Delaware limited partnership formed in August 1992. KMR is a Delaware LLC formed in February 2001. KMP's general partner, KMGP, owns all of KMR's voting securities. Pursuant to a delegation of control agreement, KMGP, has delegated to KMR, to the fullest extent permitted under Delaware law and KMP's partnership agreement, all of its power and authority to manage and control KMP's business and affairs, except that KMR cannot take certain specified actions without the approval of KMP's general partner. EPB is a Delaware limited partnership formed in 2007. EPB's general partner is El Paso Pipeline GP Company, L.L.C., all of whose stock we indirectly own.

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

Additional information concerning the business of, and our investment in and obligations to, KMP, EPB and KMR is contained in Notes 2 "Summary of Significant Accounting Policies" and 10 "Stockholders Equity" to our consolidated financial statements and KMP's, EPB's and KMR's individual Annual Report on Form 10-K for the year ended December 31, 2012.

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. Canadian dollars are designated as C$. 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 since December 31, 2012. We begin with developments pertaining to our reportable business segments. Additional information regarding most of these items may be found elsewhere in this report.

Natural Gas Pipelines

KMP

- On March 1, 2013, KMP acquired from us both the remaining 50% ownership interest KMP did not already own in EPNG and the remaining 50% ownership interest it did not already own in the EP midstream assets for an aggregate consideration of approximately $1.7 billion, consisting of cash paid, common units issued and debt assumed. In this report, we refer to this acquisition of assets from us as the March 2013 drop-down transaction; the combined group of assets acquired from us effective March 1, 2013 as the March 2013 drop-down asset group; and the EP midstream assets or Kinder Morgan Altamont LLC (formerly, El Paso Midstream Investment Company, L.L.C.) as the midstream assets. KMP acquired its initial 50% ownership interest in the midstream assets effective June 1, 2012 from an investment vehicle affiliated with KKR for consideration of $289 million in common units.

  On August 1, 2012, KMP acquired both the full ownership interest in TGP and an initial 50% ownership interest in EPNG from us for an aggregate consideration of approximately $6.2 billion, consisting of cash paid, common units issued and debt assumed. In this report, we refer to the August 1, 2012 acquisition of assets from us as the August 2012 drop-down transaction; the combined group of assets acquired from us effective August 1, 2012 as the August 2012 drop-down asset group; the combined August 2012 drop-down transaction and the March 2013 drop-down transaction (described above) as the drop-down transactions; and the combined August 2012 drop-down asset group and the March 2013 drop-down asset group (described above) as the drop-down asset groups.

- On May 1, 2013, KMP closed its previously announced acquisition of Copano. KMP 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. KMP issued 43,371,210 of its common units valued at approximately $3.7 billion as consideration for the Copano acquisition (based on the $86.08 closing market price of a common unit on the NYSE on the May 1, 2013 issuance date). In association with KMP's Copano acquisition, we, as general partner of KMP, waived $75 million of incremental incentive distributions for 2013, and intend to forgo incentive distributions of $120 million for 2014, $120 million for 2015, $110 million for 2016 and annual amounts thereafter decreasing by $5 million per year from this level.

  KMP's acquisition of Copano added midstream natural gas assets located primarily in Texas, Oklahoma and Wyoming to its existing business portfolio, and enlarged its existing service offerings to natural gas producers, including gathering, processing, treating and fractionation. Additionally, as a result of this acquisition, KMP is currently pursing incremental development projects in the Eagle Ford shale formation in South Texas, and has gained entry into the Barnett shale formation in North Texas and the Mississippi Lime and Woodford shale formations in Oklahoma. For more information about this acquisition, see Note 3 "Acquisitions and Divestitures" to our consolidated financial statements;

- In April 2013, KMP completed construction and began transportation service on a newly expanded segment of its DeWitt/Karnes (DK) natural gas pipeline system. The DK pipeline system runs through DeWitt County and Karnes County, Texas, and in 2012, Copano initiated an approximately $120 million expansion project to extend the 24-inch diameter pipeline approximately 65 miles southwest into McMullen County, Texas. The expansion was based on a fee-based agreement with a single customer whereby KMP provides midstream gathering and handling services in exchange for committed production volumes;

- In April 2013, KMP commissioned the first of two 400 MMcf/d cryogenic unit expansions at its Houston Central processing plant located in Colorado County, Texas. KMP expects to complete the second expansion in mid-2014, and when completed, total processing capacity at the Houston Central plant will be approximately 1.5 Bcf/d. The current estimate of total project construction costs including expansion of the pipeline capacity upstream of the plant is approximately $250 million;

- TGP continues to move forward on its approximately $83 million Rose Lake expansion project in northeastern Pennsylvania. The project will provide long-term firm transportation service for two shippers that have fully subscribed 230 MDth/d of firm capacity. Subject to regulatory approvals, a November 1, 2014, in-service date is anticipated;

- On July 2, 2013, KMP's wholly-owned subsidiary Sierrita Gas Pipeline LLC entered into a Subscription Agreement with KMP, MGI Enterprises U.S. LLC (an affiliate of PEMEX) and MIT Pipeline Investment Americas, Inc. (an affiliate of Mitsui), whereby MGI and MIT acquired equity interests of 35% and 30%, respectively, in Sierrita in exchange for capital contributions. Each member of Sierrita, including KMP, contributed approximately $5 million, determined based on the anticipated cash requirement of Sierrita through the end of September 2013. Following the execution of a First Amended and Restated LLC Agreement, KMP now operates and owns a 35% equity interest in Sierrita Gas Pipeline LLC, and the investment is accounted for under the equity method of accounting.

  The company will invest approximately $72 million in the proposed Sierrita Pipeline Project, which includes construction of a 60-mile pipeline that will extend from the EPNG pipeline system, near Tucson, Arizona, to the Mexican border at Sasabe, Arizona. The 36-inch Sierrita Pipeline will have approximately 200 MMcf/d of capacity and an affiliate of PEMEX previously executed a 25-year agreement for all of the capacity. Subject to regulatory approvals, the pipeline is expected to be in service in September 2014;

- On September 1, 2013, TGP sold certain natural gas facilities located offshore in the Gulf of Mexico and onshore in the state of Louisiana to Kinetica Partners LLC for an aggregate consideration of $32 million in cash. TGP's investment in the net assets sold in this transaction totaled $89 million, and as a result of the sale, TGP recognized both a $93 million increase in regulated assets and a $36 million gain from the sale of assets in 2013;

- Field survey work continues for TGP's fully subscribed approximately $77 million Connecticut expansion project. The project will provide 72 MDth/d of additional long-term natural gas capacity to two local distribution customers. The project includes constructing approximately 13-miles of new pipeline loops along the TGP system in Connecticut, New York and Massachusetts, and acquiring an existing pipeline lateral from another operator. Pending regulatory approvals, the expansion project is expected to be operational on November 1, 2016;

- The proposed Cameron LNG liquefaction facility at Hackberry, Louisiana, in which we do not own an interest, received Department of Energy conditional approval for non-Free Trade Agreement export on February 11, 2014, and TGP continues to advance plans to transport 900 MDth/d of natural gas to the future facility under long-term agreements. Following a binding open season in the summer of 2013, TGP awarded 300 MDth/d of capacity to a subsidiary of MMGS Inc. (Mitsui) for a 20-year agreement to transport natural gas earmarked for the liquefaction facility, which is slated to begin LNG exports in the second half of 2017. Earlier in 2013, TGP announced a binding, 20-year agreement with anchor shipper Mitsubishi Corporation to ship 600 MDth/d of natural gas for the proposed project. Future shipments by TGP are part of its approximately $138 million Southwest Louisiana Supply Project;

- On November 1, 2013, TGP completed and placed into service its previously announced $504 million Northeast Upgrade project. The project expanded TGP's pipeline facilities in Pennsylvania and New Jersey and provides for additional takeaway capacity from the Marcellus shale gas formation. The fully-subscribed project increased system capacity on TGP's 300 Line system by approximately 636 MDth/d through five segment loops and system upgrades at four existing compressor stations and one meter upgrade in New Jersey;

- On November 1, 2013, TGP completed and placed into service its previously announced $54 million Marcellus Pooling project. The fully subscribed project provides approximately 240 MDth/d of additional firm transportation capacity from the Marcellus shale gas formation. The expansion included approximately eight miles of 30-inch diameter pipeline looping, system modifications and upgrades to allow bi-directional flow at four existing compressor stations in Pennsylvania;

- TGP completed a successful binding open season in December for incremental, north-to-south natural gas transportation capacity on the TGP system totaling 500 MDth/d, which was awarded to five different shippers. The awarded capacity will provide firm transportation service for Marcellus and Utica production from receipt points as far north as Mercer, Pennsylvania, for delivery to multiple delivery points on the Gulf Coast. TGP will invest approximately $156 million in this Utica Backhaul project. Capacity bids exceeded the capacity offered, and TGP is exploring further capacity expansions for its customers;

- TGP signed a binding, 15-year firm transportation agreement with Seneca Resources Corporation to ship 158 MDth/d of natural gas to eastern Canadian markets on the Niagara Expansion Project. Subject to regulatory approvals, the approximately $26 million project is expected to begin service November 1, 2015. Seneca will be the foundation shipper for TGP's Niagara Expansion Project, designed to provide transportation from the Marcellus Shale in Pennsylvania to TGP's interconnect with TransCanada Pipeline in Niagara County, New York, to serve growing markets for U.S. gas in eastern Canada; and

- KMP is investing approximately $126 million for additional compression and pipeline system modifications to expand the Kinder Morgan Texas and Mier-Monterrey pipelines. The project is supported by three customers in Mexico that entered into long-term firm transportation contracts for more than 200 MMcf/d of capacity, which will be phased in from 2014 through 2016. A fourth customer has also contracted for 150 MMcf/d of the project's capacity on an interim basis for use prior to the effective date of the contracts with the other customers, accelerating the timing of the expansion for a projected initial in-service date of September 1, 2014.

EPB

- EPB announced in December that Shell US Gas & Power gave notice to EPB's Elba Liquefaction Company joint venture to move forward on Phase II of the jointly owned natural gas liquefaction project at Elba Island LNG terminal near Savannah, Ga. EPB's SLC unit owns 51% of the Elba Liquefaction Company joint venture. The additional capacity will range from 70 MMcf/d (0.5 million tonnes per year) up to 140 MMcf/d (1.0 million tonnes per year), with EPB's share of estimated capital expenditure for Phase II at the maximum volume of 140 MMcf/d of approximately $224 million. At full development, the Elba liquefaction project is expected to have total capacity of approximately 350 MMcf/d of natural gas (2.5 million tonnes per year of LNG) at a cost of approximately $1.5 billion. Subject to regulatory approvals, Phase I is anticipated to be in service in late 2016 or early 2017 and Phase II is expected to be in service in 2017-2018.

- SNG and Elba Express will invest approximately $279 million to expand its systems following successful open seasons held in August 2013 for incremental, long-term natural gas transportation service. The open seasons generated customer interest in incremental capacity of greater than 700,000 Dth/d that will support southeastern U.S. infrastructure growth and the needs of customers in Georgia, South Carolina and northern Florida. EEC customers have expressed interest that could add incremental capacity of approximately 300,000 Dth/d to the project, which, if constructed, would bring the total capacity of the expansions to approximately 1 Bcf/d. EEC expects an in-service date as early as June 2016 pending regulatory approvals.

- SNG placed its Rose Hill Project into service on schedule in November, which involved facility modifications to benefit both SNG and TGP, a subsidiary of KMP. The approximately $25 million SNG portion of the project allows SNG customers to shift about 450,000 Dth/d to different receipt locations including an interconnection between SNG and TGP. The approximately $9 million TGP portion of the project improved the delivery capabilities from TGP to SNG.

- Construction continues on the WYCO High Plains Expansion Project, a joint venture between CIG and Xcel Energy. The project began partial service in November of 2013, and the approximately $22 million project (EPB's share is $11 million) is expected to be completed in the spring of this year. CIG is constructing approximately 8 miles of pipeline and making other modifications to provide additional takeaway capacity from the Denver-Julesburg Basin and link this prolific basin with CIG's High Plains pipeline system. The project is supported by two shippers who signed long-term contracts for an initial 250,000 Dth/d.

CO_2-KMP

- On June 1, 2013, KMP acquired certain oil and gas properties, rights, and related assets in the Permian Basin of West Texas from Legado Resources LLC for approximately $285 million (before working capital adjustments and excluding assumed liabilities). 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. The field currently produces approximately 1,230 Bbl/d of oil, and as part of the transaction, KMP obtained a long-term supply contract (now held by one of its wholly-owned subsidiaries) for up to 150 MMcf/d of CO_2;

- Construction continues on KMP's approximately $214 million Yellow Jacket Central Facility expansion at the McElmo Dome CO_2 source field in southwest Colorado. The first of four planned expansion projects is expected to be operational by November 2014. These expansions will increase CO_2 production from 1.1 Bcf/d to 1.23 Bcf/d;

- In September 2013, KMP completed the parallel (primary) compression portion of its previously announced $255 million investment to expand the CO_2 capacity of its approximately 87%-owned Doe Canyon Deep unit in southwestern Colorado. Doe Canyon is now producing about 200 MMcf/d of CO_2, substantially higher than the initial projection of 170 MMcf/d. Construction was completed and the booster compression was available for service in mid-December 2013. Additional well drilling and completions in the field have allowed continued production without operation of the booster compression. Booster compression operation is expected to begin in late 2015. Final work continues on pipeline insulation, painting, and final cleanup and is expected to be complete in early April of 2014. KMP plans to drill approximately 18 more wells during the next ten years, with four expected to be drilled in 2014; and

- Work continues on the expansion of KMP's Wink Pipeline System, which transports crude oil from the company's West Texas oil fields to Western Refining Company's facility in El Paso, Texas. KMP is in the process of increasing Wink's capacity from 132 MBbl/d to 145 MBbl/d to meet expected higher future throughput requirements at Western's refinery. KMP anticipates that the new facilities will be online in the first quarter of 2014.

Products Pipelines-KMP

- On September 3, 2013, KMP and Valero Energy Corporation completed construction and placed into service the previously announced Parkway Pipeline, a new 141-mile, 16-inch diameter pipeline that transports refined petroleum products from refineries located in Norco, Louisiana, to Plantation Pipe Line Company's (KMP's approximately 51%-owned equity investee) petroleum transportation hub located in Collins, Mississippi. KMP will operate and own a 50% equity interest in the Parkway Pipeline LLC, which has an initial capacity of 110 MBbl/d, with the ability to expand to over 200 MBbl/d. The approximately $260 million pipeline system is supported by a long-term throughput agreement with a credit-worthy shipper;

- Construction continues on the approximately $360 million petroleum condensate processing facility located near KMP's Galena Park terminal on the Houston Ship Channel. Supported by a long-term, fee-based agreement with BP North America for substantially all 100 MBbl/d of throughput capacity at the facility, the project includes building two separate units to split condensate into its various components and the construction of storage tanks for the almost 2 MMBbl of product that will be split at the facility. The first phase of the splitter is scheduled to be commissioned in June 2014 and the second phase is expected to come online in the second quarter of 2015;

- KMP continues to make progress on pipeline modifications for its approximately $310 million Cochin Reversal project to move light condensate from Kankakee County, Illinois, to existing terminal facilities near Fort Saskatchewan, Alberta. Construction also is underway on the 1 MMBbl storage capacity Kankakee tank farm and associated pipeline facilities where Cochin will interconnect with the Explorer Pipeline and the Enterprise TEPPCO Pipeline. The project remains on schedule for a late June 2014 in-service date;

- Tank and pipeline construction continues on KMP's approximately $109 million expansion of its KMCC pipeline to ConocoPhillips' central delivery facility in Karnes County, Texas. The project, supported by a long-term contract with ConocoPhillips, will extend the 178-mile pipeline 31 miles west from the company's DeWitt Station (west of Cuero, Texas) to ConocoPhillips' central delivery facility in Helena, Texas. KMP expects to complete the project in the third quarter of 2014;

- In January 2014, KMP completed and placed into service its approximately $101 million, 27-mile Sweeny Lateral pipeline, which transports Eagle Ford crude and condensate from its KMCC pipeline to Phillips 66's Sweeny Refinery in Brazoria County, Texas. The two 120,000-barrel storage tanks and seven truck offloading racks at KMP's DeWitt County station are also complete and in service, and the new pumps and two 120,000-barrel storage tanks at KMP's Wharton County pump station will be completed February, 2014;

- KMP has entered into an agreement with a large Eagle Ford Shale producer to extend the KMCC pipeline farther into the Eagle Ford Shale in South Texas. KMP will invest approximately $74 million to build an 18-mile lateral pipeline northwest from its DeWitt Station to a new facility in Gonzales County, where it will construct 300 MBbl of storage, a pipeline pump station and truck offloading facilities. The lateral will have a capacity of 300 MBbl/d and will enable KMP to batch Eagle Ford Gathering LLC crude oil and condensate from the new Gonzales Station via KMCC to its delivery points on the Houston Ship Channel and the soon to be in service Sweeny Lateral pipeline serving the Phillips 66 Sweeny Refinery in Brazoria County, Texas. Construction on the pipeline will start later this month and the project is expected to be completed in the first quarter of 2015;

- In December 2013, KMP and NOVA Chemicals Corporation announced a letter of intent to develop a new products pipeline from the Utica Shale. Under the agreement, KMP's Cochin pipeline will construct, own and operate a 210-mile pipeline from multiple fractionation facilities in Harrison County, Ohio, to KMP's Cochin pipeline near Riga, Michigan, where the company will then move product via Cochin east to Windsor, Ontario, Canada. The proposed approximately $300 million KMP Utica To Ontario Pipeline Access (UTOPIA) would transport previously refined or fractionated NGL, including ethane and propane. UTOPIA is expected to have an initial 50 MBbl/d of capacity, which is expandable to more than 75 MBbl/d, and anticipates a mid-year 2017 in-service date, pending NOVA's execution of a definitive agreement during the binding open season (which is expected in 2014) and timely receipt of necessary permitting and regulatory approvals; and

- KMP and Targa Resources Partners signed a letter of intent in December 2013 to form a joint venture to construct new NGL fractionation facilities at Mont Belvieu, Texas, to provide services for producers in the Utica and Marcellus Shale resource plays in Ohio, West Virginia and Pennsylvania. The obligations under the letter of intent are conditioned upon a successful open season and the construction of the Utica Marcellus Texas Pipeline (UMTP). UMTP is a proposed joint venture between MarkWest Utica EMG and KMP (also announced in the third quarter of 2013), of up to 150 MBbl/d expandable to 400 MBbl/d of maximum pipeline capacity over time. The new NGL fractionation facilities would be located adjacent to Targa's existing fractionation facilities at Mont Belvieu and would provide fractionation services for customers of UMTP. To allow shippers time to assess their Gulf Coast fractionation and pipeline needs, the binding open season currently under way for the proposed Y-grade UMTP has been extended until February 28, 2014. UMTP would involve the abandonment and conversion of over 1,000 miles of our existing TGP system, currently in natural gas service, and building approximately 200 miles of new pipeline.

- KMP entered into a long term agreement in January 2014 with BP North America (BP) for pipeline transportation of Eagle Ford condensate to the Houston Ship Channel. The $28 million project includes construction of tankage and truck rack receipt facilities at the KMCC Helena Station in Karnes County, Texas and is scheduled to be operational in the first quarter of 2015. This new origin facility will provide additional supply for the 100 MBbl/d condensate processing facility subscribed to by BP and currently under construction by KMCC in Galena Park, Texas.

- In December 2013, KMP and its Double Eagle joint venture signed a long term agreement with Anadarko for firm transportation service of Eagle Ford condensate to the Houston Ship Channel. Improvements include construction of tanks and a pump station near Gardendale in LaSalle County, Texas and a new ten mile pipeline joining the Double Eagle and KMCC pipeline systems at Helena Station in Karnes County, Texas. KMP's share of the total project cost is approximately $45 million and the facilities are expected to be operational in early 2015.

Terminals-KMP

- In August 2013, KMP completed and commissioned for service its previously announced petroleum coke terminal located at BP's Whiting refinery in Hammond, Indiana. KMP expects that the terminal will handle approximately 2.2 million tons of petroleum coke per year for the next three years, and this volume is supported by a 20-year service contract with BP. KMP invested approximately $62 million for the construction of this facility, which includes nine conveyors, a 30,000-ton storage barn and a fleet of 190 railcars to move approximately 6,000 tons of petroleum coke per day;

- As of the date of this report, construction continues on the previously announced three phase export coal expansion project at KMP's International Marine Terminals facility (IMT), a multi-product, import-export facility located in Myrtle Grove, Louisiana and owned 66 2/3% by KMP. In August 2013, KMP completed the project's $83 million phase one, which added approximately 800,000 tons of ground storage to the facility. The remaining two phases entail adding a new continuous barge unloader, a new coal reclaim conveyor system and an additional five million tons of coal throughput capacity. KMP expects the entire project to be operational in the second quarter of 2014 and currently, its estimated share of the total expansion project at International Marine Terminals (including all phases) is approximately $150 million;

- Construction continues on KMP's investment of $106 million to meet customer demand in the Houston Ship Channel with a new barge dock adjacent to KMP's Pasadena terminal and nine new storage tanks (with total capacity of 1.2 MMBbl at its Galena Park terminal. The new barge dock is expected to help relieve current dock congestion on the Houston Ship Channel and will enable KMP to handle up to 50 barges per month. The tanks are expected to be placed in-service as they are completed beginning in the third quarter of 2014 and ending in the first quarter of 2015. The barge dock is slated for a fourth quarter 2015 completion;

- KMP's 185-acre Battleground Oil Specialty Terminal Company LLC project located on the Houston Ship Channel is continuing to progress toward completion. Thirty-one of the 51 storage tanks built during phase one construction have been placed in service and the remaining tanks will come online during the first half of 2014. A two-berth ship dock and 12 barge berths were also placed in service in October, 2013. Phase two construction also continues and involves building an additional 0.9 MMBbl of storage capacity. BOSTCO expects phase two to begin service in the third quarter of 2014. The approximately $500 million BOSTCO terminal is fully subscribed for a total capacity of 7.1 MMBbl and is able to handle ultra-low sulfur diesel, residual fuels and other black oil terminal services. KMP owns 55% of and operates BOSTCO;

- KMP is preparing a 42-acre site along the Houston Ship Channel for construction of a new ship dock to handle ocean going vessels and 1.5 MMBbl of liquids storage tanks. The approximately $172 million project is supported by a long-term contract with a major ship channel refiner to construct the tanks and connect KMP's Galena Park terminal to the refiner's location. Construction is scheduled to begin in the second quarter of 2014 and the project is expected to be in service in the first quarter of 2016;

- Construction continues at KMP's Edmonton Terminal expansion in Alberta, Canada. By the end of February 2014, nine tanks with a capacity of 3.4 MMBbl will be in service and phase one will be complete. Construction also continues on phase two, which will add an incremental 1.2 MMBbl storage capacity and is expected to be completed in late 2014. The approximately $419 million project is supported by long-term contracts with major producers and refiners;

- In December 2013, KMP announced a joint venture with Imperial Oil to build the Edmonton Rail Terminal, a crude oil loading facility, near its Edmonton storage terminal on land adjacent to Imperial's Strathcona Refinery. Construction is underway on the Edmonton Rail Terminal, which will be capable of loading one to three unit trains per day totaling 100 MBbl/d at startup, with the potential to expand up to 250 MBbl/d. The new rail terminal will be connected via pipeline to the Trans Mountain terminal and will be capable of sourcing crude oil handled by KMP for delivery by rail to North American markets and refineries. The rail will be constructed and operated by KMP and will connect to both Canadian National and Canadian Pacific mainlines. The joint venture is investing approximately $175 million in the project, and KMP will invest an additional approximately $100 million in pipeline connections and new staging tanks. The facility is expected to be in service at the end of 2014; and

- On January 17, 2014, KMP acquired American Petroleum Tankers (APT) and State Class Tankers (SCT) from affiliates of The Blackstone Group and Cerberus Capital Management for an aggregate consideration of approximately $962 million in cash. APT and SCT are engaged 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. KMP expects that the transaction will be immediately accretive to cash available to its unitholders.

Kinder Morgan Canada -KMP

- On March 14, 2013, KMP closed the previously announced sale of both its one-third equity ownership interest in the Express pipeline system and its subordinated debenture investment in Express to Spectra Energy Corp. For the divestiture of its investments, KMP received net cash proceeds of $402 million (after settlements of both final working capital balances and transaction related selling costs), and it recorded both a pre-tax gain amount of $224 million and an associated increase in income tax expense of $84 million; and

- Trans Mountain Pipeline filed a Facilities Application with Canada's NEB in December 2013 requesting authorization to build and operate the necessary facilities for the proposed $5.4 billion pipeline system expansion. With this filing, the proposed project will undergo a comprehensive public regulatory review. For the past 18 months, Kinder Morgan Canada has engaged and will continue to engage extensively with landowners, Aboriginal groups, communities and stakeholders along the proposed expansion route, and marine communities. The next step is for the NEB to establish a hearing schedule that corresponds to the federal government's legislated 15-month review and decision time frame. Thirteen companies in the Canadian producing, refining and oil export business have signed firm contracts representing a total volume commitment of approximately 708 MBbl/d. Kinder Morgan Canada received approval of the commercial terms related to the expansion from the NEB in May of 2013. The proposed expansion will increase capacity on Trans Mountain from approximately 300 MBbl/d to 890 MBbl/d. If approvals are received as planned, the expansion is expected to be operational at the end of 2017.

Other Segment

- On January 18, 2013, we completed the sale of our equity interests in the Bolivia to Brazil Pipeline that we had acquired as part of the EP acquisition for $88 million. See Note 3 "Acquisitions and Divestitures" to our consolidated financial statements.

Financings

- For information about our 2013 debt offerings and retirements, see Note 8 "Debt" to our consolidated financial statements. For information about our 2013 equity offerings, see Note 10 "Stockholders' Equity-Non-Controlling Interests-Contributions" to our consolidated financial statements.

2014 Outlook

KMP

- As previously announced, KMP anticipates that for the year 2014, (i) it will declare total annual cash distributions of $5.58 per unit, a 5% increase over its cash distributions of $5.33 per unit for 2013; (ii) its business segments will generate approximately $6.4 billion in EBDA , including amortization of excess cost of equity investments and its proportionate share of all DD&A of its unconsolidated joint ventures accounted for under the equity-method of accounting; (iii) it will distribute over $2.5 billion to its limited partners; (iv) it will produce excess cash flow of approximately $15 million above its cash distribution target of $5.58 per unit; and (v) it will invest approximately $3.6

billion for its capital expansion program (including small acquisitions and contributions to joint ventures, but excluding acquisitions from us).

KMP expects that a full-year of contributions from its 2013 acquisitions and expansions, along with partial-year contributions from its anticipated 2014 expansion investments, as described above under -Recent Developments, will help drive earnings and cash flow growth in 2014 and beyond. Generally, KMP's 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, KMP's expectations for 2014 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 Item 1A "Risk Factors" below for more information. Furthermore, we plan to provide updates to our 2014 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

KMP's expectations assume an average WTI crude oil price of approximately $96.15 per barrel in 2014. Although cash generated by KMP's assets is predominantly fee based and is generally not sensitive to commodity prices, the CO_2-KMP business segment is exposed to commodity price risk related to the price volatility of crude oil and NGL. KMP hedges the majority of its crude oil production, but it does have exposure to unhedged volumes, the majority of which are NGL volumes. For 2014, KMP expects that every $1 change in the average WTI crude oil price per barrel will impact the CO_2-KMP segment's cash flows by approximately $7 million (or approximately 0.125% of KMP's combined business segments' anticipated EBDA expenses).

EPB

- EPB expects to declare total cash distribution of $2.60 per unit for 2014, an approximate 2% increase over the $2.55 per unit distributions for 2013. EPB's 2014 budget includes the expected purchase (drop-down transaction) from us of a 50% interest in Ruby Pipeline Holding Company, L.L.C., a 50% interest in Gulf LNG Holdings Group, LLC and a 47.5% interest in Young Gas Storage Company, LTD. The positive impact from the expected drop-down transaction at attractive multiples will be largely offset by the impacts of the SNG and WIC rate case settlements and expected lower rates on contract renewals on the WIC system. In 2014, EPB expects its regulated pipeline and storage assets, along with its LNG business, to generate earnings before DD&A of approximately $1.3 billion (adding back EPB's share of joint venture DD&A), an increase of almost $90 million compared to 2013. EPB also has approximately $1.3 billion of expansion projects under contract with customers, which will benefit its unitholders in 2016 and beyond. Generally, EPB's 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 reservation charges under firm transportation and storage contracts.

KMI

- KMI expects to declare dividends of $1.72 per share for 2014, an 8% increase over its 2013 declared dividend of $1.60 per share. Growth in 2014 cash dividends is expected to be driven by continued strong performance at KMP and contributions from EPB. The growth at KMI from KMP and EPB cash distributions will be partially offset by the loss of income from the 2013 and expected 2014 sales (drop-down) of certain assets to EPB, as described above.

  Our expectations for 2014 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine whether we will obtain these expectations are beyond our ability to control or predict, and because of these uncertainties, it is inadvisable to put undue reliance on any forward-looking statement. Please read our Item 1A "Risk Factors" below for more information.

(b) Financial Information about Segments

For financial information on our six reportable business segments, see Note 15 "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
- maximize the benefits of our financial structure to create 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 (primarily through KMP and EPB) 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, if applicable, and approval of the parties’ respective boards of directors. 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 own and manage a diversified portfolio of energy transportation and storage assets. Our operations are conducted through the following reportable business segments:

- Natural Gas Pipelines—for all periods presented in our financial statements this segment consists of approximately 68,000 miles of natural gas transmission pipelines and gathering lines, plus natural gas storage, treating and processing facilities, through which natural gas is gathered, transported, stored, treated, processed and sold and other equity interests.
- CO2—KMP—which produces, markets and transports, through approximately 1,500 miles of pipelines, CO2 to oil fields that use CO2 to increase production of oil; owns interests in and/or operate four primary oil fields in West Texas; and owns and operates a 450-mile crude oil pipeline system in West Texas;
- Products Pipelines—KMP—which consists of approximately 9,000 miles 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 approximately 62 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the U.S.;
- Terminals—KMP—which consists of approximately 122 owned or operated liquids and bulk terminal facilities and approximately 10 rail transloading and materials handling facilities located throughout the U.S. and portions of Canada, which together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products for customers across the U.S. and Canada
- Kinder Morgan Canada—KMP—which transports crude oil and refined petroleum products through approximately 800 miles of pipelines from Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington; plus five associated product terminal facilities; and
- Other—which primarily includes several physical natural gas contracts with power plants associated with EP’s legacy trading activities. These contracts obligate EP to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028. This segment also included an interest in the Bolivia to Brazil Pipeline, which we sold for $88 million on January 18, 2013.

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 non-FERC regulated assets are contained in KMP's Midstream Group.

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) KMP's assets - approximately 40,000 miles of natural gas pipelines; and (ii) EPB's assets - approximately 13,000 miles of natural gas pipelines; and (iii) our equity interests in entities that have approximately 15,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, that are strategically located throughout the North American natural gas pipeline grid. KMP's transportation network provides access to the major natural gas supply areas in the western U.S., Louisiana, Texas, the Midwest and Northeast, as well as major consumer markets. EPB's transportation network provides access to the major gas supply areas and consumer markets in the Rocky Mountain, Midwest and Southeastern regions. EPB's LNG storage and regasification terminal also serves natural gas supply areas in the southeast.

KMP

KMP Midstream Group

Texas Intrastate Natural Gas Pipeline Group

The Texas intrastate natural gas pipeline group, which operates primarily along the Texas Gulf Coast, consists of the following four natural gas pipeline systems: (i) Kinder Morgan Texas Pipeline; (ii) Kinder Morgan Tejas Pipeline; (iii) Mier-Monterrey Mexico Pipeline; and (iv) Kinder Morgan North Texas Pipeline.

The two largest systems in the group are Kinder Morgan Texas Pipeline and the Kinder Morgan Tejas Pipeline. These pipelines essentially operate as a single pipeline system, providing customers and suppliers with improved flexibility and reliability. The combined system includes approximately 5,763 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 6 Bcf/d of natural gas and approximately 118 billion cubic feet of on-system natural gas storage capacity. In addition, the combined system (i) has facilities to both treat approximately 180 MMcf/d of natural gas for CO_2 and hydrogen sulfide removal, and to process approximately 85 MMcf/d of natural gas for liquids extraction; and (ii) holds contractual rights to process natural gas at certain third party facilities. Transport volumes in 2013 averaged 1,743 BBtu/d.

The Mier-Monterrey Pipeline consists of a 95-mile natural gas pipeline that stretches from the international border between the U.S. and Mexico in Starr County, Texas, to Monterrey, Mexico and can transport up to 425 MMcf/d, though this capacity is being expanded to 640 MMcf/d. The pipeline connects to the Pemex natural gas transportation system and serves a 1,000-megawatt power plant complex. KMP has entered into long-term contracts which have subscribed for substantially all of the pipeline's capacity. Transport volumes in 2013 averaged 379 BBtu/d.

The Kinder Morgan North Texas Pipeline consists of an 82-mile pipeline that transports natural gas from an interconnect with the facilities of NGPL (a 20%-owned equity investee of KMI) in Lamar County, Texas to a 1,750-megawatt electricity generating facility located in Forney, Texas, 15 miles east of Dallas, Texas and to a 1,000-megawatt electricity generating facility located near Paris, Texas. It has the capacity to transport 325 MMcf/d of natural gas and is fully subscribed under a long-term contract that expires in 2032. The system is bi-directional, permitting deliveries of additional supply from the Barnett Shale area to NGPL's pipeline as well as power plants in the area. Transport volumes in 2013 averaged 262 BBtu/d.

Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in KMP's Texas intrastate natural gas pipeline group's market area is primarily composed of industrial (including on-site cogeneration facilities), merchant and utility power, and local natural gas distribution consumption. The industrial demand is primarily a year-round load. Merchant and utility power demand peaks in the summer months and is complemented by local natural gas distribution demand that peaks in the winter months.

Collectively, KMP's Texas intrastate natural gas pipeline system primarily serves the Texas Gulf Coast by selling, transporting, processing and treating natural gas from multiple supply sources to serve the Houston/Beaumont/Port Arthur/Austin industrial markets, local natural gas distribution utilities, electric utilities and merchant power generation markets. It serves as a buyer and seller of natural gas, as well as a transporter of natural gas.

The purchases and sales of natural gas are primarily priced with reference to market prices in the consuming region of the system. The difference between the purchase and sale prices is the rough equivalent of a transportation fee and fuel costs. Generally, KMP purchases natural gas directly from producers with reserves connected to its intrastate natural gas system in South Texas, East Texas, West Texas, and along the Texas Gulf Coast. In addition, KMP also purchase gas at interconnects with third-party interstate and intrastate pipelines. While the intrastate group does not produce gas, it does maintain an active well connection program in order to offset natural declines in production along its system and to secure supplies for additional demand in its market area. KMP's intrastate system is interconnected with both LNG import terminals located on the Texas Gulf Coast. The intrastate group also has access to markets within and outside of Texas through interconnections with numerous interstate natural gas pipelines.

Kinder Morgan Treating L.P.

KMP's subsidiary, Kinder Morgan Treating, L.P., owns and operates (or leases to producers for operation) treating plants that remove impurities (such as CO_2 and hydrogen sulfide) and hydrocarbon liquids from natural gas before it is delivered into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. Additionally, its subsidiary KM Treating Production LLC designs, constructs and sells custom and stock natural gas treating plants and condensate stabilizers. KMP's rental fleet of treating assets includes approximately 211 natural gas amine-treating plants, approximately 20 hydrocarbon dew point control plants, and approximately 186 mechanical refrigeration units that are used to remove impurities and hydrocarbon liquids from natural gas streams prior to entering transmission pipelines.

KinderHawk Field Services LLC

KinderHawk gathers and treats natural gas in the Haynesville and Bossier shale gas formations located in northwest Louisiana. Its assets currently consist of approximately 480 miles of natural gas gathering pipeline currently in service and natural gas amine treating plants having a current capacity of approximately 2,600 gallons per minute (GPM). KinderHawk owns life of lease dedications to gather and treat substantially all of BHP Billiton (BHP) operated Haynesville and Bossier shale gas production at agreed upon rates, as well as minimum volume commitments for a five-year term that expires in May 2015. KinderHawk also holds additional third-party gas gathering and treating commitments. The system is designed to have approximately 2.0 Bcf/d of throughput capacity, however, due primarily to reduced drilling activities, the 2013 average gathering volume was 668 BBtu/d of natural gas.

BHP Billiton Petroleum (Eagle Ford Gathering) LLC

Formerly known as EagleHawk Field Services LLC and currently referred to as EagleHawk in this document, provides natural gas and condensate gathering, treating, condensate stabilization and transportation services in the Eagle Ford shale formation in South Texas. KMP owns a 25% equity ownership in EagleHawk, and accounts for its 25% investment under the equity method of accounting. BHP operates EagleHawk and owns the remaining 75% ownership interest. EagleHawk owns two midstream gathering systems in and around BHP's Hawkville and Black Hawk areas of the Eagle Ford shale formation and combined, its assets consist of natural gas gathering pipelines and condensate gathering lines. The system is designed to have approximately 700 MMcf/d of throughput capacity. In addition, EagleHawk has a life of lease dedication of certain of BHP's Eagle Ford shale reserves, and to a limited extent, contracts with other producers in the Eagle Ford shale formation to provide natural gas and condensate gathering, treating, condensate stabilization and transportation services. The 2013 average gathering volume was 131 BBtu/d of natural gas.

Red Cedar Gathering Company

KMP owns a 49% equity interest in Red Cedar, a joint venture organized in August 1994. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar's natural gas gathering system currently consists of approximately 755 miles of gathering pipeline connecting more than 900 producing wells, 133,400 horsepower of compression at 20 field compressor stations and three CO_2 treating plants. The 2013 average gathering volume was 270 BBtu/d of natural gas and the treating capacity is approximately 750 MMcf/d.

Kinder Morgan Altamont LLC and Camino Real Gathering, L.L.C.

Effective March 1, 2013, as part of the March 2013 drop-down transaction, KMP acquired the remaining 50% equity ownership interest in the midstream assets that it did not already own. The midstream assets include KMP's subsidiaries Kinder Morgan Altamont LLC and Camino Real Gathering Company, L.L.C. These entities own and operate the Altamont natural gas gathering, processing and treating assets located in the Uinta Basin in Utah, and the Camino Real natural gas and oil gathering systems located in the Eagle Ford shale formation in South Texas. The Altamont system consists of over 650 miles of pipeline, over 516 well connections with producers, a natural gas processing plant with a design capacity of 80 MMcf/d, and a NGL fractionator with a design capacity of 5.6 MBbl/d. The Camino Real gathering system has the capacity to gather 150 MMcf/d of natural gas and 110 MBbl/d of crude oil. The 2013 average gathering volumes were 67 BBtu/d for Kinder Morgan Altamont and 103 BBtu/d for Camino Real Gathering.

Endeavor Gathering LLC

KMP owns a 40% equity interest in Endeavor Gathering LLC, which provides natural gas gathering service to GMX Resources, Inc., and others in the Cotton Valley Sands and Haynesville/Bossier Shale horizontal well developments located in East Texas. GMX Resources, Inc. operates and owns the remaining 60% ownership interest in Endeavor Gathering LLC. Endeavor's gathering system consists of over 100 miles of gathering lines and 25,000 horsepower of compression. In 2013, average gathering volume was 28 BBtu/d of natural gas. The natural gas gathering system has takeaway capacity of approximately 115 MMcf/d.

Copano operations (including Eagle Ford Gathering LLC)

The Copano operations assets (including equity investments owned by Copano) include natural gas gathering and intrastate transportation pipeline assets, natural gas processing and fractionation facilities and NGL pipelines. Through the Copano operations' natural gas pipelines, KMP gathers natural gas from wellheads or designated points near producing wells. KMP also treats and processes natural gas as needed to remove contaminants and extract mixed NGL, and it delivers the resulting residue gas to its own and third-party pipelines, local distribution companies, power generation facilities and industrial customers. KMP also sells extracted NGL as a mixture or as fractionated purity products, and it delivers them through its pipeline interconnects and truck loading facilities. KMP processes natural gas from both its own gathering systems and from third-party pipelines, and in some cases, it delivers natural gas and mixed NGL to other third parties who provide KMP with transportation, processing or fractionation services. KMP commonly divides its Copano operations into four regions: South Texas, North Texas, Oklahoma and Rocky Mountain. In 2013, gathering volumes averaged 1,694 BBtu/d and transport volumes averaged 26 BBtu/d.

Copano South Texas Region

The Copano South Texas operations deliver a majority of the natural gas gathered on KMP's wholly owned gathering systems to KMP's Houston Central complex located in Colorado County, Texas. At the Houston Central complex, KMP provides treating, processing and NGL fractionation and transportation services, as needed. The plant and related facilities has approximately 1.1 Bcf/d of processing capacity, consisting of 500 MMcf/d lean oil and 600 MMcf/d cryogenic processing facilities. A new 400 MMcf/d cryogenic processing train (or tower) is under construction, and when it is placed into service at the end of the second quarter of 2014, will largely replace capacity currently served by the less-efficient "lean oil" method of extracting valuable NGL. The Houston Central complex also includes a 1,725 GPM amine treating system, a 44 MBbl/d NGL fractionation facility and a truck rack to facilitate the transport of NGL.

The gathering systems have access to the Houston Central, through both KMP's DeWitt/Karnes (DK) pipeline system (which extends from DeWitt County and Karnes County, Texas), and its Laredo-to-Katy (LK) pipeline system (which extends along the Texas Gulf Coast from south Texas to Houston). KMP's Houston Central complex straddles its LK pipeline system, which allows it to move natural gas from its pipeline systems in south Texas and near the Texas Gulf Coast to the Houston Central complex for processing and treating and then on to downstream markets. KMP also delivers gas from its south Texas gathering systems to other third-party pipelines and processing plants. Depending on the contractual arrangements, third-party service providers collect fees, retain a portion of the NGL, or retain a portion of the proceeds from the sale of the NGL and residue gas in exchange for their services.

KMP provides midstream natural gas services to Eagle Ford Shale producers through its wholly-owned subsidiary Eagle Ford Gathering LLC (Eagle Ford). Eagle Ford provides natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford shale gas formation in South Texas. The Eagle Ford has approximately 190 miles of pipelines with capacity to gather and has contracted processing capacity at Houston Central and third party plants to process over 585 MMcf/d.

The South Texas Copano operations include pipelines which gather natural gas from counties to the north of Houston, Texas and take deliveries from several third-party pipelines. KMP then delivers or sells the natural gas gathered or transported on these systems to utilities and industrial customers. KMP also provides gas conditioning and processing services to natural gas producers in the Woodbine and Eaglebine shale gas formations, emerging rich resource plays located in East Texas near its gathering systems.

The South Texas Copano operations also include KMP's (i) 62.5% equity ownership interest in Webb/Duval Gatherers, the sole owner of the Webb/Duval gas gathering system that provides natural gas gathering services in South Texas; and (ii) 50% equity ownership interest in Liberty Pipeline Group, LLC, the sole owner of the Liberty pipeline system which transports mixed NGL from KMP's Houston Central complex to the Texas Gulf Coast. Webb/Duval Gatherers is a general partnership that KMP operates. Each partner has the right to use its pro rata share of pipeline capacity on this system, subject to applicable ratable take and common purchaser statutes. Energy Transfer Partners, L.P. operates and owns the remaining 50% interest in the Liberty pipeline system.

Copano North Texas Region

The Copano North Texas region provides midstream natural gas services in North Texas, including gathering of natural gas, and related services including compression, dehydration, amine treating, processing and marketing.

KMP's Copano North Texas pipelines gather natural gas from the north Barnett shale combo play located in Cook, Denton, Montague and Wise Counties in Texas and deliver the natural gas to both its Saint Jo processing plant located in Montague County, Texas and to third-party processing plants and pipelines. A large majority of the natural gas on the North Texas system comes from a single producer under a long term contract which includes certain acreage dedications and volume commitments. KMP's Saint Jo high recovery cryogenic plant has an inlet capacity of 100 MMcf/d, and contains both a 1,500 GPM amine treating facility and condensate stabilization facilities. KMP's Saint Jo NGL pipeline system transports NGL from the plant to ONEOK Partners' Hydrocarbon's Arbuckle NGL pipeline system.

Copano Oklahoma Region

The Copano Oklahoma region provides midstream natural gas services in central and east Oklahoma, including primarily low-pressure gathering of natural gas and related services such as compression, dehydration, treating, processing and nitrogen rejection. In addition to gathering natural gas to KMP's plants, the Oklahoma segment delivers natural gas to third-party plants. Depending on the contractual arrangements, third parties collect processing fees, retain a portion of the NGL or residue gas, or retain a portion of the proceeds from the sale of the NGL and residue gas in exchange for their services.

The Oklahoma region includes seven natural gas processing plants with a combined capacity of 236 MMcf/d, and over 3,900 miles of gathering pipelines. The region includes the operations of Southern Dome, LLC, which provides gathering and processing services within the Southern Dome prospect in the southern portion of Oklahoma County. KMP consolidates and currently holds a 69.5% ownership interest in Southern Dome.

Copano Rocky Mountain Region

The Copano Rocky Mountain region provides midstream natural gas services in the Powder River Basin of Wyoming, including gathering and treating of natural gas. The region includes KMP's (i) 51% equity ownership interest in Bighorn Gas Gathering, LLC, the sole owner of the Bighorn natural gas gathering system; and (ii) 37.04% equity ownership interest in Fort Union Gas Gathering, LLC, the sole owner of the Fort Union natural gas gathering system. The Rocky Mountain region also includes firm gathering agreements with Fort Union; firm transportation agreements with Wyoming Interstate Gas Company (WIC), a wholly-owned subsidiary of EBP (which capacity has been released to various producers); and services provided to a number of producers in the Powder River Basin, including producers who deliver natural gas into the Bighorn or Fort Union gathering systems.

Bighorn provides low and high pressure natural gas gathering service to coal-bed methane producers in the Powder River Basin. KMP serves as managing member and field operator of Bighorn. Fort Union takes delivery of natural gas from Bighorn, provides gathering services to other producers and provides amine treating services at its Medicine Bow treating facility in order to meet the quality specifications of downstream pipelines. Pipeline interconnects downstream from the Fort Union system include WIC, Tallgrass Interstate Gas Transportation and Colorado Interstate Gas Company (CIG), a wholly-owned subsidiary of EBP.

Fort Union has firm gathering agreements with each of its four owners, including KMP. Each owner has the right to use a fixed quantity of firm gathering capacity on the system (referred to as variable capacity) that must be paid for only to the extent the owner's dedicated production exceeds that owner's demand capacity. KMP serves as the managing member of Fort Union. Western Gas Wyoming, L.L.C., a subsidiary of Anadarko Petroleum Corporation, acts as field operator, and a ONEOK Partners subsidiary acts as administrative manager and provides gas control, contract management and contract invoicing services.

KMP Interstate Natural Gas Pipelines

TGP

KMP's subsidiary, TGP, owns the approximate 11,840-mile Tennessee Gas natural gas pipeline system. The system has a design capacity of approximately 8.5 BCF/d for natural gas, and during 2013 the average transport volume was 7,082 BBtu/d. The multiple-line TGP system begins in the natural gas producing regions of Louisiana, the Gulf of Mexico and South Texas and extends to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.

KMP's TGP system connects with multiple pipelines (including interconnects at the U.S.-Mexico border and the U.S.-Canada border) that provide customers with access to diverse sources of supply and various natural gas markets. The pipeline system is also connected to four major shale formations: (i) the Haynesville shale formation in northern Louisiana and Texas; (ii) the Marcellus shale formation in Pennsylvania; (iii) the Utica shale formation that spans an area from Ohio to Pennsylvania; and (iv) the previously discussed Eagle Ford shale formation located in South Texas. The TGP system also includes approximately 94 Bcf of underground working natural gas storage capacity through partially owned facilities or long-term contracts. Of this total storage capacity, 29.6 Bcf is contracted from Bear Creek located in Bienville Parish, Louisiana. Bear Creek is a joint venture equally owned by KMP and EPB. The facility has 59.2 bcf of working natural gas storage capacity that is committed equally to KMP and EPB.

KMP's TGP pipeline system provides natural gas services to a variety of customers, including natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies. Its existing transportation and storage contracts expire at various times and in varying amounts of throughput capacity, and TGP's ability to extend its existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Although TGP attempts to recontract or remarket its capacity at the maximum rates allowed under its tariff, it frequently enters into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive.

Western Interstate Natural Gas Pipeline Group

KMP's Western interstate natural gas pipeline systems, which operate along the South Central region and the Rocky Mountain region of the Western portion of the U.S., consist of the following two natural gas pipeline systems (i) the combined El Paso Natural Gas and Mojave Pipelines and (ii) the TransColorado Pipeline.

EPNG

Effective March 1, 2013, as part of the March 2013 drop-down transaction, KMP acquired the remaining 50% equity ownership interest in EPNG that it did not already own. EPNG is the sole owner of (i) the 10,141-mile EPNG pipeline system and (ii) Mojave Pipeline Company, LLC, the sole owner of the approximate 562-mile Mojave Pipeline system. Although the Mojave Pipeline system is a wholly owned entity, it shares common pipeline and compression facilities that are 25% owned by Mojave Pipeline Company, LLC and 75% owned by Kern River Gas Transmission Company.

The EPNG system extends from the San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico. It has a design capacity of 5.65 Bcf/d for natural gas (reflecting winter-sustainable west-flow capacity of 4.85 Bcf/d and approximately 800 MMcf/d of east-end delivery capacity).

The Mojave system connects with other pipeline systems including (i) the EPNG system near Cadiz, California; (ii) the EPNG and Transwestern Pipeline Company, LLC systems at Topock, Arizona; and (iii) the Kern River Gas Transmission Company system in California. The Mojave system also extends to customers in the vicinity of Bakersfield, California. The portion of the total design capacity of the Mojave system attributable to Mojave Pipeline Company, LLC, reflecting total east to west flow activity from Topock to Daggett. The east to west capacity from Topock to the Cadiz interconnect with EPNG is 456 MMcf/d.

In addition to its two pipeline systems, EPNG utilizes its Washington Ranch underground natural gas storage facility located in New Mexico to manage its transportation needs and to offer interruptible storage services. This storage facility has up to 44 billion cubic feet of underground working natural gas storage capacity.

The EPNG system provides natural gas services to a variety of customers, including natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines, and natural gas marketing and trading companies. California, Arizona, and Mexico customers account for the majority of transportation on the EPNG system, followed by Texas and New Mexico. The Mojave system is largely contracted to EPNG, which utilizes the capacity to provide service to EPNG's customers. Furthermore, the EPNG system also delivers natural gas to Mexico along the U.S. border serving customers in the Mexican states of Chihuahua, Sonora, and Baja California. In 2013, transport volumes averaged 3,326 BBtu/d on EPNG and 6 BBtu/d on Mojave.

TransColorado Gas Transmission Company LLC

KMP's subsidiary, TransColorado, owns a 312-mile interstate natural gas pipeline that extends from approximately 20 miles southwest of Meeker, Colorado to the Blanco Hub near Bloomfield, New Mexico. It has multiple points of interconnection with various interstate and intrastate pipelines, gathering systems, and local distribution companies. The TransColorado pipeline system is powered by eight compressor stations having an aggregate of approximately 39,000 horsepower. The system is bi-directional to the north and south and has a pipeline capacity of 1.0 Bcf/d of natural gas. In 2013, transport volumes averaged 303 BBtu/d.

The TransColorado pipeline system receives natural gas from a coal seam natural gas treating plant, located in the San Juan Basin of Colorado, and from pipeline, processing plant and gathering system interconnections within the Paradox and Piceance Basins of western Colorado. It provides transportation services to third-party natural gas producers, marketers, gathering companies, local distribution companies and other shippers. Pursuant to transportation agreements and FERC tariff provisions, TransColorado offers its customers firm and interruptible transportation and interruptible park and loan services. TransColorado also has the authority to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure.

Central Interstate Natural Gas Pipeline Group

KMP's Central interstate natural gas pipeline group, which operates primarily in the Mid-Continent region of the U.S., consists of the following three natural gas pipeline systems (i) Kinder Morgan Louisiana Pipeline; (ii) its 50% ownership interest in Midcontinent Express Pipeline LLC (MEP); and (iii) its 50% ownership interest in Fayetteville Express Pipeline LLC (FEP).

Kinder Morgan Louisiana Pipeline

KMP's subsidiary, Kinder Morgan Louisiana Pipeline LLC owns the Kinder Morgan Louisiana natural gas pipeline system. The pipeline system provides approximately 3.2 Bcf/d of take-away natural gas capacity from the Cheniere Sabine Pass LNG terminal located in Cameron Parish, Louisiana, and transports natural gas to various delivery points located in Cameron, Calcasieu, Jefferson Davis, Acadia and Evangeline parishes in Louisiana. The system capacity is fully supported by 20-year take-or-pay customer commitments with Chevron and Total that expire in 2029. The Kinder Morgan Louisiana pipeline system consists of two segments. The first segment is an approximate 132-mile, 42-inch diameter pipeline that extends from the Sabine Pass terminal to a point of interconnection with an existing Columbia Gulf Transmission line in Evangeline Parish, Louisiana (an offshoot consists of approximately 2 miles of 24-inch diameter pipeline extending away from the 42-inch diameter line to the Florida Gas Transmission Company compressor station located in Acadia Parish, Louisiana). The second segment is an approximate one-mile, 36-inch diameter pipeline that extends from the Sabine Pass terminal and connects to NGPL's natural gas pipeline. In 2013, the Kinder Morgan Louisiana pipeline system transported 9 BBtu/d.

Midcontinent Express Pipeline LLC (MEP)

KMP operates and owns a 50% interest in MEP, the sole owner of the approximate 500-mile Midcontinent Express natural gas pipeline system. The remaining 50% ownership interest in MEP is owned by Regency Midcontinent Express LLC, a wholly-owned subsidiary of Regency Energy Partners, L.P. The Midcontinent Express pipeline system originates near Bennington, Oklahoma and extends eastward through Texas, Louisiana, and Mississippi, and terminates at an interconnection with the Transco Pipeline near Butler, Alabama. It interconnects with numerous major pipeline systems and provides an important infrastructure link in the pipeline system moving natural gas supply from newly developed areas in Oklahoma and Texas into the U.S. eastern markets.

The pipeline system is comprised of approximately 30-miles of 30-inch diameter pipe, approximately 275-miles of 42-inch diameter pipe and approximately 200-miles of 36-inch diameter pipe. The Midcontinent Express system also has four compressor stations and one booster station totaling approximately 144,500 horsepower. It has two rate zones: (i) Zone 1 beginning at Bennington and extending to an interconnect with Columbia Gulf Transmission near Delhi, in Madison Parish Louisiana; and (ii) Zone 2 beginning at Delhi and terminating at an interconnection with Transco Pipeline near the town of Butler in Choctaw County, Alabama. Capacity on the Midcontinent Express system is 99% contracted under long-term firm service agreements that expire between August 2014 and 2020. The majority of volume is contracted to producers moving supply from the Barnett shale and Oklahoma supply basins. In 2013, the Midcontinent Express pipeline system transported 1,315 BBtu/d.

Fayetteville Express Pipeline LLC (FEP)

KMP owns 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% ownership interest and also serves as operator and managing member of FEP. The 185-mile Fayetteville Express pipeline system originates in Conway County, Arkansas, continues eastward through White County, Arkansas, and terminates at an interconnect with Trunkline Gas Company's pipeline in Panola County, Mississippi. The system also interconnects with NGPL's pipeline in White County, Arkansas, Texas Gas Transmission's pipeline in Coahoma County, Mississippi, and ANR Pipeline Company's pipeline in Quitman County, Mississippi. Capacity on the Fayetteville Express system is over 90% contracted under long-term firm service agreements. In 2013, the Fayetteville Express pipeline system transported 1,270 BBtu/d. It has a total capacity of 2.0 Bcf/d.

EPB

EPB owns WIC, SLNG, Elba Express, SNG, CIG, SLC and CPG. Its pipeline systems, storage facilities and LNG receiving terminal operate under tariffs approved by the FERC that establish rates, cost recovery mechanisms and other terms and conditions of services to EPB's customers. The fees or rates established under EPB's tariff are a function of the cost of providing services to its customers, including a reasonable return on its invested capital.

SNG

SNG is comprised of pipelines extending from natural gas supply basins in Texas, Louisiana, Mississippi and Alabama to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SNG owns pipeline facilities serving southeastern markets in Alabama, Georgia and South Carolina. SNG owns 100% of the Muldon storage facility and a 50% interest in Bear Creek. The storage facilities have a combined peak withdrawal capacity of 1.2 Bcf/d. The SNG system is also connected to SLNG's Elba Island LNG terminal. In 2013, transport volumes averaged 2,491 BBtu/d.

CIG

CIG is comprised of pipelines that deliver natural gas from production areas in the Rocky Mountains and the Anadarko Basin directly to customers in Colorado, Wyoming and indirectly to the Midwest, Southwest, California and Pacific Northwest. CIG also owns interests in five storage facilities located in Colorado and Kansas and one natural gas processing plant located in Wyoming.

CIG owns a 50% interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). WYCO owns Totem and the 164-mile High Plains, both of which are in northeast Colorado and are operated by CIG under a long-term agreement with WYCO. Totem has a peak withdrawal capacity of 200 MMcf/d and a maximum injection rate of 150 MMcf/d. Totem services and interconnects with High Plains. WYCO also owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to PSCo's Fort St. Vrain's electric generation plant, which CIG does not operate, and a compressor station in Wyoming leased by WIC. In 2013, transport volumes averaged 2,200 BBtu/d.

WIC

WIC is comprised of a mainline system that extends from western Wyoming to northeast Colorado (the Cheyenne Hub) and several lateral pipeline systems that extend from various interconnections along the WIC mainline into western Colorado, northeast Wyoming and eastern Utah. WIC owns interstate natural gas transportation systems providing takeaway capacity from the mature Overthrust, Piceance, Uinta, Powder River and Green River Basins. In 2013, transport volumes averaged 2,348 BBtu/d.

CPG

CPG is a pipeline system that extends from Cheyenne Hub in Weld County, Colorado and extends southerly to a variety of delivery points in the vicinity of the Greensburg Hub in Kiowa County, Kansas. CPG provides pipeline takeaway capacity from the natural gas basins in the Central Rocky Mountain area to the major natural gas markets in the Mid-Continent region. In 2013, transport volumes averaged 278 BBtu/d.

Elba Express

Elba Express owns the Elba Express pipeline which is capable of transporting natural gas supplies in a northerly direction from the Elba Island LNG terminal to markets in the southeastern and eastern U.S. or transporting natural gas in a southernly direction from interconnections with Transcontinental pipeline to markets located on Elba Express or to interconnections between Elba Express and SNG, Carolina Gas Transmission and SLNG. Under a firm transportation service agreement, the entire south to north capacity of Elba Express is contracted to Shell NA LNG LLC (Shell LNG) for 30 years at a fixed rate that was reduced on December 31, 2013 and will remain flat thereafter with respect to current facilities. The Shell LNG firm transportation service agreement is supported by a parent guarantee from Shell Oil Company (Shell) that secures the timely performance of the obligations of the agreement. Under a separate firm transportation service agreement, the entire north to south capacity of Elba Express is contracted to BG LNG Services, LLC (BG LNG) for 25 years at a fixed rate. The BG LNG firm transportation service agreement is supported by a parent guarantee from BG Energy Holdings Limited that secures the timely performance of the obligations of the agreement. In 2013, transport volumes averaged 181 BBtu/d.

SLNG

SLNG owns the Elba Island LNG receiving terminal, located near Savannah, Georgia. The Elba Island LNG terminal is one of nine land-based terminal facilities in the U.S. capable of providing domestic storage and vaporization services to international producers of LNG. The Elba Island LNG terminal has approximately 11.5 Bcf equivalent of LNG storage capacity and approximately 1.8 Bcf/d of peak send-out capacity. The capacity of the Elba Island LNG terminal is fully contracted with BG LNG Services, LLC (BG LNG) under a negotiated rate contract comprised predominately of a recourse based reservation rate with a small variable component and Shell LNG under a long-term step-down fixed reservation rate contract (that was reduced beginning on December 31, 2013 and will remain flat thereafter). The reservation rate payments due under these contracts are payable to EPB regardless of utilization. The firm SLNG service agreements are supported by parent guarantees from BG Energy Holdings Limited (BG) and Shell that secure the timely performance of the obligations of those agreements. The Elba Island LNG terminal is directly connected to three interstate pipelines, indirectly connected to two others, and also connected by commercial arrangements to a major local distribution company; thus, it is readily accessible to the southeast and mid-Atlantic markets.

Other KMI Owned Natural Gas Interests

Southern Gulf LNG Company, L.L.C.

Southern Gulf LNG Company, L.L.C. (Southern Gulf) owns a 50% interest in Gulf LNG Holdings Group, LLC which owns an LNG receiving, storage and regasification terminal near Pascagoula, Mississippi. The facility has a peak send out capacity of 1.5 Bcf per day and storage capacity of 6.6 Bcf. The terminal is fully subscribed under long term contracts and is directly connected by a five mile pipeline to four interstate pipelines and extends to a natural gas processing plant.

Ruby Pipeline Holding Company, L.L.C.

We own a 50% interest in the Ruby Pipeline Holding Company, L.L.C. which is a 680 mile pipeline extending from Wyoming to Oregon that provides natural gas supplies from the major Rocky Mountain basins to consumers in California, Nevada, and the Pacific Northwest. In 2013, transport volumes averaged 849 BBtu/d.

Young Gas Storage Company, LTD

We own a 47.5% interest in Young Gas Storage Company, LTD which is a storage system consisting of 38 natural gas storage facility wells, a 6,000 horsepower compressor station, a gas processing plant, eleven miles of 20-inch pipeline and four miles of storage gathering line.

KMI expects to sell its interests in Southern Gulf, Ruby Pipeline Holding Company L.L.C. and Young Gas Storage Company, LTD to EPB during 2014.

Citrus Corp.

We own a 50% interest in Citrus Corp. which owns Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas is a 5,300 mile open access interstate natural gas pipeline extending from Texas through the Gulf Coast region of the U.S. to south Florida. Florida Gas' pipeline system primarily receives natural gas from producing basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico, and transports it to the Florida market. In 2013, transport volumes averaged 2,327 BBtu/d.

NGPL

We own an indirect 20% interest in and operate NGPL, which is a 9,220-mile pipeline and storage company.

Competition

The market for supply of natural gas is highly competitive, and new pipelines 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. These 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 transportation rates, terms of service and flexibility and reliability of service. From time to time, other pipeline projects are proposed that would compete with our pipelines, and some proposed pipelines may deliver natural gas to markets we serve from new supply sources closer to those markets. 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—KMP

The CO_2—KMP business segment consists of $KMCO_2$ and its consolidated affiliates. The CO_2—KMP 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. $KMCO_2$'s CO_2 pipelines and related assets allow it to market a complete package of CO_2 supply, transportation and technical expertise to its customers. $KMCO_2$ also holds ownership interests in several oil-producing fields and owns a crude oil pipeline, all located in the Permian Basin region of West Texas.

Oil and Gas Producing Activities

Oil Producing Interests

$KMCO_2$ holds ownership interests in oil-producing fields located in the Permian Basin of West Texas, including: (i) an approximate 97% working interest in the SACROC unit; (ii) an approximate 50% working interest in the Yates unit; (iii) an approximate 99% working interest in the Goldsmith Landreth San Andres unit; (iv) an approximate 21% net profits interest in the H.T. Boyd unit; (v) an approximate 99% working interest in the Katz Strawn unit; and (vi) lesser interests in the Sharon Ridge unit, the Reinecke unit and the MidCross unit.

The SACROC unit is one of the largest and oldest oil fields in the U.S. using CO_2 flooding technology. The field is comprised of approximately 56,000 acres located in the Permian Basin in Scurry County, Texas. $KMCO_2$ has expanded the development of the CO_2 project initiated by the previous owners and increased production and ultimate oil recovery over the last several years. In 2013, the average purchased CO_2 injection rate at SACROC was 126 MMcf/d. The average oil production rate for 2013 was approximately 30,700 Bbl/d of oil (22,500 net Bbl/d to $KMCO_2$).

The Yates unit is also one of the largest oil fields ever discovered in the U.S. The field is comprised of approximately 26,000 acres located about 90 miles south of Midland, Texas. $KMCO_2$'s plan over the last several years has been to maintain overall production levels and increase ultimate recovery from Yates by combining horizontal drilling with CO_2 injection to ensure a relatively steady production profile over the next several years. In 2013, the average purchased CO_2 injection rate at the Yates unit was 99 MMcf/d, and during 2013, the Yates unit produced approximately 20.4 MBbl/d of oil (net 9.0 MBbl/d to $KMCO_2$).

Effective June 1, 2013, $KMCO_2$ acquired from Legado Resources LLC their approximate 99% working interest in the Goldsmith Landreth San Andres oil field unit, which 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. During KMP's period of ownership for the remainder of 2013, the average purchased CO_2 injection rate at the Goldsmith unit was 59 MMcf/d, and during KMP's period of ownership for the remainder of 2013, the Goldsmith unit produced approximately 1,300 Bbl/d of oil (1,100 net Bbl/d to $KMCO_2$).

$KMCO_2$ also operates and owns an approximate 99% working interest in the Katz Strawn unit, located in the Permian Basin area of West Texas. During 2013, the Katz Strawn unit produced approximately 2,700 Bbl/d of oil (2,200 net Bbl/d to $KMCO_2$). In 2013, the average purchased CO_2 injection rate at the Katz Strawn unit was 72 MMcf/d.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which KMP owned interests as of December 31, 2013. The oil and gas producing fields in which KMP interests are located is 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 KMP has a working interest, and "net" refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by KMP:

	Productive Wells(a)		Service Wells(b)		Drilling Wells(c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,164	1,356	1,092	846	3	3
Natural Gas	5	2	—	—	—	—
Total Wells	2,169	1,358	1,092	846	3	3

(a) Includes active wells and wells temporarily shut-in. As of December 31, 2013, KMP 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, 2013. A development well is a well drilled in an already discovered oil field.

The following table reflects KMP's net productive and dry wells that were completed in each of the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	**2012**	**2011**
Productive			
Development	51	59	85
Exploratory	4	—	—
Dry			
Development	—	—	—
Exploratory	—	—	—
Total Wells	55	59	85

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. There were no dry wells completed during the periods presented.

The following table reflects the developed and undeveloped oil and gas acreage that KMP held as of December 31, 2013:

	Gross	**Net**
Developed Acres	75,111	71,919
Undeveloped Acres	17,603	15,334
Total	92,714	87,253

Note: As of December 31, 2013, KMP has 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 KMP's oil and gas producing activities.

Gas and Gasoline Plant Interests

KMCO_2 operates and owns an approximate 22% working interest plus an additional 28% net profits interest in the Snyder gasoline plant. It also operates and owns a 51% ownership interest in the Diamond M gas plant and a 100% ownership interest in the North Snyder plant, all of which are located in the Permian Basin of West Texas. The Snyder gasoline plant processes natural gas produced from the SACROC unit and neighboring CO_2 projects, specifically the Sharon Ridge and Cogdell units, all of which are located in the Permian Basin area of West Texas. The Diamond M and the North Snyder plants contract with the Snyder plant to process natural gas. Production of NGL at the Snyder gasoline plant during 2013 averaged approximately 19.5 gross MBbl/d (9.6 net MBbl/d to KMCO_2 excluding the value associated to KMCO_2's 28% net profits interest).

Sales and Transportation Activities

CO_2

KMCO_2 owns approximately 45% of, and operates, the McElmo Dome unit in Colorado, which contains more than 5.9 trillion cubic feet of recoverable CO_2 as of January 1, 2014. It also owns approximately 87% of, and operates, the Doe Canyon Deep unit in Colorado, which contains approximately 832 Bcf of recoverable CO_2 as of January 1, 2014. For both units combined, compression capacity exceeds 1.6 Bcf/d of CO_2 and during 2013, the two units produced approximately 1.2 Bcf/d of CO_2.

KMCO_2 also owns (i) approximately 11% of the Bravo Dome unit in New Mexico; and (ii) 100% of the St. Johns CO_2 source field and related assets located in Apache County, Arizona, and Catron County, New Mexico. The Bravo Dome unit contains approximately 702 Bcf of recoverable CO_2 as of January 1, 2014 and produced approximately 270 million cubic feet of CO_2 per day in 2013. We are continuing to perform pre-development activity and test wells; however, we believe the St.

Johns CO_2 source field consists of all of the CO_2 and helium located in both the St. Johns gas unit, a 158,000 acre unit located in Apache County, Arizona containing approximately 1.3 trillion cubic feet of recoverable CO_2 as of January 1, 2014, and the Cottonwood Canyon CO_2 unit, an approximate 90,000 acre unit located in Catron County, New Mexico containing approximately 360 Bcf of recoverable CO_2 as of January 1, 2014. The principal market for CO_2 is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain strong for the next several years.

CO_2 Pipelines

Through its 50% ownership interest in Cortez Pipeline Company, $KMCO_2$ owns a 50% equity interest in and operates the approximate 500-mile Cortez pipeline. The pipeline carries CO_2 from the McElmo Dome and Doe Canyon source fields near Cortez, Colorado to the Denver City, Texas hub. In 2013, the Cortez pipeline system transported approximately 1.2 Bcf of CO_2 per day. The tariffs charged by the Cortez pipeline are not regulated, but are based on a consent decree.

$KMCO_2$'s Central Basin pipeline consists of approximately 143 miles of mainline pipe and 177 miles of lateral supply lines located in the Permian Basin between Denver City, Texas and McCamey, Texas. The pipeline has a throughput capacity of 700 MMcf/d. At its origination point in Denver City, the Central Basin pipeline interconnects with all three major CO_2 supply pipelines from Colorado and New Mexico, namely the Cortez pipeline (operated by $KMCO_2$) and the Bravo and Sheep Mountain pipelines (operated by Oxy Permian). Central Basin's mainline terminates near McCamey, where it interconnects with the Canyon Reef Carriers pipeline and the Pecos pipeline.

$KMCO_2$'s Centerline CO_2 pipeline consists of approximately 113 miles of pipe located in the Permian Basin between Denver City, Texas and Snyder, Texas. The pipeline has a capacity of 300 MMcf/d.

$KMCO_2$'s Eastern Shelf CO_2 pipeline, which consists of approximately 91 miles of pipe located in the Permian Basin, begins near Snyder, Texas and ends west of Knox City, Texas. The Eastern Shelf pipeline has a capacity of 110 MMcf/d.

$KMCO_2$ also owns a 13% undivided interest in the 218-mile, Bravo pipeline, which delivers CO_2 from the Bravo Dome source field in northeast New Mexico to the Denver City hub and has a capacity of more than 350 MMcf/d. Tariffs on the Bravo pipeline are not regulated. Occidental Petroleum (81%) and XTO Energy (6%) hold the remaining ownership interests in the Bravo pipeline.

In addition, $KMCO_2$ owns approximately 98% of the Canyon Reef Carriers pipeline and approximately 69% of the Pecos pipeline. The Canyon Reef Carriers pipeline extends 139 miles from McCamey, Texas, to the SACROC unit in the Permian Basin. The pipeline has a capacity of approximately 270 MMcf/d and makes deliveries to the SACROC, Sharon Ridge, Cogdell and Reinecke units. The Pecos pipeline is a 25-mile pipeline that runs from McCamey to Iraan, Texas. It has a capacity of approximately 120 MMcf/d and makes deliveries to the Yates unit. The tariffs charged on the Canyon Reef Carriers and Pecos pipelines are not regulated.

The principal market for transportation on $KMCO_2$'s 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 strong for the next several years. The tariffs charged by the CO_2 pipelines are not regulated; however, the tariff charged on the Cortez pipeline is based on a consent decree.

Crude Oil Pipeline

$KMCO_2$ owns the Kinder Morgan Wink Pipeline, a 450-mile Texas intrastate crude oil pipeline system consisting of three mainline sections, two gathering systems and numerous truck delivery stations. The pipeline allows $KMCO_2$ to better manage crude oil deliveries from its oil field interests in West Texas. $KMCO_2$ has entered into a long-term throughput agreement with Western Refining Company, L.P. (Western Refining) to transport crude oil into Western Refining's refinery located in El Paso, Texas. The throughput agreement expires in 2034. The 20-inch diameter pipeline segment that runs from Wink to El Paso, Texas has a total capacity of 130 MBbl/d of crude oil with the use of drag reduction agent (DRA), but we are currently expanding to 145 MBbl/d. In 2013, the Kinder Morgan Wink Pipeline transported approximately 119 MBbl/d of oil. The tariffs charged on the pipeline system are regulated by both the FERC and the Texas Railroad Commission.

Competition

$KMCO_2$'s 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 USA, Inc., which controls waste CO_2 extracted from natural gas production in the Val Verde Basin of West Texas. $KMCO_2$'s ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. $KMCO_2$ also competes 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.

Products Pipelines—KMP

The Products Pipelines-KMP segment consists of KMP's refined petroleum products, crude oil and condensate, and NGL pipelines and associated terminals, Southeast terminals, and its transmix processing facilities.

West Coast Products Pipelines

KMP's West Coast Products Pipelines include SFPP operations (often referred to in this report as KMP's Pacific operations), Calnev pipeline operations, and West Coast Terminals operations. The assets include interstate common carrier pipelines rate-regulated by the FERC and intrastate pipelines in the state of California, rate-regulated by the CPUC, and certain non rate-regulated operations and terminal facilities.

KMP's Pacific operations serve six western states with approximately 2,500 miles of refined petroleum products pipelines and related terminal facilities that provide refined products to major population centers in the U.S., including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. In 2013, the Pacific operations' mainline pipeline system transported approximately 1.1 MMBbl/d of refined products, with the product mix being approximately 60% gasoline, 23% diesel fuel, and 17% jet fuel.

KMP's Calnev pipeline system consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from its facilities at Colton, California to Las Vegas, Nevada. The pipeline serves the Mojave region through deliveries to a terminal at Barstow, California and two nearby major railroad yards. It also serves Nellis Air Force Base, located in Las Vegas, and serves a military supply terminal at Barstow for various desert defense installations which is operated by Calnev. Calnev also serves Edwards Air Force Base in California through a 55 mile pipeline. In 2013, the Calnev pipeline system transported approximately 104 MBbl/d of refined products, with the product mix being approximately 39% gasoline, 30% diesel fuel, and 31% jet fuel.

West Coast Products Pipelines operations include 15 truck-loading terminals (13 on Pacific operations and two on Calnev) with an aggregate usable tankage capacity of approximately 15.5 MMBbl. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

West Coast Terminals are fee-based terminals located in the Seattle, Portland, San Francisco and Los Angeles areas along the west coast of the U.S. with a combined total capacity of approximately 9.2 MMBbl of storage for both petroleum products and chemicals. West Coast Products Pipelines and associated West Coast Terminals together handled 17.6 MMBbl of ethanol in 2013.

Combined, West Coast Products Pipelines operations' pipelines transport approximately 1.2 MMBbl/d of refined petroleum products, providing pipeline service to approximately 28 customer-owned terminals, 10 commercial airports and 15 military bases. The pipeline systems serve approximately 60 shippers in the refined petroleum products market, the largest customers being major petroleum companies, independent refiners, and the U.S. military. The majority of refined products supplied to the West Coast Product Pipelines come from the major refining centers around Los Angeles, San Francisco, West Texas and from waterborne terminals and connecting pipelines located near these refining centers.

Plantation Pipe Line Company

KMP owns approximately 51% of Plantation, the sole owner of the approximately 3,100-mile refined petroleum products Plantation pipeline system serving the southeastern U.S. KMP operates the system pursuant to agreements with Plantation and its wholly-owned subsidiary, Plantation Services LLC. The Plantation pipeline system originates in Louisiana and terminates in the Washington, D.C. area. It connects to approximately 130 shipper delivery terminals throughout eight states and serves as a common carrier of refined petroleum products to various metropolitan areas, including Birmingham, Alabama; Atlanta, Georgia; Charlotte, North Carolina; and the Washington, D.C. area. An affiliate of ExxonMobil Corporation owns the remaining approximately 49% ownership interest, and ExxonMobil has historically been one of the largest shippers on the Plantation system both in terms of volumes and revenues. In 2013, Plantation delivered approximately 576,600 Bbl/d of refined petroleum products, with the product mix being approximately 71% gasoline, 17% diesel fuel, and 12% jet fuel.

Products shipped on Plantation originate at various Gulf Coast refineries from which major integrated oil companies and independent refineries and wholesalers ship refined petroleum products, from other products pipeline systems, and via marine facilities located along the Mississippi River. Plantation ships products for approximately 40 companies to terminals throughout the southeastern U.S. Plantation's principal customers are Gulf Coast refining and marketing companies, and fuel wholesalers.

Central Florida Pipeline

KMP's Central Florida pipeline system consists of a 110-mile, 16-inch diameter pipeline that transports gasoline and ethanol, and an 85-mile, 10-inch diameter pipeline that transports diesel fuel and jet fuel from Tampa to Orlando. The Central Florida pipeline operations also include two separate liquids terminals located in Tampa and Taft, Florida, which KMP owns and operates.

In addition to being connected to the Tampa terminal, the Central Florida pipeline system is connected to terminals owned and operated by TransMontaigne, Citgo, Buckeye, and Marathon Petroleum. The 10-inch diameter pipeline is connected to the Taft terminal (located near Orlando), has an intermediate delivery point at Intercession City, Florida, and is also the sole pipeline supplying jet fuel to the Orlando International Airport in Orlando, Florida. In 2013, the pipeline system transported approximately 95,400 Bbl/d of refined products, with the product mix being approximately 71% gasoline and ethanol, 10% diesel fuel, and 19% jet fuel.

The Tampa terminal contains approximately 1.6 MMBbl of refined products storage capacity and is connected to two ship dock facilities in the Port of Tampa and is also connected to an ethanol unit train off-load facility. The Taft terminal contains approximately 0.8 MMBbl of storage capacity, for gasoline, ethanol and diesel fuel for further movement into trucks.

Cochin Pipeline System

KMP's Cochin pipeline system consists of an approximately 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta and Windsor, Ontario, along with five terminals. The pipeline operates on a batched basis and has an estimated system capacity of 50 MBbl/d. It includes 31 pump stations spaced at 60 mile intervals and five U.S. propane terminals. Underground storage is available at Fort Saskatchewan, Alberta and Windsor, Ontario through third parties. The pipeline traverses three provinces in Canada and seven states in the U.S. and can transport ethane, propane, butane and NGL to the midwestern U.S. and eastern Canadian petrochemical and fuel markets. In 2013, the system transported approximately 33 MBbl/d of propane, and 16.4 MBbl/d of ethane-propane mix. In mid-2014, KMP expects to complete the expansion and reversal of the Cochin pipeline system to transport 95 MBbl/d of condensate from a new receipt terminal in Kankakee County, Illinois to third party storage in Fort Saskatchewan, Alberta.

Cypress Pipeline

KMP owns 50% of Cypress Interstate Pipeline LLC, the sole owner of the Cypress pipeline system. KMP operates the system pursuant to a long-term agreement. The Cypress pipeline is an interstate common carrier NGL pipeline originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a connection with Westlake Chemical Corporation, a major petrochemical producer in the Lake Charles, Louisiana area. Mont Belvieu, located approximately 20 miles east of Houston, is the largest hub for NGL gathering, transportation, fractionation and storage in the U.S. The Cypress pipeline system has a current capacity of approximately 55 MBbl/d for NGL. In 2013, the system transported approximately 52.8 MBbl/d.

Southeast Terminals

KMP's Southeast terminal operations consist of 28 high-quality, liquid petroleum products terminals located along the Plantation/Colonial pipeline corridor in the Southeastern U.S. The marketing activities of the Southeast terminal operations are focused on the Southeastern U.S. from Mississippi through Virginia, including Tennessee. The primary function involves the receipt of petroleum products from common carrier pipelines, short-term storage in terminal tankage, and subsequent loading onto tank trucks. Combined, the Southeast terminals have a total storage capacity of approximately 9.1 MMBbl. In 2013, these terminals transferred approximately 418.1 MBbl/d of refined products and together handled 15.8 MMBbl of ethanol.

Transmix Operations

KMP's Transmix operations include the processing of petroleum pipeline transmix, a blend of dissimilar refined petroleum products that have become co-mingled in the pipeline transportation process. During pipeline transportation, different products are transported through the pipelines abutting each other, and generate a volume of different mixed products called transmix. KMP processes and separates pipeline transmix into pipeline-quality gasoline and light distillate products at six separate processing facilities located in Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; St. Louis, Missouri; and Greensboro, North Carolina. Combined, these transmix facilities handled approximately 11.3 MMBbl in 2013.

Kinder Morgan Crude & Condensate Pipeline

The Kinder Morgan Crude and Condensate Pipeline is a Texas intrastate pipeline that transports crude oil and condensate from the Eagle Ford shale field in South Texas to the Houston ship channel refining complex. The 24-to-30-inch pipeline currently originates in Dewitt County, Texas, and extends approximately 178 miles to third party storage. It delivers product to multiple terminaling facilities that provide access to local refineries, petrochemical plants and docks along the Texas Gulf Coast. The pipeline operates on a batch basis and has a capacity of 300 MBbl/d. In 2013, the pipeline system transported approximately 8.8 MMBbl. Due to strong interest for transportation of Eagle Ford crude and condensate to the Houston Ship Channel, KMP has secured long-term commitments for more than two-thirds of the 300 MBbl/d of capacity on the pipeline.

Double Eagle Pipeline LLC

As part of KMP's May 1, 2013 Copano acquisition, it acquired a 50% ownership interest in Double Eagle Pipeline LLC, the sole owner of the Double Eagle pipeline system. Double Eagle pipeline system provides crude oil and condensate gathering and transportation services for Eagle Ford shale gas producers. The remaining 50% ownership interest in Double Eagle is owned by Magellan Midstream Partners, L.P. KMP operates the approximate 195-mile Double Eagle pipeline system which consists of three segments (i) a 73-mile line that extends from Three Rivers, Texas, in Live Oak County, Texas to Magellan's Corpus Christi terminal; (ii) a 37-mile line that extends from northern Karnes County Texas to Three Rivers; and (iii) an 85-mile line that extends from Gardendale, Texas, in LaSalle County to Three Rivers. The Double Eagle joint venture operations also include a truck unloading facility and a 400 MBbl storage facility located along the pipeline near Three Rivers for deliveries and storage of condensate destined for Corpus Christi. Combined, the pipeline system has a capacity of 100 MBbl/d, but can be expanded to approximately 150 MBbl/d, and is supported by long-term customer commitments from Talisman Energy USA Inc. and Statoil Marketing and Trading (US) Inc.

Competition

KMP's 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. The Products Pipelines' terminal operations compete with proprietary terminals owned and operated by major oil companies and other independent terminal operators, and KMP's transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Terminals—KMP

KMP's Terminals segment includes the operations of its petroleum, chemical and other liquids terminal facilities (other than those included in the Products Pipelines—*KMP* segment) and all of its coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately 122 owned or operated liquids and bulk terminal facilities and approximately 10 rail transloading and materials handling facilities. KMP's terminals are located throughout the U.S. and in portions of Canada. KMP believes the location of its facilities and its ability to provide flexibility to customers helps keep customers at its terminals and provides KMP opportunities for expansion. KMP often classifies its terminal operations based on the handling of either liquids or bulk material products.

Liquids Terminals

KMPs liquids terminals operations primarily store refined petroleum products, petrochemicals, ethanol, industrial chemicals and vegetable oil products in above-ground storage tanks and transfer products to and from pipelines, vessels, tank trucks, tank barges, and tank railcars. Combined, KMP's approximately 40 liquids terminals facilities possess liquids storage capacity of approximately 68.1 MMBbl, and in 2013, these terminals handled approximately 618.9 MMBbl of liquids products, including petroleum products, ethanol and chemicals.

Bulk Terminals

KMPs bulk terminal operations primarily involve dry-bulk material handling services. KMP also provides conveyor manufacturing and installation, engineering and design services, and in-plant services covering material handling, conveying, maintenance and repair, truck-railcar-marine transloading, railcar switching and miscellaneous marine services. KMP owns or operates approximately 82 dry-bulk terminals in the U.S. and Canada, and combined, its dry-bulk and material transloading facilities (described below) handled approximately 89.9 million tons of coal, petroleum coke, fertilizers, steel, ores and other dry-bulk materials in 2013.

Materials Services (rail transloading)

KMP's materials services operations include rail or truck transloading shipments from one medium of transportation to another conducted at approximately 10 owned and non-owned facilities. The Burlington Northern Santa Fe, CSX, Norfolk Southern, Union Pacific, Kansas City Southern and A&W railroads provide rail service for these terminal facilities. Approximately 50% of the products handled are liquids, including an entire spectrum of liquid chemicals, and the rest are dry-bulk products. Many of the facilities are equipped for bi-modal operation (rail-to-truck, and truck-to-rail) or connect via pipeline to storage facilities. Several facilities provide railcar storage services. KMP also designs and builds transloading facilities, performs inventory management services, and provides value-added services such as blending, heating and sparging.

Effective March 31, 2013, TRANSFLO, a wholly owned subsidiary of CSX, elected to terminate their contract with KMP's materials handling wholly-owned subsidiary, Kinder Morgan Materials Services (KMMS). This contract covered 25 terminals located on the CSX Railroad throughout the southeastern section of the U.S. KMMS performed transloading services at the 25 terminals, which included rail-to-truck and truck-to-rail transloading of bulk and liquid products.

Competition

KMP is one of the largest independent operators of liquids terminals in the U.S, based on barrels of liquids terminaling capacity. Its liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical and pipeline companies. Its 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. KMP's rail transloading (material services) operations compete with a variety of single- or multi-site transload, warehouse and terminal operators across the U.S. its ethanol rail transload operations compete with a variety of ethanol handling terminal sites across the U.S., many offering waterborne service, truck loading, and unit train capability serviced by Class 1 rail carriers.

Kinder Morgan Canada—KMP

KMP's Kinder Morgan Canada business segment includes 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 715 miles in length. KMP also owns 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.

The crude oil and refined petroleum products transported through Trans Mountain pipeline system originate in Alberta and British Columbia. The refined and partially refined petroleum products transported to Kamloops, British Columbia and Vancouver originate from oil refineries located in Edmonton, Alberta. Petroleum products delivered through Trans Mountain's pipeline system are used in markets in British Columbia, Washington State and elsewhere offshore. In 2013, the Trans Mountain pipeline system delivered an average of 264 MBbl/d. In February 2013, Trans Mountain completed negotiations with the Canadian Association of Petroleum Producers for a new negotiated toll settlement effective for the period beginning January 1, 2013 and ending December 31, 2015. The NEB approved the toll settlement in April 2013. The 2013-2015 negotiated settlement contains provisions for extension of the settlement that would likely cause the 2013-2015 settlement to be extended to the completion of the expansion of Trans Mountain at the end of 2017. In 2012, Trans Mountain succeeded in contracting approximately 80% of its total planned capacity based on a $5.4 billion expansion of the Trans Mountain pipeline from 300 MBbl to 890 MBbl, based on 15 and 20 year take or pay contracts. In May 2013, the NEB approved the commercial terms of the expansion agreement. On December 16, 2013, Trans Mountain filed its application for a Certificate of Public need, including NEB approval on all remaining aspects of the project. The regulatory process is expected to be completed in the middle of 2015.

Trans Mountain also operates a 5.3 mile spur line from its Sumas Pump Station to the U.S. - Canada international border where it connects with KMP's approximate 63-mile, 16-inch to 20-inch diameter Puget Sound pipeline system. The Puget Sound pipeline system in the state of Washington has a sustainable throughput capacity of approximately 180 MBbl/d when heavy crude oil represents approximately 5% of throughput, and it connects to four refineries located in northwestern Washington State. The volumes of crude oil shipped to the state of Washington fluctuate in response to the price levels of Canadian crude oil in relation to crude oil produced in Alaska and other offshore sources and in response to available capacity on the Trans Mountain system.

Jet Fuel Pipeline System

KMP also owns and operates 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 KMP's previously announced expansion proposal, discussed above in "-(a) General Development of Business-Recent Developments-Kinder Morgan Canada," it believes that the Trans Mountain pipeline facilities provide it 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 2013, our other segment activities include those operations that were acquired from EP on May 25, 2012 and are primarily related to several physical natural gas contracts with power plants associated with EP's legacy trading activities. These contracts obligate EP to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028. This segment also included an interest in the Bolivia to Brazil Pipeline, which we sold for $88 million on January 18, 2013.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2013, 2012 and 2011, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. KMP's Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2-KMP business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2-KMP business segments in 2013, 2012 and 2011 accounted for 28%, 28% and 42%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of its natural gas purchases to its 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 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 KMP's 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 16 "Litigation, Environmental and Other" 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 to meet competition, 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 offer 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 a fixed rate 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, and while rates may vary by shipper and circumstance, the terms and conditions of pipeline transportation and storage services are not generally negotiable.

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, through the mid-1990's, the FERC initiated a number of regulatory changes intended to create a more competitive 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;
- 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; and
- 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).

The FERC standards of conduct address and clarify multiple issues, 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; (iv) independent functioning; (v) transparency; and (vi) the interaction of FERC standards with the North American Energy Standards Board business practice standards. The FERC also promulgates certain standards of conduct that apply uniformly to interstate natural gas pipelines and public utilities. In light of the changing structure of the energy industry, these standards of conduct govern employee relationships-using a functional approach-to ensure that natural gas transmission is provided on a nondiscriminatory basis. Pursuant to the FERC's standards of conduct, a natural gas transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. Additionally, no-conduit provisions prohibit a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit.

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 KMP's 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 KMP 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 KMP's FERC regulated rates also could arise with respect to its intrastate rates. Certain of the Pacific operations' pipeline rates have been, and continue to be, subject to complaints with the CPUC, as is more fully described in Note 16 "Litigation, Environmental and Other" to our consolidated financial statements.

Texas Railroad Commission Rate Regulation

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

Mexico - Energy Regulating Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulating Commission (the Commission) that defines the general and directional conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2032.

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 project presented to 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 the Department of Transportation PHMSA, including those requiring us to develop and maintain integrity management programs to comprehensively evaluate certain 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 the integrity management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the 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 the Department of Transportation 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.

The President signed into law new pipeline safety legislation in January 2012, The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which increased penalties for violations of safety laws and rules, among other matters, and may result in the imposition of more stringent regulations in the next few years. PHMSA is also currently considering changes to its regulations. 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 the 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 demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records or 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 regulation, and actual future 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, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, 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 comparable 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.

KMP is 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, KMP monitors the foreign ownership of its ownership interests. If KMP does not comply with such requirements, it would be prohibited from operating its vessels in U.S. coastwise trade, and under certain circumstances KMP would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for its vessels, fines or forfeiture of the 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 KMP, provided that KMP is considered a U.S. citizen for this purpose). If one of its vessels were purchased or requisitioned by the U.S. government under this law, KMP 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, KMP 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 $378 million as of December 31, 2013. Our reserve estimates range in value from approximately $378 million to approximately $562 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 16 “Litigation, Environmental and Other” 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. We believe that the operations of our pipelines, storage facilities and terminals are in substantial compliance with such statutes. 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.

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 is considering 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 CO2 and methane. Our facilities are subject to substantial compliance with these requirements. Operational and/or regulatory changes could require additional facilities to comply with greenhouse gas emissions reporting and permitting requirements. Additionally, the EPA has announced that it will propose new regulations of greenhouse gases which may impose further requirements, including emission control requirements, on Kinder Morgan facilities.

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 and our subsidiaries 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 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-KMP 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 11,075 full-time people at December 31, 2013, including approximately 828 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2014 and 2018. We consider relations with our employees to be good.

Most of our employees are employed by a limited number of our subsidiaries and provide services to one or more of our business units (subsidiaries or limited partnerships). The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated to our subsidiaries and limited partnerships. 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 and limited partnerships pursuant to existing expense allocation procedures. 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. These processes are in accordance with limited partnership agreements, board of directors' approved policies and other agreements including the Delegation of Control Agreement among KMGP, KMR, KMP and others.

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 15 "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 Our Business

We are dependent on cash distributions received from KMP and EPB.

For 2013, distributions from KMP and EPB represented approximately 87% of the sum of total cash generated by (i) distributions payable to us by our MLPs (on a declared basis) and (ii) distributable cash generated by assets we own and our share of cash generated by our joint venture investments. A decline in KMP's and/or EPB's revenues or increases in its general and administrative expenses, principal and interest payments under existing and future debt instruments, expenditures for taxes, working capital requirements or other cash needs will limit the amount of cash KMP and EPB can distribute to us, which would reduce the amount of cash available for dividends to our stockholders, which could be material.

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

Our assets and operations are subject to regulation and oversight by federal, state 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. Furthermore, new laws or regulations sometimes arise from unexpected sources. For example, the Department of Homeland Security Appropriation Act of 2007 required the issuance of regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." 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 allows us to recover in our rates, or to the extent that there is a lag before we can file and obtain rate increases, such events can have a negative impact upon our operating results can be negatively impacted.

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 initiate investigations to determine whether some interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 16 "Litigation, Environmental and Other" to our consolidated financial statements, to the rates we charge on KMP's, EPB's and our other pipelines. Any successful challenge could materially adversely affect our future earnings, cash flows and financial condition.

Energy 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 natural gas transmission and storage activities and refined petroleum products and CO_2 transportation activities-such as leaks, explosions and mechanical problems-that could result in substantial financial losses. In addition, 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 earnings 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.

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

Primarily, through our regulated pipeline subsidiaries, we are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the U.S. DOT and 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 the compliance costs are pipeline integrity testing and the repairs found to be necessary. Changes such as advances of 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 pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. 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.

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

Following our January 2014 acquisition of American Petroleum Tankers and State Class Tankers, 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 by 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.

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 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 or our 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 level of 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 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.

In addition, our oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. Due to the rise of oil and gas production in new areas of the country and increased public scrutiny of fracturing and other practices in oil and gas drilling, 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.

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-Climate Change."

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

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. The EPA regulates the greenhouse gas emissions and requires the reporting of greenhouse gas emissions in the U.S. for emissions from specified large greenhouse gas emission sources, fractionated NGL, and the production of naturally occurring CO_2, like our McElmo Dome CO_2 field, even when such production is not emitted to the atmosphere.

Because our operations, including our compressor stations and natural gas processing plants in our Natural Gas Pipelines segment, emit various types of greenhouse gases, primarily methane and CO_2, such regulation could increase our costs related to operating and maintaining 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. Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows. For more information about climate change regulation, see Items 1 and 2 "Business and Properties-(c) Narrative Description of Business-Environmental Matters-Climate Change.

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, which could adversely impact KMP's and EPB's revenues by decreasing the volumes of natural gas transported on their natural gas pipelines.

The natural gas industry is increasingly relying on natural gas supplies from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of natural gas 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 natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas transported on our or our joint ventures' natural gas pipelines, several of which gather gas from areas in which the use of hydraulic fracturing is prevalent.

We may 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.

Cost overruns and delays on our expansion and new build projects could adversely affect our business.

KMP, EPB and our other pipelines regularly undertake major construction projects to expand their existing assets and to construct new assets. A variety of factors outside of their control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as performance by third-party contractors, has resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays in completing a project could have a material adverse effect on our return on investment, results of operations and cash flows.

We must either obtain the right from landowners or exercise the power of eminent domain in order to use most of the land on which our pipelines are constructed, and we are subject to the possibility of increased costs to retain necessary land use.

We obtain the right to construct and operate pipelines on other owners' land for a period of time. 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 KMP, EPB or our other pipelines have the power of eminent domain for their pipelines, other than interstate natural gas pipelines, varies from state to state depending upon the type of pipeline-petroleum liquids, natural gas, CO_2 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 subsidiaries' business if they were to lose the right to use or occupy the property on which pipelines are located.

KMP's and EPB's acquisition strategies and expansion programs require access to new capital. Limitations on their access to capital would impair our ability to grow.

Consistent with the terms of KMP's and EPB's partnership agreements, KMP and EPB distribute most of the cash generated by their operations. As a result, they have relied on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund acquisition and growth capital expenditures. However, to the extent our limited partnerships are unable to continue to finance growth externally; their cash distribution policy will significantly impair their ability to grow. KMP and/or EPB may need new capital to finance these activities. Limitations on access to capital, whether due to tightened capital markets, more expensive capital or otherwise, will impair their ability to execute this strategy.

KMP's and EPB's growth strategies may cause difficulties integrating and constructing new operations and they may not be able to achieve the expected benefits from any future acquisitions.

Part of KMP's and EPB's business strategy includes acquiring additional businesses, expanding existing assets and constructing new facilities. If they do not successfully integrate acquisitions, expansions or newly constructed facilities, anticipated operating advantages and cost savings may not occur. The integration of companies that have previously operated separately involves a number of risks, including (i) demands on management related to the increase in its size after an acquisition, expansion or completed construction project; (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; (iv) difficulties in the assimilation and retention of necessary employees; and (v) potential adverse effects on operating results.

Our limited partnerships 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, expansion or construction project will depend upon their ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining and expanding operations, cost savings and other size-related benefits they expected may not be achieved, which could harm their financial condition and results of operations.

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

As of December 31, 2013, we had approximately $34 billion of consolidated debt (including KMP and EPB, but excluding debt fair value adjustments). This level of debt 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) 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; (iii) placing us at a competitive disadvantage compared to competitors with less debt; and (iv) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our 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 operating results are not sufficient to service our indebtedness, or any future indebtedness that we incur, we will be forced to take actions which may include 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 affect 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 large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2013, approximately $8 billion (25%) of our approximately $34 billion consolidated debt (including KMP and EPB, but excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term debt of 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 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. 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.

There is the potential for a change of control of the general partners of KMP and EPB if we default on debt .

We own all of the common equity of the general partners of KMP and EPB. If we default on debt, then the lenders under such debt, in exercising their rights as lenders, could acquire control of the general partners of KMP and EPB through their control of us. A change of control of the general partners of KMP and EPB could materially adversely affect the distributions we receive from KMP and EPB, which could have a material adverse impact on us or our cash available for dividends to our stockholders.

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 could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. 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 business, financial condition and results of operations.

In addition, any reduction in our credit ratings could negatively impact the credit ratings of our subsidiaries, which could increase their cost of capital and negatively affect their business and operating results. 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 instruments, as well as the market value of KMP's and EPB's common units.

Current or future distressed financial conditions of our customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers are experiencing, or may experience in the future severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, 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.

*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 assets might be specific targets of terrorist organizations or "cyber security" events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets, our operations could be disrupted and/or customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation or litigation and or inaccurate information reported from our operations.

There is no assurance that adequate 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.

Our pipelines business is dependent on the supply of and demand for the commodities transported by our pipelines.

Our pipelines depend on production of natural gas, oil and other products in the areas served by our pipelines. Without reserve additions, 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 gas plants and pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at levels that encourages 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 a decline in crude oil or natural gas prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from oil and natural gas producing areas. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil and natural gas. Each of these factors impact our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

Throughput on KMP's and/or EPB's pipelines also may decline as a result of changes in business conditions. Over the long term, business will depend, in part, on the level of demand for oil, natural gas and refined petroleum products in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand.

The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas, crude oil and refined petroleum products, 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 demand for natural gas, crude oil and refined petroleum products.

The future success of KMP's oil and gas development and production operations depends in part upon its 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 and revenues of the oil and gas producing assets within the CO_2-KMP business segment will decline. KMP 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 KMP does not realize production volumes greater than, or equal to, its hedged volumes, it may suffer financial losses not offset by physical transactions.

KMP's 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.

The volatility of natural gas and oil prices could have a material adverse effect on the CO_2-KMP business segment.

The revenues, profitability and future growth of the CO_2-KMP business segment and the carrying value of its oil, NGL and natural gas properties depend to a large degree on prevailing oil and gas prices. For 2014, KMP estimates that every $1 change in the average WTI crude oil price per barrel would impact the CO_2-KMP segment's cash flows by approximately $7 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 KMP's 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 stability 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.

A sharp decline in the prices of oil, NGL or natural gas would result in a commensurate reduction in KMP's revenues, income and cash flows from the production of oil, NGL, and natural gas and could have a material adverse effect on the carrying value of KMP's proved reserves. In the event prices fall substantially, KMP may not be able to realize a profit from its production 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."

Our use of hedging arrangements could result in financial losses or reduce our income.

We engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil 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 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 always possible for us to engage in hedging transactions that completely mitigate 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.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission, referred to as 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 and also comply with margin requirements in connection with our derivatives activities that are not exchange traded, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act also requires many counterparties to our derivatives instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with the capital requirements, which could result in increased costs to counterparties such as us. The Dodd-Frank Act and any related regulations could (i) significantly increase the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduce the availability of derivatives to protect against risks we encounter; and (iii) reduce 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 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 Kinder Morgan Canada-KMP segment is 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 the Kinder Morgan Canada-KMP business segment, a portion of our consolidated assets, liabilities, revenues 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.

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 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, such as the challenges that are currently affecting economic conditions in the U.S. and Canada. Volatility in commodity prices might have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. In addition, decreases in the prices of crude oil and NGL will have a negative impact on the results of the CO_2-KMP business segment. 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.

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 areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage or destroy our pipelines, terminals and other assets and disrupt the supply of the products we transport through our pipelines. 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.

KMP's and EPB's tax treatment depends on their status as partnerships for U.S. federal income tax purposes, as well as not being subject to a material amount of entity-level taxation by individual states. If KMP and/or EPB were treated as corporations for U.S. federal income tax purposes or if they were to become subject to a material amount of entity-level taxation for state tax purposes, then cash available for distribution to their partners, including us, would be substantially reduced.

We own the general partner interests in both KMP and EPB and approximately 11% and 41% of the limited partner interests of KMP and of EPB, respectively. The anticipated after-tax economic benefit of our investment in KMP and EPB depends largely on their treatment as partnerships for U.S. federal income tax purposes. Neither KMP nor EPB has requested nor plans to request a ruling from the IRS on this or any other tax matter.

Despite the fact that KMP and EPB are organized as limited partnerships under Delaware law, it is possible in certain circumstances for partnerships such as KMP or EPB to be treated as corporations for U.S. federal income tax purposes. Although neither KMP nor EPB believes, based on its current operations, that it is or will be so treated, the IRS could disagree with the positions KMP or EPB takes or a change in KMP's or EPB's business (or a change in current law) could cause them to be treated as corporations for U.S. federal income tax purposes or otherwise subject them to taxation as an entity.

If they were treated as corporations for U.S. federal income tax purposes, they would pay U.S. federal income tax on taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income taxes at varying rates. Distributions by KMP and EPB to their partners, including us, would generally be taxed again as corporate dividends (to the extent of their current and accumulated earnings and profits) and no income, gains, losses, deductions or credits would flow through to their partners, including us. Because tax would be imposed on KMP and EPB as corporations, their after-tax cash available for distribution would be substantially reduced, likely causing a substantial reduction in the dividends we could pay and in the value of our common stock.

The present U.S. federal income tax treatment of publicly traded partnerships, including KMP and EPB, or an investment in them may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Moreover, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that could affect the tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these changes or other proposals will ultimately be enacted.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Any state income taxes imposed upon KMP or EPB as entities would reduce their cash available to be distributed to us. Any modification to the U.S. federal income or state tax laws, or interpretations thereof, may be applied retroactively and could negatively impact the value of our investment in KMP and EPB.

KMP's and EPB's partnership agreements provide that if a law is enacted that subjects them to corporate taxation or otherwise subjects them to entity-level taxation for U.S. federal income tax purposes, the minimum quarterly distribution amounts and the target distribution amounts will be adjusted to reflect the impact.

If KMP's or EPB's unitholders remove their respective general partner, we would lose our general partner interest in either KMP or EPB, including the right to incentive distributions, and the ability to manage them.

We own the general partners of KMP and EPB and with respect to KMP, all of the voting shares of KMR, to which the general partner has delegated its rights and powers to control the business and affairs of KMP, subject to the approval of the general partner for certain actions. KMP's and EPB's partnership agreements, however, give their respective unitholders the right to remove their general partner if (i) the holders of 66 2⁄3% of the respective partnership's outstanding units (including the common units, Class B units and i-units, as applicable) voting as a single class vote for such removal; (ii) the holders of KMP's and EPB's outstanding units approve the election and succession of a new general partner by the same vote, respectively; and

(iii) KMP and/ or EPB receives opinion of counsel that the removal and succession of the general partner would not result in the loss of the limited liability of any limited partner or its operating partnership subsidiaries or cause either KMP or EPB or its operating partnership subsidiaries to be taxed as a corporation for federal income tax purposes.

If KMP's or EPB's unitholders removed their respective general partner, the general partner would lose its ability to manage KMP or EPB, and with respect to KMP, the delegation of authority to KMR by KMP's general partner would terminate at the same time. The general partner would receive cash or common units in exchange for its general partner interest. While the cash or common units the general partner would receive are intended under the terms of KMP's and EPB's partnership agreements to fully compensate us, as the owner of the general partner, in the event such an exchange is required, the value of the investments we might make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the related incentive distributions had the general partner retained its general partner interest.

If in the future KMR and the general partner cease to manage and control KMP, with respect to KMP and EPB's general partner ceases to manage and control EPB either limited partnership may be deemed to be an investment company under the Investment Company Act of 1940.

If our subsidiaries, KMR and KMGP, which is the general partner of KMP, cease to manage and control KMP, or, El Paso Pipeline GP, L.L.C. ceases to manage and control EPB, either or both KMP and EPB may be deemed to be investment companies under the Investment Company Act of 1940. In that case, KMP and/or EPB would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify their organizational structure or contractual rights so as to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and could adversely affect the price of our common stock.

If we are unable to retain our executive officers, our growth may be hindered.

Our success depends in part on the performance of and our ability to retain our executive officers, particularly our Chairman and Chief Executive Officer, Richard D. Kinder, who is also one of our founders. Along with the other members of our senior management, Mr. Kinder has been responsible for developing and executing our growth strategy since 1997. If we are not successful in retaining Mr. Kinder 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.

Risks Related to the Ownership of Our Common Stock

The price of the common stock may be volatile, and holders of our common stock could lose a significant portion of their investments.

The market price of the common stock could be volatile, and our stockholders may not be able to resell their common stock at or above the price at which they purchased the common stock due to fluctuations in the market price of the common stock, including changes in price caused by factors unrelated to our operating performance or prospects.

Specific factors that may have a significant effect on the market price for the common stock include: (i) changes in stock market analyst recommendations or earnings estimates regarding the common stock, the common units of KMP and EPB, other companies comparable to us or KMP and EPB or companies in the industries we serve; (ii) actual or anticipated fluctuations in our operating results or future prospects; (iii) reaction to our public announcements; (iv) strategic actions taken by us or our competitors, such as acquisitions or restructurings; (v) the recruitment or departure of key personnel; (vi) new laws or regulations or new interpretations of existing laws or regulations applicable to our business and operations; (vii) changes in tax or accounting standards, policies, guidance, interpretations or principles; (viii) adverse conditions in the financial markets or general U.S. or international economic conditions, including those resulting from war, incidents of terrorism and responses to such events; (ix) sales of common stock by us, members of our management team or significant stockholders; and (x) the extent of analysts' interest in following our company.

Non-U.S. holders of our common stock may be subject to U.S. federal income tax with respect to gain on the disposition of our common stock.

If we are or have been a ''U.S. real property holding corporation'' within the meaning of the Code at any time within the shorter of (i) the five-year period preceding a disposition of our common stock by a non-U.S. holder, or (ii) such holder's holding period for such common stock, and assuming our common stock is ''regularly traded,'' as defined by applicable U.S. Treasury regulations, on an established securities market, the non-U.S. holder may be subject to U.S. federal income tax with respect to gain on such disposition if it held more than 5% of our common stock during the shorter of periods (i) and (ii) above. We believe we are, or may become, a U.S. real property holding corporation.

Risks Related to Our Dividend Policy

Holders of our common stock may not receive the anticipated level of dividends under our dividend policy or any dividends at all.

Our dividend policy provides that, subject to applicable law, we will pay quarterly cash dividends generally representing the cash we receive from our subsidiaries less any cash disbursements and reserves established by a majority vote of our board of directors, including for general and administrative expenses, interest and cash taxes. However, our board of directors, subject to the requirements of our bylaws and other governance documents, may amend, revoke or suspend our dividend policy at any time, and even while the current policy is in place, the actual amount of dividends on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, market opportunities, capital requirements of our subsidiaries, legal, regulatory and contractual constraints, tax laws and other factors. Dividends other than as provided in our dividend policy require supermajority board approval while the Sponsor Investors maintain prescribed ownership thresholds.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of any dividends we may pay in the future. The terms of any future indebtedness we incur also may restrict us from paying cash dividends on our stock under certain circumstances. A decline in the market price or liquidity, or both, of our common stock could result if our board of directors establishes large reserves that reduce the amount of quarterly dividends paid or if we reduce or eliminate the payment of dividends. This may in turn result in losses by our stockholders, which could be substantial.

The general partners of KMP and EPB, with our consent but without the consent of our stockholders, may take steps to support KMP and EPB that have the effect of reducing cash we have or are entitled to receive, thereby reducing the cash we have available to pay dividends.

We utilize KMP and EPB as our vehicles for growth. We have historically received a significant portion of our cash flows from incentive distributions on the general partner interest. As the owner of the general partner of KMP, and now EPB, we may take steps we judge beneficial to KMP's and EPB's growth that in the short-run reduce the cash we receive and have available to pay dividends. The board of directors of the general partner of KMP or EPB may determine to support a desirable acquisition that may not be immediately accretive to cash available for distribution per KMP or EPB unit. For example, KMP's general partner, with our consent, waived its incentive distributions from the second quarter of 2010 through 2011 on common units issued to finance a portion of KMP's acquisition of the initial 50% interest in the KinderHawk joint venture and has agreed to waive its paid incentive distributions of $27 million and $4 million for 2012 and the first quarter of 2013, respectively, on common units issued to finance a portion of KMP's subsequent acquisition of the remaining 50% interest in the KinderHawk joint venture. In addition, in connection with KMP's acquisition of Copano, KMP's general partner has agreed to waive incentive distributions of $75 million for 2013, $120 million for both 2014 and 2015, $110 million for 2016 and annual amounts thereafter decreasing by $5 million per year from this level.

Our dividend policy may limit our ability to pursue growth opportunities above the limited partnership level or impair our financial flexibility.

If we pay dividends at the level currently anticipated under our dividend policy, we may not retain a sufficient amount of cash to finance growth opportunities above the limited partnership level, meet any large unanticipated liquidity requirements or fund our operations in the event of a significant business downturn. In addition, because of the dividends required under our dividend policy, our ability to pursue any material expansion of our business above the limited partnership level, including through acquisitions, increased capital spending or other increases of our expenditures, will depend more than it otherwise would on our ability to obtain third party financing. We cannot assure our stockholders that such financing will be available to us at all, or at an acceptable cost. If we are unable to take timely advantage of growth opportunities, our future financial condition and competitive position may be harmed, which in turn may adversely affect the market price of our common stock.

If we do not receive sufficient distributions from our subsidiaries, we may be unable to pay dividends.

All of our operations are conducted by our subsidiaries, and our cash flow and our ability to satisfy obligations and to pay dividends to our stockholders are dependent upon cash dividends and distributions or other transfers from our subsidiaries. In addition, our joint ventures and some of our subsidiaries, such as our limited partnerships, are not wholly owned by us. When funds are distributed to us by such joint ventures and subsidiaries, funds also will be distributed to their other owners.

Each of our subsidiaries is a distinct legal entity and has no obligation to transfer funds to us. A number of our subsidiaries are a party to credit facilities and are or may in the future be a party to other borrowing agreements that restrict the payment of dividends to us, and such subsidiaries are likely to continue to be subject to such restrictions and prohibitions for the foreseeable future. In addition, the ability of our subsidiaries to make distributions will depend on their respective operating results and may be subject to further restrictions under, among other things, the laws of their jurisdiction of organization.

The board of directors of KMR, which is the delegate of KMP's general partner, and EPB's general partner have broad authority to establish cash reserves for the prudent conduct of their businesses. The establishment of those reserves could result in smaller distributions to us and a corresponding reduction of our cash available for dividends and our anticipated dividend level. Further, the calculation of KMP's and EPB's available cash for distribution is discretionary and subject to the approval of the board of directors of KMR or EPB's general partner, respectively taking into consideration their constituent agreements. Similarly, while the constituent agreements of NGPL provide that it is the intention of NGPL to make distributions of available cash, we own less than a majority of NGPL and do not control it. The same is true for joint ventures in which our limited partnerships own an interest.

The distributions we receive from KMP are largely attributable to the incentive distributions on our general partner interest. The distributions we receive are not as large if KMP distributes cash from interim capital transactions rather than cash from operations, or if KMP's general partner waives receipt of a portion of those incentive distributions.

As a result of the foregoing, we may be unable to receive cash through distributions or other payments from our subsidiaries in sufficient amounts to pay dividends on our common stock. If we are unable to authorize the payment of dividends due to insufficient cash, a decline in the market price or liquidity, or both, of our common stock could result. This may in turn result in losses by our stockholders, which could be substantial.

Our ability to pay dividends is restricted by Delaware law.

Under the DGCL, our board of directors may not authorize payment of a dividend unless it is either paid out of surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, it is paid out of net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. Our bylaws require the declaration and payment of dividends to comply with the DGCL. If, as a result of these restrictions, we are unable to authorize payment of dividends, a decline in the market price or liquidity, or both, of our common stock could result. This may in turn result in losses by our stockholders.

Risks Related to Conflicts of Interest

KMP, EPB and their subsidiaries may compete with us.

Neither of KMP, EPB or any of their subsidiaries or entities in which they own an interest is restricted from competing with us. KMR manages KMP (subject to certain decisions requiring the approval of KMP's general partner) and EPB's general partner manages EPB, in what they consider to be the best interests of their respective limited partner interests. KMP, EPB and their subsidiaries may acquire, invest in or construct assets that may be in direct competition with us, which could have a material adverse effect on our business, financial condition, results of operations or prospects. Among other things, we and our limited partnerships have a policy that acquisition opportunities of businesses or operating assets will be pursued above the limited partnership level only if KMP and EPB elect not to pursue the opportunity.

Many of our directors and officers also serve as directors or officers of our non-wholly owned subsidiaries, including KMR and EPB, or entities in which we own an interest, such as NGPL, as a result of which conflicts of interest exist and will arise in the future.

Many of our directors and officers are also directors or officers of our non-wholly owned subsidiaries. Any officer or director of our non-wholly owned subsidiaries, who is also a director or officer of ours, in making decisions in such person's capacity as our officer or director, is required to act in accordance with his or her fiduciary duties to us. However, in making decisions in such person's capacity as a director or officer of one of our non-wholly owned subsidiaries or such other entities, such person may make a decision that favors the interests of such subsidiary over our interests or the interests of our stockholders and may be to our detriment. Further, the organizational documents of these entities may have provisions reducing or eliminating the duties of their officers or directors to those entities and their owners, including us. In addition, our directors are not required to work full time on our business and affairs and may devote significant time to the affairs of our non-wholly owned subsidiaries. There could be material competition for the time and effort of our directors who provide services to our non-wholly owned subsidiaries.

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

See Note 16 "Litigation, Environmental and Other" 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.

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PART II

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

On December 26, 2012, the remaining outstanding shares of our Class A, Class B, and Class C common stock were converted into Class P shares and as of December 31, 2012 only our Class P common stock was outstanding. Our Class P common stock is listed for trading on the NYSE under the symbol "KMI." During the period that our Class A, Class B, and Class C common stock was outstanding, none were traded on a public trading market. The high and low sale prices per Class P share as reported on the NYSE and the dividends declared per share by period for 2013 and 2012, are provided below.

	Price Range		Declared Cash Dividends (a)
	Low	High	
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
2012			
First Quarter	31.76	39.25	0.32
Second Quarter	30.51	40.25	0.35
Third Quarter	32.03	36.63	0.36
Fourth Quarter	31.93	36.50	0.37

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(a) Dividend information is for dividends declared with respect to that quarter. Generally, our declared dividends are paid after we receive quarterly distributions from KMP and EPB, which are paid within 45 days after the end of each quarter.

As of January 31, 2014, we had 10,955 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

For information on our equity compensation plans, see Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Equity Compensation Plan Information." Also see Note 9 "Share-based Compensation and Employee Benefits—Share-based Compensation—Kinder Morgan, Inc." to our consolidated financial statements.

Our Purchases of Our Class P Shares and Warrants

Period	Total number of securities repurchased(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 for programs
October 1 to October 31, 2013				
Warrants	513,198	$ 5.04	513,198	$ 266,164,485
November 1 to November 30, 2013	—	$ —	—	$ 266,164,485
December 1 to December 31, 2013				
Class P Shares	5,175,055	$ 33.23	5,175,055	$ 94,140,938
Total				
Warrants	513,198	$ 5.04	513,198	
Class P Shares	5,175,055	$ 33.23	5,175,055	
				$ 94,140,938

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(a) On October 16, 2013, we announced that our board of directors had approved a separate share and warrant repurchase program, authorizing us to repurchase in the aggregate up to $250 million of additional shares and warrants. This $250 million program is in addition to the previously announced repurchase programs, including our board authorized $350 million share and warrant repurchase program that was announced on July 17, 2013.

Item 6. *Selected Financial Data.*

The following tables set forth, for the periods and at the dates indicated, our summary historical financial and operating 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,				
	2013	**2012**	**2011**	**2010**	**2009**
	(In millions, except per share and ratio data)				
Income and Cash Flow Data:					
Revenues	$ 14,070	$ 9,973	$ 7,943	$ 7,852	$ 6,879
Operating income	3,990	2,593	1,423	1,133	1,257
Earnings (loss) from equity investments	327	153	226	(274)	123
Income from continuing operations	2,696	1,204	449	64	523
(Loss) income from discontinued operations, net of tax	(4)	(777)	211	236	250
Net income	2,692	427	660	300	773
Net income (loss) attributable to Kinder Morgan, Inc.	1,193	315	594	(41)	495
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$ 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	$ 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 Shares Outstanding:					
Class P shares	1,036	461	118		
Class A shares		446	589		
Diluted Weighted Average Number of Shares Outstanding:					
Class P shares	1,036	908	708		
Class A shares		446	589		
Dividends per common share declared for the period(a)	$ 1.60	$ 1.40	$ 1.05		
Dividends per common share paid in the period(a)	1.56	1.34	0.74		
Balance Sheet Data (at end of period):					
Net property, plant and equipment	$ 35,847	$ 30,996	$ 17,926	$ 17,071	$ 16,804
Total assets	75,185	68,245	30,717	28,908	27,581
Long-term debt – KMI(b)	9,321	9,248	2,078	2,918	2,925
Long-term debt – KMP(c)	18,410	15,907	11,183	10,301	10,022
Long-term debt – EPB(d)	4,179	4,254	—	—	—

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.
(b) Excludes debt fair value adjustments. Increases (decreases) to long-term debt for debt fair value adjustments for KMI and its subsidiaries (excluding KMP, EPB and their respective subsidiaries) totaled $771 million, $901 million, $40 million, $12 million and $(14) million as of December 31, 2013, 2012, 2011, 2010 and 2009, respectively.
(c) Excludes debt fair value adjustments. Increases to long-term debt for debt fair value adjustments totaled $1,214 million, $1,698 million, $1,055 million, $582 million and $308 million as of December 31, 2013, 2012, 2011, 2010 and 2009, respectively.
(d) Excludes debt fair value adjustments. Decrease to long-term debt for debt fair value adjustments totaled $8 million as of both December 31, 2012 and 2013.

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. 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 2013, 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."

We prepared our consolidated financial statements in accordance with GAAP. Accordingly, as discussed in Notes 1 "General", 2 "Summary of Significant Accounting Policies", and 3 "Acquisitions and Divestitures" to our consolidated financial statements, our financial statements reflect the reclassifications necessary to reflect the results of KMP's FTC Natural Gas Pipelines disposal group as discontinued operations. We sold KMP's FTC Natural Gas Pipelines disposal group to Tallgrass effective November 1, 2012 for approximately $1.8 billion in cash (before selling costs), or $3.3 billion including KMP's share of joint venture debt. In 2013, KMP and Tallgrass trued up the final consideration for the sale of KMP's FTC Natural Gas Pipelines disposal group and based both on this true up and certain incremental selling expenses KMP paid in 2013, we recognized an additional $4 million loss related to our sale of the disposal group. Except for this loss amount, we recorded no other financial results from the operations of the disposal group during 2013. Furthermore, we have excluded the disposal group's financial results from the Natural Gas Pipelines business segment disclosures for each of the years ended December 31, 2012 and 2011.

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 components:

- 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—(i) the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems; (ii) the ownership and/or operation of associated natural gas gathering systems and natural gas processing and treating facilities; and (iii) the ownership and/or operation of NGL fractionation facilities and transportation systems;

- CO_2-KMP—(i) the production, transportation and marketing of CO_2, to oil fields that use CO_2 to increase production of oil; (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;

- Products Pipelines-KMP— 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;

- Terminals-KMP—the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the U.S. and portions of Canada;

- Kinder Morgan Canada-KMP—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 includes several physical natural gas contracts with power plants associated with EP's legacy trading activities. These contracts obligate EP to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028.

As an energy infrastructure owner and operator in multiple facets of the U.S.' and Canada's various energy businesses 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 and related storage facilities, 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, in KMP's Texas Intrastate Natural Gas Group, it currently derives approximately 75% of its sales and transport margins from long-term transport and sales contracts that include requirements with minimum volume payment obligations. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2013, the remaining average contract life of our natural gas transportation contracts (including intrastate pipelines' purchase and sales contracts) was approximately five and a half years.

During 2012 and 2013, we further expanded our midstream services through our (i) EP midstream asset operations, which we acquired 50% from KKR effective June 1, 2012, and 50% from the May 25, 2012 EP acquisition; and (ii) our Copano operations, which included the remaining 50% ownership interest in Eagle Ford Gathering LLC that we did not already own and which was acquired effective May 1, 2013. These fee-based gathering, processing and fractionation assets, along with our financial strength and extensive pipeline transportation and storage assets, should provide an excellent platform to further grow our midstream services footprint. 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 also affected by the volumes of natural gas made available to our systems, which are primarily driven by levels of natural gas drilling activity. Our midstream services are provided pursuant to a variety of arrangements, generally categorized (by the nature of the commodity price risk) as fee-based, percent-of-proceeds, percent-of-index and keep-whole. 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 sales and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2013, had a remaining average contract life of approximately ten 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 2014, and utilizing the average oil price per barrel contained in our 2014 budget, approximately 69% of our contractual volumes are based on a fixed fee or floor price, and 31% fluctuate with the price of oil. In the long-term, our success in this portion of the CO_2-KMP 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-KMP 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 $92.70 per barrel in 2013, $87.72 per barrel in 2012 and $69.73 per barrel in 2011. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $94.94 per barrel in 2013, $89.91 per barrel in 2012 and $92.61 per barrel in 2011.

The profitability of our refined petroleum products pipeline transportation business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. Transportation 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.

The factors impacting the Terminals-KMP 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. 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 have minimum volume guarantees and are volume based above the minimums. Because these contracts are volume based above the minimums, our profitability from the bulk business can be sensitive to economic conditions. 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. 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.

In 2013, KMI completed the drop-down of its remaining 50% interest in EPNG and its 50% interest in the EP midstream assets to KMP. KMI used proceeds from the drop-down transaction to (i) pay down $947 million of KMI's senior secured term loan facility; and (ii) reduce borrowings under KMI's credit facility. In 2014, KMI expects to drop-down its 50% interest in Ruby Pipeline Holding Company, L.L.C., its 50% interest in Gulf LNG Holdings Group, LLC and its 47.5% interest in Young Gas Storage Company, LTD to EPB. KMP and EPB have a successful history of making accretive acquisitions and economically advantageous expansions of existing businesses.

Thus, the amount that we are able to increase dividends to our shareholders will, to some extent, be a function of our and our subsidiaries' ability to complete successful acquisitions and expansions (including drop-down transactions). We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately $3.9 billion for our 2014 capital expansion program (including small acquisitions and investment contributions). We and our subsidiaries, KMP and EPB, regularly consider and enter into discussions regarding potential acquisitions, including those from us or our affiliates, and are currently contemplating potential acquisitions.

Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict. 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. Furthermore, our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

Our, or our subsidiaries' (including EPB and KMP), ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As MLPs, KMP and EPB distribute all of their available cash, and they access capital markets to fund acquisitions and asset expansions. Historically, KMP and EPB have succeeded in raising necessary capital in order to fund their acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that KMP's and EPB's stable cash flows, credit ratings, and historical records of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, including KMP's and EPB's public debt and equity offerings in 2013, please see "—Liquidity and Capital Resources" below.

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.

In addition, a portion of KMP's business portfolio (including the Kinder Morgan Canada-KMP business segment, the Canadian portion of KMP's Cochin Pipeline, and the bulk and liquids terminal facilities located in Canada) uses the local Canadian dollar as the functional currency for its Canadian operations and enters into foreign currency-based transactions, both of which affect segment results due to the inherent variability in U.S. - Canadian dollar exchange rates. To help understand our reported operating results, all of the following references to "foreign currency effects" or similar terms in this section represent our estimates of the changes in financial results, in U.S. dollars, resulting from fluctuations in the relative value of the Canadian dollar to the U.S. dollar. The references are made to facilitate period-to-period comparisons of business performance and may not be comparable to similarly titled measures used by other registrants.

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 recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values (with limited exceptions) 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 Item 1(c). For more information on our environmental disclosures, see Note 16 "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.

As of December 31, 2013, our most significant ongoing legal matters involved KMP's West Coast Products Pipelines and its Western Interstate Natural Gas Pipelines. Transportation rates charged by certain of these pipeline systems are subject to proceedings at the FERC and the CPUC involving shipper challenges to the pipelines' interstate and intrastate (California) rates, respectively. For more information on regulatory proceedings, see Note 16 "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 our goodwill for impairment on May 31 of each year. There were no impairment charges resulting from our May 31, 2013 impairment testing, and no event indicating an impairment has occurred subsequent to that date. Furthermore, our analysis as of that date did not reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets. For more information on our goodwill, see Notes 2 "Summary of Significant Accounting Policies" and 7 "Goodwill and Other Intangibles" to our consolidated financial statements.

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 amortizable intangibles, see Note 7 “Goodwill and Other Intangibles” 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)”.

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.

Since it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to unfavorable changes in commodity prices-a perfectly effective hedge-we often enter into hedges that are not completely effective in those instances where we believe to do so would be better than not hedging at all. But because the part of such hedging transactions that is not effective in offsetting undesired changes in commodity prices (the ineffective portion) is required to be recognized currently in earnings, our 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 example, when we purchase a commodity at one location and sell it at another, we may be unable to hedge completely our exposure to a differential in the price of the product between these two locations; accordingly, our financial statements may reflect some volatility due to these hedges. For more information on our hedging activities, see Note 13 “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, 2013, our pension plans were underfunded by $230 million and our other postretirement benefits plans were underfunded by $251 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. We select 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 9 “Share-based Compensation and Employee Benefits” to our consolidated financial statements.

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. We record these deferred amounts as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations. As of December 31, 2013, we had deferred net losses of approximately $27 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, 2013:

	Pension Benefits		Other Postretirement Benefits	
	Net benefit cost (income)	Change in funded status and pretax accumulated other comprehensive income (loss)	Net benefit cost (income)	Change in funded status and pretax accumulated other comprehensive income (loss)
	(In millions)			
One percent increase in:				
Discount rates	$ 13	$ 226	$ 1	$ 54
Expected return on plan assets	(22)	—	(3)	—
Rate of compensation increase	2	(9)	—	—
Health care cost trends	—	—	3	(45)
One percent decrease in:				
Discount rates	4	(269)	(1)	(63)
Expected return on plan assets	22	—	3	—
Rate of compensation increase	(2)	8	—	—
Health care cost trends	—	—	(3)	39

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 including our investment in KMP and EPB. 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 investment in KMP and EPB.

Going Private Transaction

A Going Private Transaction completed in May 2007 was accounted for as a purchase business combination. Accordingly, our assets and liabilities were recorded at their estimated fair values as of the date of the completion of the Going Private Transaction, with the excess of the purchase price over these combined fair values recorded as goodwill.

Results of Operations

Non-GAAP Measures

The non-GAAP, financial measures of (i) cash available to pay dividends, both in the aggregate and per share, and (ii) segment EBDA and certain items are presented below under "—Cash Available to Pay Dividends" and "—Consolidated Earnings Results." 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.

We believe the GAAP measure most directly comparable to cash available to pay dividends is income from continuing operations. A reconciliation of cash available to pay dividends to income from continuing operations is provided below under "—Reconciliation of Cash Available to Pay Dividends to Income from Continuing Operation." Our non-GAAP measures below should not be considered as an alternative to GAAP net income or any other GAAP measure. Cash available to pay dividends and segment EBDA and certain items are not financial measures in accordance with GAAP and have important limitations as analytical tools. You should not consider these non-GAAP measures in isolation or as a substitute for an analysis of our results as reported under GAAP. Our computation of cash available to pay dividends and segment EBDA and certain items may differ from similarly titled measures used by others. 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.

Cash Available to Pay Dividends

Our board of directors has adopted the dividend policy set forth in our shareholders' agreement, which provides that, subject to applicable law, we will pay quarterly cash dividends on all classes of our capital stock equal to the cash we receive from our subsidiaries and other sources less any cash disbursements and reserves established by a majority vote of our board of directors, including for general and administrative expenses, interest and cash taxes. See a further discussion on KMI dividends below under "— Financial Condition— KMI Dividends." The calculation of our cash available to pay dividends, and a reconciliation of this non-GAAP measure to income from continuing operations, for each of the years ended December 31, 2013, 2012 and 2011 is as follows:

Cash Available to Pay Dividends
(In millions, except per share amounts)

	Year Ended December 31,		
	2013	2012	2011
KMP distributions to us			
From ownership of general partner interest (a)	$ 1,756	$ 1,454	$ 1,217
On KMP units owned by us (b)	147	120	100
On KMR shares owned by us (c)	83	73	63
Total KMP distributions to us	1,986	1,647	1,380
EPB distributions to us			
From ownership of general partner interest (d)	211	118	—
On EPB units owned by us (e)	230	157	—
Total EPB distributions to us	441	275	—
Cash generated from KMP and EPB	2,427	1,922	1,380
General and administrative expenses and other (f)	(50)	(35)	(9)
Interest expense	(132)	(181)	(167)
Cash taxes (g)	(516)	(419)	(368)
Cash available for distribution to us from KMP and EPB	1,729	1,287	836
Cash available from other assets			
Cash generated from other assets (h)	375	439	30
EP debt assumed interest expense (i)	(316)	(235)	—
EP acquisition debt interest expense (j)	(75)	(80)	—
Cash available for distribution to us from other assets	(16)	124	30
Cash available to pay dividends (k)	$ 1,713	$ 1,411	$ 866
Weighted-Average Shares Outstanding for Dividends (l)	1,040	908	708
Cash Available Per Average Share Outstanding	$ 1.65	$ 1.55	$ 1.22
Declared Dividend	$ 1.60	$ 1.40	$ 1.05

(a) Based on (i) KMP distributions of $5.33, $4.98 and $4.61 per common unit declared for the years ended December 31, 2013, 2012 and 2011, respectively; (ii) 381 million, 340 million and 319 million aggregate common units, Class B units and i-units (collectively KMP units) outstanding as of April 29, 2013, April 30, 2012 and April 29, 2011, respectively; (iii) 433 million, 347 million and 330 million KMP units outstanding as of July 31, 2013, July 31, 2012 and July 29, 2011, respectively; (iv) 438 million, 365 million and 333 million KMP units outstanding as of October 31, 2013, 2012 and 2011, respectively; (v) 444 million, 373 million and 336 million KMP units outstanding as of January 31, 2014, 2013 and 2012, respectively, and (vi) waived incentive distributions of $4 million, $26 million and $29 million for the years ended December 31, 2013, 2012 and 2011, respectively related to KMP's acquisition of its initial 50% interest in May 2010, and subsequently, the remaining 50% interest in May 2011 of KinderHawk; and (vii) waived incentive distribution of $75 million for the year ended December 31, 2013, as a result of KMP's acquisition of Copano. In addition, we as general partner of KMP, agreed to waive a portion of our future incentive distributions amounts equal to (i) $120 million for 2014, $120 million for 2015, $110 million for 2016, and annual amounts thereafter decreasing by $5 million per year from the 2016 level related to the Copano acquisition and (ii) $13 million for 2014, $19 million for 2015 and $6 million for 2016 related to KMP's APT and SCT acquisitions.

(b) Based on 28 million in 2013, 26 million as of September 30 and December 31, 2012 and 22 million in the prior periods, KMP units owned by us, multiplied by the KMP per unit distribution declared, as outlined in footnote (a) above.

(c) Assumes that we sold the KMR shares that we received as distributions for the years ended December 31, 2013, 2012 and 2011. We did not sell any KMR shares in 2013, 2012 or 2011. We intend periodically to sell the KMR shares we receive as distributions to generate cash.

(d) Based on (i) EPB distributions of $2.55 and $1.74 per common unit declared for the year ended December 31, 2013 and the nine months ended December 31, 2012; (ii) 216 million common units outstanding as of April 29, 2013; (iii) 218 million and 208 million common units outstanding as of July 31, 2013 and 2012, respectively; (iv) 218 million and 216 million outstanding as of October 31, 2013 and 2012, respectively; and (v) 218 million and 216 million common units outstanding as of January 31, 2014 and 2013, respectively.

(e) Based on 90 million EPB units owned by us as of December 31, 2013 and 2012, multiplied by the EPB per unit distribution declared, as outlined in footnote (d) above.

(f) Represents corporate general and administrative expenses, corporate sustaining capital expenditures, and other income and expense.

(g) 2013 and 2012 Cash taxes were calculated based on the income and expenses included in the table, deductions related to the income included, and use of net operating loss carryforwards of $300 million and $200 million, respectively.

(h) Represents cash available from former EP assets that remain at KMI, including TGP, EPNG and El Paso midstream assets for the periods presented prior to their drop-down to KMP, and our 20% interest in NGPL, net of general and administrative expenses related to KMI's EP assets. Cash available includes our share (if applicable) of pre-tax earnings, plus DD&A, and less cash taxes and sustaining capital expenditures.

(i) Represents interest expense on debt assumed from the May 25, 2012 EP acquisition.

(j) Represents interest associated with Kinder Morgan, Inc.'s (KMI) remaining debt issued to finance the cash portion of EP acquisition purchase price.

(k) Excludes $310 million in after-tax expenses associated with the EP acquisition and EP Energy sale for the year ended December 31, 2012. This included (i) $101 million in employee severance, retention and bonus costs; (ii) $55 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory fees; (iv) $68 million write-off associated with the EP acquisition (primarily due to debt repayments) or amortization of capitalized financing fees; (v) $51 million for legal fees and reserves, net of recoveries; and (vi) $19 million benefit associated with pension income.

(l) Includes weighted average common stock outstanding and (i) for 2013, approximately 6 million of unvested restricted stock awards issued to management employees that contain rights to dividends and (ii) for 2012, Class B shares, Class C shares and unvested restricted stock awards.

Reconciliation of Cash Available to Pay Dividends from Income from Continuing Operations
(In millions)

	Year Ended December 31,		
	2013	**2012**	**2011**
Income from continuing operations (a)	$ 2,696	$ 1,204	$ 449
Income from discontinued operations, net of tax (a) (b)	—	160	211
Income attributable to EPB (c)	—	(37)	—
Distributions declared by EPB for the second quarter and payable in the third quarter of 2012 to KMI (c)	—	82	—
DD&A (a) (d)	1,806	1,426	1,092
Amortization of excess cost of equity investments (a)	39	23	7
Earnings from equity investments (e)	(392)	(423)	(313)
Distributions from equity investments	398	381	287
Distributions from equity investments in excess of cumulative earnings	185	200	236
Difference between equity investment DCF and distributions received (f)	157	160	4
KMP certain items (g)	(559)	92	493
KMI certain items (h)	55	682	(2)
KMI deferred income tax adjustments (i)	—	(57)	—
Difference between cash and book taxes	105	(264)	(32)
Difference between cash and book interest expense for KMI	14	23	(1)
Sustaining capital expenditures (j)	(405)	(393)	(213)
KMP declared distribution on its limited partner units owned by the public (k)	(2,031)	(1,583)	(1,357)
EPB declared distribution on its limited partner units owned by the public (l)	(324)	(214)	—
Other (m)	(31)	(51)	5
Cash available to pay dividends	**$ 1,713**	**$ 1,411**	**$ 866**

(a) Consists of the corresponding line items in our consolidated statements of income.

(b) 2012 and 2011 amounts primarily represent income from KMP's FTC Natural Gas Pipelines disposal group, net of tax.

(c) On May 25, 2012, we began recognizing income from our investment in EPB, and we received in the third quarter the full distribution for the second quarter as we were the holder of record as of July 31, 2012.

(d) 2012 and 2011 amounts include $7 million and $24 million, respectively, associated with KMP's FTC Natural Gas Pipelines disposal group.

(e) 2013 and 2012 amounts exclude $65 million and $200 million, respectively, non-cash impairment charges on our investment in NGPL Holdco LLC. 2012 and 2011 amounts include $70 million and $87 million, respectively, associated with KMP's FTC Natural Gas Pipelines disposal group.

(f) Consists of the difference between cash available for distributions and the distributions received from our equity investments.

(g) Consists of items such as hedge ineffectiveness, legal and environmental reserves, gain/loss on sale, insurance proceeds from casualty losses, and asset acquisition and/or disposition expenses. 2013 amount includes (i) $558 million gain on remeasurement of previously held equity interest in Eagle Ford Gathering to fair value; (ii) $177 million for legal reserves related to the rate case and other litigation and environmental matters on KMP's west coast Products Pipelines; and (iii) $140 million, net of tax, gain on the sale of Express. 2011 amount includes (i) $167 million non-cash loss on remeasurement of KMP's previously held equity interest in KinderHawk to fair value; (ii) $234 million increase to KMP's legal reserve attributable to rate case and other litigation involving KMP's products pipelines on the West Coast and (iii) KMP's portion ($87 million) of a $100 million special bonus expense for non-senior employees, which KMP is required to recognize in accordance with GAAP. However, KMP had no obligation, nor did it pay any amounts in respect to such bonuses. The cost of the $100 million special bonus to non-senior employees was not borne by our Class P shareholders. In May of 2011 we paid for the $100 million of special bonuses, which included the amounts allocated to KMP, using $64 million (after-tax) in available earnings and profits reserved for this purpose and not paid in dividends to our Class A shareholders.

(h) 2013 and 2012 amounts include NGPL Holdco LLC non-cash impairment charges discussed above in footnote (e). 2012 amount also represents pre-tax (income) expense associated with the EP acquisition and EP Energy sale including (i) $160 million in employee severance, retention and bonus costs; (ii) $87 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory fees; (iv) $108 million write-off (primarily due to repayments) or amortization of capitalized financing fees; (v) $68 million for legal fees and reserves, net of recoveries; and (vi) $29 million benefit associated with pension income.

(i) 2012 amounts represent an increase in our state effective tax rate as a result of the EP acquisition.

(j) We define sustaining capital expenditures as capital expenditures which maintain the capacity or throughput of an asset.

(k) Declared distribution multiplied by limited partner units outstanding on the applicable record date less units owned by us. Includes distributions on KMR shares. KMP must generate the cash to cover the distributions on the KMR shares, but those distributions are paid in additional shares and KMP retains the cash. We do not have access to that cash.

(l) Declared distribution multiplied by EPB limited partner units outstanding on the applicable record date less units owned by us.

(m) Consists of items such as timing and other differences between earnings and cash, KMP's and EPB's cash flow in excess of their distributions, non-cash purchase accounting adjustments related to the EP acquisition and going private transaction primarily associated with non-cash amortization of debt fair value adjustments, and in the year ended 2011 KMP's crude hedges.

Consolidated Earnings Results

With regard to our reportable business segments, we consider segment earnings before all DD&A expenses, and amortization of excess cost of equity investments (defined in the "-Results of Operations" tables below and sometimes referred to in this report as EBDA) to be an important measure of our success in maximizing returns to our shareholders. We also use segment EBDA internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our six reportable business segments. EBDA may not be comparable to measures used by other companies. Additionally, EBDA should be considered in conjunction with net income and other performance measures such as operating income, income from continuing operations or operating cash flows.

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Segment EBDA(a)			
Natural Gas Pipelines	$ 4,207	$ 2,174	$ 563
CO_2—KMP	1,435	1,322	1,117
Products Pipelines—KMP	602	668	461
Terminals—KMP	836	708	702
Kinder Morgan Canada—KMP	340	229	202
Other	(5)	7	—
Segment EBDA(b)	7,415	5,108	3,045
DD&A expense	(1,806)	(1,419)	(1,068)
Amortization of excess cost of equity investments	(39)	(23)	(7)
Other revenues	36	35	36
General and administrative expenses(c)	(613)	(929)	(515)
Unallocable interest and other, net(d)	(1,688)	(1,441)	(701)
Income from continuing operations before unallocable income taxes	3,305	1,331	790
Unallocable income tax expense	(609)	(127)	(341)
Income from continuing operations	2,696	1,204	449
(Loss) income from discontinued operations, net of tax(e)	(4)	(777)	211
Net income	2,692	427	660
Net income attributable to noncontrolling interests	(1,499)	(112)	(66)
Net income attributable to Kinder Morgan, Inc.	$ 1,193	$ 315	$ 594

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). 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, 2013, 2012 and 2011 were $133 million, $12 million and $20 million, respectively.

(b) 2013 amount includes an increase in earnings of $489 million, and 2012 and 2011 amounts include decreases in earnings of $285 million and $374 million, respectively, related to the combined effect from all of the 2013, 2012 and 2011 certain items impacting continuing operations and disclosed below in our management discussion and analysis of segment results.

(c) 2013 amount includes a decrease to expense of $4 million, and 2012 and 2011 amounts include increases in expense of $401 million and $127 million, respectively, related to the combined effect from all of the 2013, 2012 and 2011 certain items related to general and administrative expenses disclosed below in "-General and Administrative, Interest, and Noncontrolling Interests."

(d) 2013 and 2012 amounts include increases in expense of $30 million and $107 million, respectively, related to the combined effect from all of the 2013 and 2012 certain items related to interest expense disclosed below in "-General and Administrative, Interest, and Noncontrolling Interests."

(e) Represents amounts attributable to KMP's FTC Natural Gas Pipelines disposal group. 2013 amount represents an incremental loss related to the sale of KMP's disposal group effective November 1, 2012. 2012 amount includes a combined $937 million loss from the remeasurement of net assets to fair value and the sale of KMP's disposal group. 2011 amount includes a $10 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2012 and 2011 amounts also include depreciation and amortization expenses of $7 million and $27 million, respectively.

Year Ended December 31, 2013 vs. 2012

Our total revenues for 2013 and 2012 were $14.1 billion and $10.0 billion, respectively. Income from continuing operations before income taxes totaled $3,438 million for 2013 as compared to $1,343 million in 2012.

Our income from continuing operations before income taxes (excluding income taxes allocated to segment earnings, see footnote (a)) increased by $2,095 million (156%) from $1,343 million in 2012 to $3,438 million in 2013. However, this increase included a $1,256 million increase in income from continuing operations before income taxes from the combined effect of the certain items referenced in footnotes (b), (c) and (d) in the above table.

The remaining $839 million (39%) increase in income from continuing operations before income taxes was primarily due to better overall performance from our segments in 2013 driven by the Natural Gas Pipelines segment (primarily due to a full year of contributions from the EP operations, including EPB).

Year Ended December 31, 2012 vs. 2011

Our total revenues for 2012 and 2011 were $10.0 billion and $7.9 billion, respectively. Income from continuing operations before income taxes totaled $1,343 million for 2012 as compared to $810 million in 2011.

Our income from continuing operations before income taxes (excluding income taxes allocated to segment earnings, see footnote (a)) increased by $533 million (66%) from $810 million in 2011 to $1,343 million in 2012. However, this increase included a $292 million (pre-tax) decrease in income from continuing operations before income taxes from the combined effect of the certain items referenced in footnotes (b), (c) and (d) in the above table.

After adjusting for these items, the remaining $825 million (63%) increase in income from continuing operations before income taxes was primarily due to better performance in 2012 from all reportable business segments, driven mainly by increases attributable to the Natural Gas Pipelines, due to contributions from the EP operations, including EPB, the CO2-KMP and the Terminals-KMP business segments.

Impact of the Purchase Method of Accounting on Segment Earnings (Loss)

The impacts of the purchase method of accounting on segment earnings (loss) before DD&A relate primarily to the revaluation of the accumulated other comprehensive income related to derivatives accounted for as hedges in the CO_2—KMP and Natural Gas Pipelines segments. Where there is an impact to segment earnings (loss) before DD&A from the Going Private Transaction, the impact is described in the individual business segment discussions, which follow. The effects on DD&A expense result from changes in the carrying values of certain tangible and intangible assets to their estimated fair values as of May 30, 2007. This revaluation results in changes to DD&A expense in periods subsequent to May 30, 2007. The purchase accounting effects on "Unallocable interest and other, net" result principally from the revaluation of certain debt instruments to their estimated fair values as of May 30, 2007, resulting in changes to interest expense in subsequent periods.

Segment earnings before depreciation, depletion and amortization expenses

Certain items included in earnings from continuing operations are either not allocated to business segments or are not considered by management in its evaluation of business segment performance. In general, the items not included in segment results are interest expense, general and administrative expenses, DD&A and unallocable income taxes. These items 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 currently evaluate business segment performance primarily based on segment earnings before DD&A in relation to the level of capital employed. Because KMP's and EPB's partnership agreements require them to distribute 100% of their available cash to their partners on a quarterly basis (KMP's and EPB's available cash consists primarily of all of its cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our segments that are also segments of KMP. We account for intersegment sales at market prices. 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 income statement of the combined entity.

Natural Gas Pipelines

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except operating statistics)		
Revenues(a)	$ 8,617	$ 5,230	$ 3,943
Operating expenses	(5,235)	(3,111)	(3,370)
Other income (expense)	24	(14)	(1)
Earnings from equity investments	232	52	158
Interest income and Other, net	578	22	(164)
Income tax expense	(9)	(5)	(3)
EBDA from continuing operations(b)	4,207	2,174	563
Discontinued operations(c)	(4)	(770)	228
EBDA including discontinued operations	$ 4,203	$ 1,404	$ 791
Natural gas transport volumes (TBtu)(d)	9,634.0	10,071.9	8,961.4
Natural gas sales volumes (TBtu)(e)	897.3	879.1	804.7
Natural gas gathering volumes (BBtu/d)(f)	2,959.3	2,996.2	2,475.9

(a) 2013 amount includes a $16 million decrease related to derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales.

(b) 2013, 2012 and 2011 amounts include a $490 million increase in earnings, a $202 million decrease in earnings and $168 million decrease in earnings, respectively, related to the combined effect from certain items. 2013 amount consists of (i) a $558 million gain from the remeasurement of KMP's 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 $16 million decrease in earnings related to derivative contracts, as described in footnote (a); (iv) a $4 million decrease in EBDA related to SNG's certain items; and (v) a combined $1 million increase from other certain items. 2013 and 2012 amounts include $65 million and $200 million, respectively, non-cash equity investment impairment charges related to our 20% ownership interest in NGPL Holdco LLC. 2012 amount consists of a combined $11 million increase from other certain items. 2011 amount consists of a $167 million loss from the remeasurement of KMP's previously held 50% equity interest in KinderHawk to fair value. Also, 2013, 2012 and 2011 amounts include decreases in earnings of $20 million, $13 million, and $1 million, respectively, related to assets sold, or adjusted, that had been revalued as part of the Going Private Transaction and recorded in the application of the purchase method of accounting.

(c) Represents EBDA attributable to KMP's FTC Natural Gas Pipelines disposal group. 2013 amount represents a loss from the sale of net assets. 2012 amount includes a combined loss of $937 million from the remeasurement of net assets to fair value and the sale of net assets. 2011 amount includes a $10 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2012 and 2011 amounts also include revenues of $227 million and $322 million, respectively.

(d) Includes pipeline volumes for TransColorado Gas Transmission Company LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC, Fayetteville Express Pipeline LLC, TGP, EPNG, Copano South Texas, the Texas intrastate natural gas pipeline group, EPB, Florida Gas Transmission Company, and Ruby Pipeline, L.L.C. Volumes for acquired pipelines are included for all periods. However these contributions to EBDA are included only for the periods subsequent to their acquisition.

(e) Represents volumes for the Texas intrastate natural gas pipeline group .

(f) Includes Copano operations, EP midstream assets operations, KinderHawk, Endeavor, Bighorn Gas Gathering L.L.C., Webb Duval Gatherers, Fort Union Gas Gathering L.L.C., EagleHawk, and Red Cedar Gathering Company throughput volumes. Joint venture throughput is reported at KMP's ownership share. Volumes for acquired pipelines are included for all periods. However these contributions to EBDA are included only for the periods subsequent to their acquisition.

The certain items described in the footnotes to the table above accounted for a $1,625 million increase in our Natural Gas Pipelines business segment's EBDA (including discontinued operations) in 2013, and a $961 million decrease in segment EBDA in 2012, when compared to the respective prior year. The certain items also accounted for a $16 million decrease in segment revenues (including discontinued operations) in 2013 when compared to 2012. Following is information, including discontinued operations, related to the segment's remaining (i) $1,174 million (46%) and $1,574 million (162%) increases in EBDA and (ii) $3,176 million (58%) increase and $1,192 million (28%) increase in revenues in 2013 and 2012, when compared with the respective prior year:

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
EPB	$ 456	62 %	$ 598	66 %
TGP	358	81 %	440	73 %
EPNG	151	68 %	217	72 %
Copano operations (excluding Eagle Ford)	233	n/a	1,119	n/a
EP midstream asset operations	46	118 %	81	89 %
Eagle Ford(a)	56	166 %	419	n/a
Texas Intrastate Natural Gas Pipeline Group	16	5 %	874	31 %
KinderHawk Field Services	13	8 %	9	5 %
Kinder Morgan Treating operations	(26)	(32)%	(47)	(30)%
Citrus	32	62 %	n/a	n/a
Gulf LNG Holdings Group, LLC	21	81 %	n/a	n/a
Other KMI owned assets(b)	(11)	(275)%	n/a	n/a
All others (including eliminations)	(4)	(2)%	(307)	(263)%
Total Natural Gas Pipelines - continuing operations	1,341	56 %	3,403	65 %
Discontinued operations(c)	(167)	(100)%	(227)	(100)%
Total Natural Gas Pipelines - including discontinued operations	$ 1,174	46 %	$ 3,176	58 %

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n/a – not applicable

(a) Equity investment until May 1, 2013. On that date, as part of KMP's Copano acquisition, it acquired the remaining 50% ownership interest that it did not already own. Prior to that date, KMP recorded earnings under the equity method of accounting, but it 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) Primarily represents EBDA from NGPL HoldCo and the following EP assets and investments: Ruby Pipeline Holding Company, L.L.C. and Young Gas Storage Company, LTD.

(c) Represents amounts attributable to KMP's FTC Natural Gas Pipelines disposal group.

The significant increases and decreases in the Natural Gas Pipelines business segment's EBDA in the comparable years of 2013 and 2012 included the following:

- incremental earnings of $1,064 million associated with full-year contributions from assets acquired from EP, including earnings from EPB, TGP, EPNG, EP midstream asset operations, Citrus and Gulf LNG Holdings Group, LLC;
- incremental earnings of $233 million from the Copano operations, which KMP acquired effective May 1, 2013 (but excluding Copano's 50% ownership interest in Eagle Ford, which is included below with the 50% ownership interest it previously owned);
- incremental earnings of $56 million (166%) from KMP's now wholly-owned Eagle Ford natural gas gathering operations, due primarily to the incremental 50% ownership interest it acquired as part of our acquisition of Copano effective May 1, 2013, and partly to higher natural gas gathering volumes from the Eagle Ford shale formation;

- a $16 million (5%) increase from our Texas intrastate natural gas pipeline group, due largely to higher transport margins (primarily related to higher transportation volumes from the Eagle Ford shale formation in south Texas) and lower pipeline maintenance expenses (due to both higher pipeline integrity maintenance and unexpected well repair expenses incurred in the last half of 2012), but partially offset by both lower storage margins (due mainly to timing differences on storage settlements) and lower natural gas processing margins (due mainly to lower NGL prices). The growth in revenues across both comparable years reflect higher natural gas sales revenues, driven by higher natural gas sales volumes in 2013 versus 2012. However, because the intrastate group both purchases and sells significant volumes of natural gas, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases in its natural gas sales revenues were largely offset by corresponding increases in its natural gas purchase costs;
- incremental earnings of $13 million (8%) increase from KinderHawk Field Services, driven by increased CO_2 treating fees, increased gathering rates and increased minimum volume commitments, partly offset by lower throughput volumes; and
- a $26 million (32%) decrease from KMP's natural gas treating operations, primarily due to lower sales volumes and margins from treating equipment manufacturing.

The period-to-period decreases in EBDA from discontinued operations was due to the sale of our FTC Natural Gas Pipelines disposal group effective November 1, 2012. For further information about this sale, see Note 3 "Acquisitions and Divestitures—Divestitures—KMP's FTC Natural Gas Pipelines Disposal Group—Discontinued Operations" to our consolidated financial statements.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
EP assets(a)	$ 96	n/a	$ 18	n/a
EPB	731	n/a	907	n/a
EPNG	222	n/a	301	n/a
EP midstream asset operations	39	n/a	91	n/a
TGP	436	n/a	602	n/a
KinderHawk Field Services(b)	58	52 %	95	96 %
Kinder Morgan Treating operations	33	70 %	69	79 %
Fayetteville Express Pipeline LLC(b)	31	131 %	—	n/a
Eagle Ford(b)	23	203 %	—	n/a
Texas Intrastate Natural Gas Pipeline Group	(6)	(2)%	(776)	(22)%
NGPL Holdco LLC(b)	(17)	(89)%	n/a	n/a
All others (including eliminations)	(1)	(1)%	(20)	(13)%
Total Natural Gas Pipelines - continuing operations	1,645	225 %	1,287	33 %
Discontinued operations(c)	(71)	(30)%	(95)	(29)%
Total Natural Gas Pipelines - including discontinued operations	$ 1,574	162 %	$ 1,192	28 %

n/a – not applicable

(a) Primarily represents EBDA and revenues from the following EP assets and investments: Citrus, Gulf LNG Holdings Group, LLC, Ruby Pipeline Holding Company, L.L.C., Bear Creek Storage and Young Gas Storage Company, LTD.

(b) For these equity investment we record earnings under the equity method of accounting, but we receive distributions in amounts essentially equal to equity earnings plus our share of depreciation and amortization expenses less our share of sustaining capital expenditures.

(c) Represents amounts attributable to KMP's FTC Natural Gas Pipelines disposal group.

The significant increases and decreases in the Natural Gas Pipelines business segment's EBDA in the comparable years of 2012 and 2011 included the following:

- incremental earnings of $1,524 million from assets acquired on May 25, 2012 from EP, including earnings from EPB, EPNG and TGP;
- incremental earnings of $58 million from KMP's wholly-owned KinderHawk Field Services, LLC, due principally to the inclusion of a full year of operations in 2012 (KMP acquired the remaining 50% ownership interest in KinderHawk that it did not already own and began accounting for the investment under the full consolidation method effective July 1, 2011);
- incremental earnings of $33 million due principally to the inclusion of a full year of operations in 2012 from SouthTex Treaters, Inc., which was acquired by Kinder Morgan Treating operations effective November 30, 2011;
- a $31 million (131%) increase in equity earnings from KMP's 50% owned Fayetteville Express Pipeline LLC—driven by a ramp-up in firm contract transportation volumes, and to lower interest expense. Higher year-over-year transportation revenues reflected a 15% increase in natural gas transmission volumes, and the decrease in interest expense related to Fayetteville Express Pipeline LLC's refinancing of its prior bank credit facility in July 2011;
- incremental equity earnings of $23 million from KMP's 50%-owned Eagle Ford, which initiated flow on its natural gas gathering system on August 1, 2011; and
- a $6 million (2%) decrease from the Texas intrastate natural gas pipeline group—driven by higher operating and maintenance expenses, lower margins on natural gas processing activities, and lower margins on natural gas sales. The increase in expenses was driven by both higher pipeline integrity maintenance and unexpected repairs at the Markham storage facility. The decrease in processing margin was mostly due to lower NGL prices, and the year-over-year decrease in sales margin was due to lower average natural gas sales prices in 2012 compared to 2011.

The overall year-to-year decrease in EBDA from discontinued operations was largely due to the loss of income due to the sale of our discontinued operations effective November 1, 2012. EBDA from the Kinder Morgan Interstate Gas Transmission pipeline system, the Trailblazer pipeline system and KMP's investment in the Rockies Express pipeline system decreased $29 million (33%), $20 million (59%) and $17 million (19%) respectively, in 2012 versus 2011. In addition to the loss of income due to our divestiture, earnings from both pipeline systems decreased during the ten months we owned the assets in 2012 compared to the same period in 2011. The decrease was driven by lower revenues in 2012, generally related to lower net fuel recoveries, lower margins on operational natural gas sales, and excess natural gas transportation capacity existing out of the Rocky Mountain region, relative to 2011.

CO_2—KMP

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except operating statistics)		
Revenues(a)	$ 1,857	$ 1,677	$ 1,434
Operating expenses	(439)	(381)	(342)
Other income	—	7	—
Earnings from equity investments	24	25	24
Interest income and Other, net	—	(1)	5
Income tax expense	(7)	(5)	(4)
EBDA(b)	$ 1,435	$ 1,322	$ 1,117
Southwest Colorado CO_2 production (gross) (Bcf/d)(c)	1.2	1.2	1.3
Southwest Colorado CO_2 production (net) (Bcf/d)(c)	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	30.7	29.0	28.6
SACROC oil production (net)(MBbl/d)(e)	25.5	24.1	23.8
Yates oil production (gross)(MBbl/d)(d)	20.4	20.8	21.7
Yates oil production (net)(MBbl/d)(e)	9.0	9.3	9.6
Katz oil production (gross)(MBbl/d)(d)	2.7	1.7	0.5
Katz oil production (net)(MBbl/d)(e)	2.2	1.4	0.4
Goldsmith Landreth oil production (gross)(MBbl/d)(d)	0.7	—	—
Goldsmith Landreth oil production (net)(MBbl/d)(e)	0.6	—	—
NGL sales volumes (net)(MBbl/d)(e)	9.9	9.5	8.5
Realized weighted-average oil price per Bbl(f)	$ 92.70	$ 87.72	$ 69.73
Realized weighted-average NGL price per Bbl(g)	$ 46.43	$ 50.95	$ 65.61

(a) 2013, 2012 and 2011 amounts include unrealized gains of $3 million, unrealized losses of $11 million and unrealized gains of $5 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales. Also, 2011 amount includes an increase in segment earnings resulting from a valuation adjustment of $18 million related to derivative contracts in place at the time of the Going Private Transaction and recorded in the application of the purchase method of accounting.

(b) 2013, 2012 and 2011 amounts include certain items of a $3 million increase in earnings discussed in footnote (a) above, a $4 million decrease in earnings, (net of $11 million of loss discussed in footnote (a) above and $7 million gain from the sale of KMP's ownership interest in the Claytonville oil field unit) and $23 million increase in earnings discussed in footnote (a) above, respectively.

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

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

(e) Net to KMP, after royalties and outside working interests.

(f) Includes all of KMP's crude oil production properties.

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

The CO_2—KMP segment's primary businesses involve the production, marketing and transportation of both CO_2 and crude oil, and the production and marketing of natural gas and NGL. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and Sales and Transportation Activities.

Combined, the certain items described in footnotes (a) and (b) to the table above accounted for a $7 million increase in segment EBDA in 2013, and a $27 million decrease in segment EBDA in 2012, when compared to the respective prior year. The certain items also accounted for a $14 million increase in segment revenues in 2013, and a $34 million decrease in segment revenues in 2012, when compared to the respective prior year. For each of the segment's two primary businesses, following is information related to the remaining (i) $106 million (8%) and $232 million (21%) increases in EBDA; and (ii) $166 million (10%) and $277 million (20%) increases in revenues in both 2013 and 2012, when compared with the respective prior year:

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 74	8%	$ 144	11 %
Sales and Transportation Activities	32	9%	40	10 %
Intrasegment Eliminations	—	—	(18)	(23)%
Total CO_2—KMP	$ 106	8%	$ 166	10 %

The segment's oil and gas producing activities include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants. When compared to 2012, the increase in earnings from the segment's oil and gas producing activities in 2013 was mainly due to the following:

- a $148 million (13%) increase in crude oil sales revenues—due primarily to higher average realized sales prices for U.S. crude oil and partly due to higher oil sales volumes. KMP's realized weighted average price per barrel of crude oil increased 6% in 2013 versus 2012. The overall increase in oil sales revenues were also favorably impacted by a 7% increase in crude oil sales volumes, due primarily to both higher production from the Katz and SACROC field units, and to incremental production from the Goldsmith Landreth unit, which KMP acquired effective June 1, 2013 (volumes presented in the results of operations table above);

- a $9 million (5%) decrease in natural gas plant products sales—due to a 9% decrease in KMP's realized weighted average price per barrel of NGL, but partially offset by a 4% increase in sales volumes; and

- a $65 million (20%) increase in operating expenses—driven primarily by higher fuel and power expenses, and higher maintenance and well workover expenses, all related to both increased drilling activity in 2013 and incremental expenses associated with the Goldsmith Landreth field unit.

EBDA from the segment's sales and transportation activities increased by $32 million (9%) in 2013 versus 2012. The year-to-year increase in earnings was driven by (i) higher CO_2 sales revenues, due to an almost 10% increase in average sales prices; (ii) higher reimbursable project revenues, largely related to the completion of prior expansion projects on the Central Basin pipeline system; and (iii) higher third party storage revenues at the Yates field unit.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 180	23%	$ 228	20%
Sales and Transportation Activities	52	17%	46	13%
Intrasegment Eliminations	—	—%	3	5%
Total CO_2—KMP	$ 232	21%	$ 277	20%

When compared to 2011, the increase in earnings from the segment's oil and gas producing activities in 2012 was mainly due to the following:

- a $256 million (29%) increase due to higher crude oil sales revenues—driven by higher average realizations for U.S. crude oil, and increased oil production at both the Katz and SACROC field units. When compared to 2011, KMP's realized weighted average price per barrel of crude oil increased 26% in 2012 (from $69.73 per barrel in 2011 to $87.72 per barrel in 2012);

- a $46 million (14%) decrease due to higher combined operating expenses—driven primarily by higher well workover expenses (due to increased drilling activity) and higher severance and property tax expenses; and

- a $26 million (13%) decrease due to lower plant product sales revenues—due to a 22% year-over-year decrease in the realized weighted average price per barrel of NGL (from $65.61 per barrel in 2011 to $50.95 per barrel in 2012). The decrease in revenues from lower prices more than offset an increase in revenues related to an overall 12% increase in plant products sales volumes.

The increase in EBDA from the segment's sales and transportation activities in 2012 compared to 2011 was primarily revenue related, attributable to the following:

- a $24 million (10%) increase due to higher CO2 sales revenues—driven by a 17% increase in average sales prices, due primarily to two factors: (i) a change in the mix of contracts resulting in more CO2 being delivered under higher price contracts and (ii) heavier weighting of new CO2 contract prices to the price of crude oil; and

- a $22 million (22%) increase in all other revenues—due largely to both higher non-consent revenues and higher reimbursable project revenues. The increase in non-consent revenues related to sharing arrangements pertaining to certain expansion projects completed at the McElmo Dome unit in Colorado since the end of 2011. The increase in reimbursable revenues related to the completion of prior expansion projects on the Central Basin pipeline system.

Products Pipelines—KMP

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except operating statistics)		
Revenues	$ 1,853	$ 1,370	$ 914
Operating expenses	(1,295)	(759)	(500)
Other income (expense)	(6)	5	8
Earnings from equity investments	45	39	34
Interest income and Other, net	3	11	8
Income tax benefit (expense)	2	2	(3)
EBDA(a)	$ 602	$ 668	$ 461
Gasoline (MMBbl) (b)	423.4	395.3	398.0
Diesel fuel (MMBbl)	142.4	141.5	148.9
Jet fuel (MMBbl)	110.6	110.6	110.5
Total refined product volumes (MMBbl)(c)	676.4	647.4	657.4
NGL (MMBbl)(d)	37.3	31.7	26.1
Condensate (MMBbl)(e)	12.6	1.4	n/a
Total delivery volumes (MMBbl)	726.3	680.5	683.5
Ethanol (MMBbl)(f)	38.7	33.1	30.4

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(a) 2013, 2012 and 2011 amounts include decreases in earnings of $182 million, $35 million and $233 million, respectively, related to the combined effect from certain items. 2013 amount consists of a $162 million increase in expense associated with rate case liability adjustments, a $15 million increase in expense associated with a legal liability adjustment related to a certain West Coast terminal environmental matter and a $5 million loss from the write-off of assets at KMP's Los Angeles Harbor West Coast terminal. 2012 amount consists of a $32 million increase in expense associated with environmental liability and environmental recoverable receivable adjustments, and a combined $1 million decrease in earnings from other certain items. 2011 amount consists of a $168 million increase in expense associated with rate case liability adjustments, a $60 million increase in expense associated with rights-of-way lease payment liability adjustments, and a combined $3 million decrease in earnings from other certain items. Also, 2012 and 2011 amounts include decreases in earnings of $2 million and $2 million, respectively, related to property disposal losses, which had been revalued as part of the Going Private Transaction and recorded in the application of the purchase method of accounting.

(b) Volumes include ethanol pipeline volumes.

(c) Includes Pacific, Plantation Pipe Line Company, Calnev, Central Florida and Parkway pipeline volumes.

(d) Includes Cochin and Cypress pipeline volumes.

(e) Includes Kinder Morgan Crude & Condensate and Double Eagle Pipeline LLC pipeline volumes.

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

Combined, the certain items described in footnote (a) to the table above accounted for a $147 million decrease in segment EBDA in 2013, and a $198 million increase in segment EBDA in 2012, when compared with the respective prior year. Following is information related to the segment's (i) remaining $81 million (12%) and $9 million (1%) increases in EBDA and (ii) $483 million (35%) and $456 million (50%) increases in revenues in both 2013 and 2012, when compared with the respective prior year:

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Transmix operations	$ 27	174 %	$ 406	82%
Cochin Pipeline	25	34 %	33	42%
Kinder Morgan Crude & Condensate Pipeline	14	n/a	19	n/a
Southeast terminal operations	6	9 %	12	12%
Plantation Pipe Line Company	4	6 %	—	n/a
Double Eagle Pipeline LLC	3	n/a	3	n/a
Pacific operations	(7)	(3)%	3	1%
All others (including eliminations)	9	5 %	7	3%
Total Products Pipelines—KMP	$ 81	12 %	$ 483	35%

n/a - not applicable

The primary increases and decreases in the Products Pipelines—KMP business segment's EBDA in 2013 compared to 2012 were attributable to the following:

- a $27 million (174%) increase from KMP 's transmix processing operations-due to higher margins on processing volumes, incremental earnings from third-party sales of excess renewable identification numbers (RINS) (generated through its ethanol blending operations), and to the recognition of unfavorable net carrying value adjustments to product inventory recognized in 2012. The period-to-period increases in revenues were mainly due to the expiration of certain transmix fee-based processing agreements since the end of the third quarter of 2012. Due to the expiration of these contracts, KMP now directly purchases incremental transmix volumes and sells incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;

- a $25 million (34%) increase from KMP's Cochin Pipeline-primarily due to higher transportation revenues, driven by an overall 33% increase in pipeline throughput volumes, partly attributable to incremental ethane/propane volumes as a result of pipeline modification projects completed in June 2012;

- incremental earnings of $14 million from KMP's Kinder Morgan Crude & Condensate Pipeline, which began transporting crude oil and condensate volumes from the Eagle Ford shale gas formation to multiple terminaling facilities along the Texas Gulf Coast in October 2012;

- a $6 million (9%) increase from KMP's Southeast terminal operations, driven by higher margins from ethanol blending operations, and higher revenues from refined products and bio-fuels throughput volumes;

- a $4 million (6%) increase from KMP's approximate 51% interest in Plantation Pipe Line Company-due largely to higher transportation revenues driven by an 11% increase in system delivery volumes, and by higher average tariff rates since the end of 2012;

- incremental earnings of $3 million from KMP's 50% interest in Double Eagle Pipeline LLC-which gathers condensate and crude oil for Eagle Ford shale producers and which KMP acquired as part of its Copano acquisition effective May 1, 2013;

- a $7 million (3%) decrease from KMP's Pacific operations, primarily attributable to a reduction in mainline transportation revenues with a nearly 2% increase in system-wide delivery volumes. The change to transport revenues related to reductions associated with various interstate and California intrastate rate case decisions; and

- a $9 million (5%) increase from all other represents a number of small increases at various locations.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline	$ 22	43 %	$ 4	5 %
Kinder Morgan Crude & Condensate Pipeline	5	230 %	4	n/a
Plantation Pipe Line Company	4	7 %	1	3 %
Southeast terminal operations	4	5 %	3	3 %
Transmix operations	(18)	(54)%	447	928 %
Pacific operations	(9)	(3)%	(10)	(2)%
Calnev	(8)	(16)%	(6)	(8)%
All others (including eliminations)	9	7 %	13	7 %
Total Products Pipelines—KMP	$ 9	1 %	$ 456	50 %

n/a - not applicable

The primary increases and decreases in the Products Pipelines—KMP business segment's EBDA in 2012 compared to 2011 were attributable to the following:

- a $22 million (43%) increase from the Cochin NGL pipeline system-due mainly to a $10 million increase in gross margin, and due partly to both the favorable settlement of a pipeline access dispute and a favorable 2012 income tax adjustment. The increase in gross margin was mainly due to an overall 40% increase in pipeline throughput volumes, which included incremental ethane/propane volumes related primarily to completed expansion projects since the end of 2011;

- incremental earnings of $5 million from the Kinder Morgan Crude & Condensate Pipeline, which began transporting crude oil and condensate volumes in October 2012;

- a $4 million (7%) increase from KMP's approximate 51% equity interest in Plantation Pipe Line Company-due largely to higher transportation revenues driven by higher average tariff rates since the end of 2011;

- a $4 million (5%) increase from the Southeast terminal operations—due mainly to higher butane blending revenues and increased throughput volumes of refined products and biofuels;

- an $18 million (54%) decrease from the transmix processing operations—due primarily to a decrease in processing volumes and unfavorable net carrying value adjustments to product inventory. The year-to-year increases in revenues was due mainly to the expiration of certain transmix fee-based processing agreements in March 2012. Due to the expiration of these contracts, KMP now directly purchases incremental volumes of transmix and sells incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;

- a $9 million (3%) decrease from the Pacific operations—primarily attributable to a corresponding $9 million drop in mainline transportation revenues, due primarily to lower average FERC tariffs as a result of rate case rulings settlements made since the end of 2011, and due partly to a 2% decrease in mainline delivery volumes; and

- an $8 million (16%) decrease from Calnev—chiefly due to an approximate 9% decrease in pipeline delivery volumes that were due in part to incremental services offered by a competing pipeline.

Terminals—KMP

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except operating statistics)		
Revenues	$ 1,410	$ 1,359	$ 1,315
Operating expenses	(657)	(685)	(634)
Other income (expense)	74	14	(1)
Earnings from equity investments	22	21	11
Interest income and Other, net	1	2	6
Income tax (expense) benefit	(14)	(3)	5
EBDA(a)	$ 836	$ 708	$ 702
Bulk transload tonnage (MMtons)(b)	89.9	96.9	99.8
Ethanol (MMBbl)	65.0	65.3	61.0
Liquids leaseable capacity (MMBbl)	68.1	60.4	60.2
Liquids utilization %(c)	94.5%	92.8%	94.5%

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(a) 2013, 2012 and 2011 amounts include an increase of $38 million, a decrease of $44 million, and an increase of $1 million, respectively, related to the combined effect from certain items. 2013 amount consists of (i) a $109 million increase in earnings from casualty indemnification gains; (ii) an $8 million increase in revenues related to hurricane reimbursements; (iii) 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 (iv) a $3 million increase in expense associated with the removal of certain physical assets at the Tampaplex bulk terminal located in Tampa, Florida. 2012 amount consists of a $51 million increase in expense related to hurricanes Sandy and Isaac clean-up and repair activities and the associated write-off of damaged assets, a $4 million increase in expense associated with environmental liability adjustments, and a $12 million casualty indemnification gain related to a 2010 casualty at the Myrtle Grove, Louisiana, International Marine Terminal facility. 2011 amount consists of a $5 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to KMP from us (however, KMP does not have any obligation, nor did it pay any amounts or realize any direct benefits related to this compensation expense) and a combined $2 million decrease from other certain items. Also, 2013, 2012 and 2011 amounts include decreases of earnings of $17 million, $1 million, and $2 million, respectively, related to assets sold, which had been revalued as part of the Going Private Transaction and recorded in the application of the purchase method of accounting.

(b) Volumes for acquired terminals are included for all periods and include KMP's proportionate share of joint venture tonnage.

(c) The ratio of KMP's actual leased capacity to its estimated potential capacity.

The Terminals—KMP business segment includes the operations of petroleum, chemical and other liquids terminal facilities (other than those included in the Products Pipelines—KMP segment), and all of coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. KMP groups its bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows the management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

Combined, the certain items described in footnote (a) to the table above accounted for a $82 million increase in segment EBDA in 2013, a $45 million decrease in segment EBDA in 2012, and an $8 million increase in segment revenues in 2013, when compared with the respective prior year. Following is information related to the segment's (i) remaining $46 million (6%) and $51 million (7%) increases in EBDA and (ii) $43 million (3%) and $44 million (3%) increases in revenues in both 2013 and 2012, when compared with the respective prior year:

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	$ 21	11 %	$ 34	14 %
Rivers	15	24 %	7	5 %
Midwest	9	18 %	14	11 %
Northeast	5	4 %	1	— %
Acquired assets and businesses	4	n/a	5	n/a
Southeast	3	7 %	—	— %
Mid-Atlantic	—	— %	(5)	(3)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(11)	(5)%	(13)	(3)%
Total Terminals—KMP	$ 46	6 %	$ 43	3 %

The overall increase in the Terminals—KMP's EBDA in 2013 versus 2012 was driven by incremental contributions from its Gulf Liquids terminals, due primarily to higher liquids revenues from its 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. For all terminals included in the Terminals—KMP business segment, total liquids leaseable capacity increased to 68.1 MMBbl at year-end 2013, up 12.7% from a capacity of 60.4 MMBbl at the end of 2012. The increase in capacity was mainly due to the acquisition of KMP's Norfolk and Chesapeake, Virginia facilities from Allied Terminals in June 2013 (incremental contributions from these two terminals are included within the "Acquired assets and businesses" line in the two tables above), and the partial in-service of BOSTCO and Edmonton Tank expansion projects. At the same time, KMP's overall liquids utilization rate increased 1.8% since the end of 2012.

The Rivers region earnings and revenues increased due to the in-service of the IMT Phase I and II expansion projects at KMP's International Marine Terminal (located at Myrtle Grove, Louisiana, near the mouth of the Mississippi River). The region also benefited from lower operating and maintenance costs.

Much of the Midwest's improvement comes from the opening in August 2013 of the BP Whiting terminal (Whiting, Indiana). Salt and ethanol increases account for the rest of the improvement.

The period-to-period increases in earnings from KMP's Northeast terminal operations were driven by incremental contributions from KMP's Carteret New Jersey liquids facility and KMP's Perth Amboy, New Jersey liquids terminal. Carteret benefited from both higher non-operating income (due to insurance indemnifications received for 2012 business interruptions caused by Hurricane Sandy) and higher revenues (due in part to new and restructured customer agreements at higher rates). KMP's Perth Amboy terminal benefited from higher year-over-year revenues, due mainly to additional and restructured customer contracts at higher rates.

Earnings from KMP's Mid-Atlantic terminals were flat across both 2013 and 2012, as higher earnings from its Fairless Hills, Pennsylvania bulk terminal were offset by lower earnings and revenues from its Pier IX terminal, located in Newport News, Virginia. The earnings increase from Fairless Hills was primarily due to higher margins and volumes from steel and fertilizer transfers, driven by rebounding manufacturing and agricultural demand in the last half of 2013, as well as fertilizer expansion projects coming on-line. The decreases in revenues and earnings from Pier IX were due primarily to an 8% drop in coal transfer volumes, due largely to some weakening in the coal export market relative to 2012, and due partly to scheduled maintenance at the facility in the second quarter of 2013.

The remaining increases and decreases in the Terminals—KMP segment's earnings and revenues reported in the "All others" line in the table above represent increases and decreases in terminal results at various locations; however the overall decreases across the comparable years were due in large part to (i) the loss of business effective March 31, 2013 when TRANSFLO, a wholly owned subsidiary of CSX, elected to terminate their contract with KMP's materials handling, wholly-owned subsidiary, Kinder Morgan Materials Services (KMMS), and (ii) higher income tax expense.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	$ 19	11 %	$ 17	7 %
Mid-Atlantic	15	25 %	19	16 %
Northeast	15	19 %	18	13 %
Acquired assets and businesses	10	n/a	4	n/a
All others (including intrasegment eliminations and unallocated income tax expenses)	(8)	(2)%	(14)	(2)%
Total Terminals—KMP	$ 51	7 %	$ 44	3 %

The overall increase in EBDA from the Terminals—KMP business segment in 2012 compared to 2011was driven by higher contributions from the terminal facilities included in the Gulf Liquids, Mid-Atlantic and Northeast regions. The increase from the Gulf Liquids facilities was driven by higher warehousing revenues (as a result of new and renewed customer agreements at higher rates) at the Galena Park and Pasadena, Texas facilities, higher ethanol volumes through the Deer Park, Texas rail terminal, and higher overall gasoline throughput volumes. KMP also benefited from both higher capitalized overhead associated with the ongoing construction of KMP's majority-owned Battleground Oil Specialty Terminal Company LLC terminal located on the Houston Ship Channel, and higher earnings from its crude oil storage operations located in Cushing, Oklahoma.

The year-to-year earnings increase from the Mid-Atlantic region resulted primarily from higher export coal shipments from the Pier IX terminal, and higher import steel and iron ore imports from the Fairless Hills, Pennsylvania bulk terminal. Economic expansion in developing countries generated a growth cycle in the coal export market during 2012, and due both to this growth in demand and to completed infrastructure expansions since the end of 2011, KMP's total export coal volumes (for all terminals combined) increased by 5.7 million tons (38%) in 2012, when compared to the prior year.

The increase in earnings from the Northeast terminal operations was driven by higher contributions from the Staten Island terminal due mainly to new and favorable contract changes. Despite being affected heavily by Hurricane Sandy in 2012, the liquids terminal in Carteret, New Jersey increased earnings primarily due to higher transfer and storage rates, and to new and renegotiated contracts. KMP also benefited from incremental earnings from the Philadelphia liquids terminal, due largely to new and restructured customer contracts at higher rates, and from the Perth Amboy, New Jersey liquids terminal, due primarily to higher gasoline throughput volumes and favorable contract changes.

The incremental earnings and revenues from acquired assets and businesses primarily represent contributions from KMP's additional equity investment in the short-line railroad operations of Watco Companies, LLC (acquired in December 2011) and its bulk terminal (acquired in June 2011) that handles petroleum coke for the Total refinery located in Port Arthur, Texas. The incremental amounts represent earnings and revenues from acquired terminals' operations during the additional months of ownership in 2012, and do not include increases or decreases during the same months KMP owned the assets in 2011.

The remaining increases and decreases in the Terminals—KMP segment's earnings and revenues—reported in the "All others" line in the table above —represent increases and decreases in terminal results at various locations; however the overall decreases were driven by lower results from the combined terminal operations included in the Rivers region. The decreases were mainly due to lower domestic coal transload volumes, largely the result of a drop in domestic demand relative to 2011.

Kinder Morgan Canada—KMP

	Year Ended December 31,		
	2013	2012	2011
	(In millions, except operating statistics)		
Revenues	$ 302	$ 311	$ 302
Operating expenses	(110)	(103)	(97)
Earnings from equity investments	4	5	(2)
Interest income and Other, net	249	17	14
Income tax expense	(105)	(1)	(15)
EBDA(a)	$ 340	$ 229	$ 202
Transport volumes (MMBbl)(b)	101.1	106.1	99.9

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(a) 2013 amount includes both a $224 million gain from the sale of KMP's equity and debt investments in the Express pipeline system, and an associated $84 million increase in income tax expense related to the pre-tax gain amount. 2011 amount includes a $3 million increase in earnings associated with an income tax benefit (reflecting tax savings) related to non-cash compensation expense allocated to KMP from us (however, KMP does not have any obligation, nor did it pay any amounts related to this compensation expense).

(b) Represents Trans Mountain pipeline system volumes.

The Kinder Morgan Canada—KMP business segment includes the operations of the Trans Mountain and Jet Fuel pipeline systems and until March 14, 2013, the effective date of sale, KMP's one-third ownership interest in the Express crude oil pipeline system. Combined, the certain items described in footnote (a) to the table above accounted for a $140 million increase in segment EBDA in 2013, and a $3 million decrease in segment EBDA in 2012, when compared with the respective prior year.

Following is information related to the segment's (i) remaining $29 million (13%) decrease and $30 million (15%) increase in EBDA in 2013 and 2012 and (ii) $9 million (3%) decrease and $9 million (3%) increase in revenues in 2013 and 2012, when compared with the respective prior year:

Year Ended December 31, 2013 versus Year Ended December 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ (24)	(11)%	$ (9)	(3)%
Express Pipeline(a)	(5)	(28)%	n/a	n/a
Total Kinder Morgan Canada—KMP	$ (29)	(13)%	$ (9)	(3)%

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(a) Equity investment; accordingly, KMP recorded earnings under the equity method of accounting. However, KMP sold its debt and equity investments in Express effective March 14, 2013.

The period-to-period decreases in EBDA from Express were primarily due to both lower equity earnings and lower interest income resulting from the sale of KMP's equity and debt investments in Express effective March 14, 2013.

The decreases in Trans Mountain's earnings were driven by (i) higher income tax expenses (due largely to general increases in British Columbia's income tax rates since the end of the third quarter of 2012); (ii) unfavorable impacts from foreign currency translation (due to the weakening of the Canadian dollar since the end of 2012, KMP translated Canadian denominated income and expense amounts into less U.S. dollars in 2013); and (iii) lower management incentive fees earned from the operation of the Express pipeline system (due to its sale in March 2013). The period-to-period decreases in Trans Mountain's earnings were partially offset by incremental non-operating income from allowances for funds used during construction (representing an estimate of the cost of capital funded by equity contributions).

Year Ended December 31, 2012 versus Year Ended December 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 23	12%	$ 9	3%
Express Pipeline	7	61%	—	—%
Total Kinder Morgan Canada—KMP	$ 30	15%	$ 9	3%

The year-to-year increase in Trans Mountain's EBDA was driven by a $17 million decrease in income tax expenses, associated primarily with favorable tax adjustments, recorded in 2012, related to lower taxable income relative to 2011. Trans Mountain also benefited from higher non-operating income, related primarily to incremental management incentive fees earned from its operation of the Express pipeline system. The year-over-year increase in earnings from the equity investment in the Express pipeline system was mainly due to volumes moving at higher transportation rates on the Express (Canadian) portion of the system, and to higher domestic volumes on the Platte (domestic) portion of the segment.

Other

Our other segment activities include those operations that were acquired from EP on May 25, 2012 and are primarily related to several physical natural gas contracts with power plants associated with EP's legacy trading activities. These contracts obligate EP to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028. This segment also included an interest in the Bolivia to Brazil Pipeline, which we sold for $88 million on January 18, 2013. This segment contributed a loss of $5 million and earnings of $7 million for the years ended 2013 and 2012.

General and Administrative, Interest, and Noncontrolling Interests

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
KMI general and administrative expense(a)(b)	$ (30)	$ 297	$ 42
KMP general and administrative expense(c)	560	547	473
EPB general and administrative expense(d)	83	85	—
Consolidated general and administrative expense	$ 613	$ 929	$ 515
KMI interest expense, net of unallocable interest income(e)	$ 528	$ 559	$ 170
KMP interest expense, net of unallocable interest income(f)	860	700	531
EPB interest expense, net of unallocable interest income(g)	300	182	—
Unallocable interest expense net of interest income and other, net	$ 1,688	$ 1,441	$ 701
KMR noncontrolling interests	$ 230	$ (15)	$ 14
KMP noncontrolling interests(h)	1,018	(51)	52
EPB noncontrolling interests	251	178	—
Net income attributable to noncontrolling interests	$ 1,499	$ 112	$ 66

(a) 2013 includes a decrease in expense of $80 million, 2012 includes an increase in expense of $251 million, and 2011 includes a decrease in expense of $2 million, related to the combined effect from certain items. 2013 amount includes a decrease in expense of (i) $59 million related to EP post-merger pension credits; (ii) $32 million elimination of intercompany rent expense included in KMP and EPB general and administrative expenses; (iii) $5 million for an overaccrual related to The Oil Insurance Limited exit premium; (iv) $3 million related to grantor trust credit; and (v) $2 million payroll tax overaccrual; partially offset by increases in expense of (i) $14 million related to rent expense and lease exit cost on unoccupied space and (ii) $7 million related to the EP acquisition. 2012 amount includes $251 million increase of pre-tax expense associated with the EP acquisition and EP Energy sale, which includes (i) $59 million (also see footnotes (c) and (d) below for KMP and EPB portion, respectively) in employee severance, retention and bonus costs; (ii) $87 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory fees; (iv) $68 million for legal fees and reserves, net of recoveries; and (v) $29 million of other EP acquisitions expenses; partially offset by (i) $29 million benefit associated with pension income. 2011 amount includes a net $2 million decrease in expense, which includes (i) $46 million reduction to expense for a Going Private transaction litigation insurance reimbursement; net of increases in expense for (ii) KMI's portion ($13 million) of a $100 million special bonus to non-senior management employees; (iii) $11 million of expense associated with our initial public offering; (iv) a $9 million increase in expense related to the EP acquisition; and (v) $10 million increase in Going Private transaction litigation expense; and (vi) a combined $1 million increase in other expense related primarily to non-cash compensation expense. The cost of the $100 million special bonus was not borne by our Class P shareholders. In May of 2011, we paid for the $100 million of special bonuses, which included the amounts allocated to KMP, using $64 million (after-tax) in available earnings and profits reserved for this purpose and not paid in dividends to our Class A shareholders. See also footnote (c) below.

(b) 2013, 2012 and 2011 amounts include NGPL Holdco LLC general and administrative reimbursements of $36 million, $35 million, and $35 million, respectively. These amounts were recorded to the "Product sales and other" caption in our accompanying consolidated statements of income with the offsetting expenses primarily included in the "General and administrative" expense caption in our accompanying consolidated statements of income.

(c) 2013, 2012 and 2011 amounts include increases in expense of $40 million, $81 million and $94 million, respectively, related to the combined effect from certain items. 2013 amount consists of (i) a $34 million increase in expense associated with certain asset and business acquisition costs and unallocated legal expenses; (ii) a $10 million increase in unallocated severance expense associated with the asset drop-down groups and allocated to KMP from us (however, KMP does not have any obligation, nor did it pay any amounts related to this expense); and (iii) a combined $4 million decrease in expense from other certain items. 2012 amount consists of $67 million in severance, retention and bonus costs and a combined $14 million increase in expense from other certain items. 2011 amount consists of a combined $90 million increase in non-cash compensation expense (including $87 million related to a special non-cash bonus expense to non-senior management employees) allocated to KMP from us; however, it does not have any obligation, nor did it pay any amounts related to this expense, and a combined $4 million increase in expense from other certain items.

(d) 2012 amount includes $34 million for severance cost. This expense is attributable to non-cash severance costs allocated to EPB from us as a result of KMI's and EP's merger; however, EPB does not have any obligation, nor did EPB pay any amounts related to this expense.

(e) 2013 and 2012 amounts include $21 million and $108 million, respectively, write off of capitalized financing fees, almost all of which was associated with the EP acquisition financing that was written-off (primarily due to debt repayment) or amortized. 2013 amount also includes $14 million of interest on margin for marketing contracts.

(f) 2013 includes a decrease in expense of $5 million associated with debt fair value adjustments recorded in purchase accounting for KMP's Copano acquisition. 2012 amount includes a decrease in expense of $1 million related to the combined effect from other certain items.

(g) Includes expenses and transactions for the periods after the May 25, 2012 EP acquisition date.

(h) 2013, 2012 and 2011 amounts include an increase of $5 million, a decrease of $4 million and a decrease of $7 million, respectively, in net income attributable to KMP's noncontrolling interests, related to the combined effect from all of the 2013, 2012 and 2011 items previously disclosed in the footnotes to the tables included in "-Results of Operations."

Combined, the certain items described in footnotes (a) and (b) to the table above affected KMI's general and administrative expenses by a $330 million decrease in 2013 and $253 million increase in 2012, when compared with the respective year. The remaining changes in KMI's general and administrative expense was essentially flat in both 2013 and 2012, when compared with the respective year.

2013 and 2012 amounts also include $9 million and $43 million, respectively, of KMP expense attributable to KMP's drop-down asset groups for the periods prior to the acquisition dates. Combined, the certain items described in footnote (c) to the table above, and the combined $34 million decrease in expense from the drop-down asset groups expense prior to the acquisition dates, decreased KMP's general and administrative expenses by $75 million in 2013, and increased its general and administrative expenses by $30 million in 2012, when compared with the respective prior year. The remaining $88 million (21%) and $44 million (12%) increases in general and administrative expenses in 2013 and 2012, respectively, were driven by the acquisition of additional businesses, primarily associated with KMP's acquisition of the drop-down asset groups from us (effective August 1, 2012 and March 1, 2013), and for 2013 versus 2012, its acquisition of Copano (effective May 1, 2013). KMP also realized higher year-over-year employee benefits and payroll tax expenses, due mainly to both cost inflation increases on work-based health and insurance benefits and higher wage rates.

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. Combined, the certain items described in footnotes (e) and (f) to the table above affected our consolidated interest expense by a $77 million decrease in 2013 and a $107 million increase in 2012, when compared with the respective prior year. Our remaining consolidated interest expense, net of interest income, increased $324 million (24%) and $633 million (90%), respectively, in 2013 and 2012 when compared with the respective prior year.

The increase in KMI's interest expense in 2013 and 2012 compared to respective prior years was primarily due to interest expense incurred from (i) EP acquisition debt and (ii) debt assumed in the EP acquisition, see Notes 3 "Acquisition and Divestitures—KMI Acquisition of El Paso Corporation" and Note 8 "Debt" to our consolidated financial statements.

For KMP, the 2013 and 2012 amounts also include $15 million and $69 million, respectively, of KMP expense attributable to KMP's drop-down asset groups for the periods prior to the acquisition dates. After taking into effect the certain items described in footnote (f) to the table above, and the combined $54 million decrease in expense from the drop-down asset groups expense prior to the acquisition dates, KMP's unallocable interest expense increased $218 million (34%) in 2013 compared to 2012, and increased $101 million (19%) in 2012 compared to 2011. For both pairs of comparable years, the increase in interest expense was attributable to higher average borrowings, and for 2013 compared to 2012, to higher effective interest rates. KMP's average debt balances increased 24% in 2013 and 23% in 2012, when compared to the respective prior year. The increases in average borrowings were largely due to the capital expenditures, business acquisitions (including debt assumed from the drop-down transactions), and joint venture contributions KMP has made since the beginning of 2011. For more information on the capital expenditures, capital contributions, and acquisition expenditures, see "—Liquidity and Capital Resources."

The weighted average interest rate on all of KMP's borrowings—including both short-term and long-term amounts—increased by 9% in 2013 versus 2012, but was essentially flat across both 2012 and 2011 (the weighted average interest rate on all of KMP's borrowings was 4.62% during 2013, 4.24% during 2012 and 4.26% during 2011). The higher average rate in 2013 was driven primarily by higher interest rates on the debt obligations KMP assumed as part of the drop-down transactions.

We, and our subsidiary KMP, 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, 2013, approximately 27% of KMI's and 29% of KMP's 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. EPB did not have variable rate debt obligations as of December 31, 2013. As of December 31, 2012, approximately 47% of KMI's and 37% of KMP's debt balances (excluding debt fair value adjustments) were subject to variable interest rates. For more information on our interest rate swaps, see Note 13 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements.

Net income attributable to noncontrolling interests, which represents the allocation of our consolidated net income (or loss) attributable to all outstanding ownership interests in our consolidated subsidiaries (primarily KMP and EPB) that are not held by us. The $1,387 million (1,238%) increase for 2013 as compared to 2012 was primarily due to our noncontrolling interest's portion of (i) KMP's $558 million gain from the remeasurement of its previously held 50% equity interest in Eagle Ford to fair value; (ii) KMP's $140 million after-tax gain on the sale of its investments in the Express pipeline system; (iii) KMP's additional income from EP assets acquired by KMP from us; (iv) KMP's additional income from its acquisition of Copano; and (v) the 2012 non-cash loss of $937 million net of tax loss from both costs to sell and the remeasurement of KMP's FTC Natural Gas Pipeline disposal group net assets to fair value. The $46 million (70%) increase in 2012 as compared to 2011 was primarily due to our noncontrolling interests portion of the additional income from acquisitions and partially offset by non-cash loss of $937 million from both the costs to sell and a remeasurement of the FTC Natural Gas Pipeline disposal group net assets to fair value.

Income Taxes—Continuing Operations

Year Ended December 31, 2013 versus Year Ended December 31, 2012

Our tax expense for income from continuing operations for the year ended December 31, 2013 was $742 million, as compared with 2012 income tax expense of $139 million. The $603 million increase in tax expense is due primarily to (i) higher income in 2013 attributable to KMI's investments in KMP and EPB as compared to 2012 and (ii) tax expense as a result of KMP's 2013 sale of its one-third interest in the Express pipeline system. These increases are partially offset by a decrease in the deferred state tax rate as a result of the March 2013 drop-down transaction and KMP's Copano acquisition.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

Our income tax expense for income from continuing operations for the year ended December 31, 2012 was $139 million, as compared with 2011 income tax expense of $361 million. The $222 million decrease in tax expense is due primarily to (i) lower income attributable to KMI as a result of costs incurred in 2012 to facilitate the EP acquisition and a $200 million impairment of our NGPL investment and (ii) a 2012 adjustment to decrease our income tax reserve for uncertain tax positions. These decreases are partially offset by (i) a 2012 adjustment to increase the deferred tax liability for a change in non tax-deductible goodwill related to our investment in KMP and (ii) the tax impact of an increase in the deferred state tax rate in 2012 as a result of the EP acquisition.

Liquidity and Capital Resources

General

As of December 31, 2013, we had a combined $598 million of "Cash and cash equivalents," a decrease of $116 million (16%) from December 31, 2012. We believe that our cash position and remaining borrowing capacity (discussed below in "—Short-term Liquidity"), and our access to financial resources are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations.

We have relied primarily on cash provided from operations to fund our operations as well as our debt interest payments, sustaining capital expenditures (those capital expenditures which do not increase the capacity or throughput), quarterly dividend payments and our subsidiaries' quarterly distributions.

Expansion capital expenditures, acquisitions and debt principal payments, as such debt principal payments become due, have historically been funded by us and our subsidiaries through (i) additional borrowings (including commercial paper issuances by KMP); (ii) the issuance of additional common stock by us; (iii) issuance of shares by KMR with proceeds used for its purchase of additional KMP i-units; (iv) issuance of common units by KMP or EPB; and (v) and in some instances, proceeds from divestitures.

In addition, KMP has funded a portion of its historical expansion capital expenditures with retained cash, from including i-units owned by KMR in the determination of KMP's cash distributions per unit, but paying quarterly distributions on i-units in additional i-units rather than cash and from waived incentive distributions to KMGP, KMP's general partner. Additional information regarding KMP's distributions and waived incentive distributions is discussed in Note 10 "Stockholders' Equity—Noncontrolling Interests—Distributions—KMP Distributions."

In addition to results of operations, our, KMP and EPB's debt and capital balances are affected by financing activities, as discussed below in "—Financing Activities."

Credit Ratings and Capital Market Liquidity

Our and our subsidiaries' credit ratings affect our ability to access the public and private debt markets (including the commercial paper market by KMP), as well as the terms and pricing of our debt (see Part I, Item 1A "Risk Factors"). Based on our and our subsidiaries' credit ratings as discussed below, we and our subsidiaries expect that our respective short-term liquidity needs will be met primarily through short-term borrowings. Nevertheless, our and our subsidiaries' ability to satisfy financing requirements or fund planned capital expenditures (including our share of planned expenditures of our joint ventures) will depend upon future operating performance, which will be affected by prevailing economic conditions in the energy pipeline and terminals industries and other financial and business factors, some of which are beyond our control. KMP's short-term corporate debt rating is A-2, Prime-2 and F2 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI, KMP and EPB's debt ratings as of December 31, 2013.

	Rating agency	Senior debt rating	Date of last change	Outlook
KMI(a)	Standard and Poor's	BB	February 20, 2008	Positive
	Moody's Investor Services	Ba2	February 27, 2013	Stable
	Fitch Ratings, Inc.	BB+	August 9, 2012	Stable
KMP(b)	Standard and Poor's	BBB	January 8, 2007	Stable
	Moody's Investor Services	Baa2	May 30, 2007	Stable
	Fitch Ratings, Inc.	BBB	April 11, 2007	Stable
EPB(b)	Standard and Poor's	BBB-	May 24, 2012	Positive
	Moody's Investor Services	Ba1	March 25, 2010	Positive
	Fitch Ratings, Inc.	BBB-	March 25, 2010	Stable

(a) Represents senior secured credit rating
(b) Represents senior unsecured credit rating

Short-term Liquidity

As of December 31, 2013, our principal sources of short-term liquidity are (i) KMI, KMP and EPB's respective credit facilities (discussed following); (ii) KMP's $2.7 billion short-term commercial paper program; and (iii) cash from operations. The loan commitments under the facilities can be used to fund borrowings for the respective entity's general corporate or partnership purposes, and KMP's facility can be used as a backup for its commercial paper program. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity related to our credit facilities and have consistently generated strong cash flow from operations, providing a source of funds of $4,064 million and $2,795 million in 2013 and 2012, respectively (the year-to-year increase is discussed below in "Cash Flows—Operating Activities").

The following represents our primary revolving credit facilities that were available to KMI and its subsidiaries, KMP and EPB, debt outstanding under the credit facilities, including commercial paper borrowings, and available borrowing capacity under the facilities after deducting (i) outstanding letters of credit and (ii) outstanding borrowings under KMI and EPB's credit facilities, and KMP's commercial paper program (supported by its credit facility).

	At December 31, 2013	
	Debt outstanding	Available borrowing capacity
	(In millions)	
Credit Facilities		
KMI		
$1.75 billion, six-year secured revolver, due December 2014	$ 175	$ 1,495
KMP		
$2.7 billion, five-year unsecured revolver, due May 2018	$ 979	$ 1,518
EPB		
$1.0 billion, five-year secured revolver, due May 2016	$ —	$ 1,000

Our combined balance of short-term debt as of December 31, 2013 was $2,306 million, primarily consisting of (i) $1,154 million combined outstanding borrowings under KMI's $1.75 billion credit facility and KMP's $2.7 billion commercial paper program; (ii) $500 million in principal amount of KMP's 5.125% senior notes that mature November 15, 2014; (iii) a combined $193 million of borrowings outstanding under EP credit facilities; and (iv) $207 million in principal amount of EP's 6.875% senior notes that mature on June 15, 2014. KMP intends to refinance its current short-term debt through a combination of long-term debt, equity, and/or the issuance of additional commercial paper or credit facility borrowings to replace maturing commercial paper and current maturities of long-term debt. KMI intends to refinance its short-term debt through additional credit facility borrowings to replace maturing credit facility borrowings, issuing new long-term debt, or with proceeds from asset sales. Our combined balance of short-term debt as of December 31, 2012 was $2,401 million.

We had working capital deficits of $2,207 million and $1,554 million as of December 31, 2013 and 2012, respectively. The overall $653 million (42%) unfavorable change from year-end 2012 was primarily due to (i) an increase in "Accrued contingencies," due largely to certain KMP transportation rate case liabilities being reclassified from long-term liabilities to short-term liabilities; (ii) a net increase in KMP's commercial paper borrowings; (iii) a net increase in KMI and its subsidiaries (excluding KMP and EPB and its subsidiaries') current maturities; and (iv) the sale in 2013 of our investment in BBPP Holdings Ltda and KMP's investment in the Express pipeline system, which were included at December 31, 2012 within "Assets held for sale." The overall increase in our working capital deficit was partially offset by a net decrease in KMI's credit facility borrowings. 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 combined cash and cash equivalent balances as a result of our or our subsidiaries' debt or equity issuances (discussed below in "—Long-term Financing").

KMP and EPB each employ centralized cash management programs for their U.S.-based bank accounts that essentially concentrates the cash assets of their operating partnerships and their 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 their operating partnerships and their subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within their consolidated group. KMP and EPB 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. However, KMP and EPB's cash and the cash of their subsidiaries are not concentrated into accounts of KMI or any company not in our consolidated group of companies, and KMI has no rights with respect to KMP and EPB's cash except as permitted pursuant to their respective partnership agreements.

Furthermore, certain of KMP and EPB's 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

From time to time, KMI, KMP or EPB issue long-term debt securities, often referred to as senior notes. All of the senior notes of KMI, KMP or EPB issued to date, other than those issued by KMP and EPB's subsidiaries and its operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. KMI and its subsidiaries' (other than KMP and its subsidiaries and EPB and its subsidiaries') senior notes are secured equally and ratably with KMI's $1.75 billion senior secured revolving credit facility. All of KMP and EPB's outstanding senior notes are unsecured obligations that rank equally with all of its other senior debt obligations. Secured debt has also been incurred by some of KMP's operating partnerships and subsidiaries. All of the fixed rate senior notes of KMI, KMP or EPB 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.

As of December 31, 2013 and 2012, the consolidated balances of long-term debt, including the current portion and the preferred interest in the general partner of KMP, but excluding debt fair value adjustments was $33,062 million and $30,154 million, respectively. 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.

During 2013, we paid down the EP acquisition debt using $947 million of proceeds from the March 2013 drop-down transaction and $239 million of proceeds from the sale of the remainder of the EPC building note to third parties in the second quarter of 2013. We anticipate that we will continue to reduce our debt balance with proceeds from future drop-down transactions.

Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. We and our subsidiaries, including KMP and EPB, are subject, however, to conditions in the equity and debt markets 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 equity markets, we would be required to either 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 or our subsidiaries' credit ratings. Furthermore, our subsidiaries' ability to access the public and private debt markets is affected by their respective credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our and our subsidiaries' credit ratings.

KMI and some of its direct and indirect subsidiaries (referred to as the Combined Other Guarantor Subsidiaries), guarantee the payment of certain of El Paso's (formerly known as El Paso Corporation) outstanding debt. As of the successor date of August 13, 2012, each series of El Paso outstanding notes in aggregate principal amount became guaranteed on a senior unsecured basis by KMI and the Combined Other Guarantor Subsidiaries. As of December 31, 2013 and 2012, approximately $3.8 billion and $3.9 billion, respectively, in aggregate principal amount of these series of El Paso senior notes is outstanding. See Note 19 "Guarantee of Securities of Subsidiaries" to our consolidated financial statements.

For additional information about our debt-related transactions in 2013, see Note 8 "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. Capital expenditures include those that are maintenance/sustaining capital expenditures and those that are capital additions and improvements (which we refer to as expansion, or discretionary capital expenditures). These distinctions are used when determining cash from operations pursuant to the MLP partnership agreements (which is distinct from GAAP cash flows from operating activities). Capital additions and improvements 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 cash from operations. Maintenance capital expenditures are those which maintain throughput or capacity. Thus under the MLP partnership agreements, the distinction between maintenance capital expenditures and capital additions and improvements is a physical determination rather than an economic one.

Generally, the determination of whether a capital expenditure is classified as maintenance or as capital additions and improvements is made on a project level. The classification of the MLP's capital expenditures as capital additions and improvements or as maintenance capital expenditures under the partnership agreements is left to the good faith determination of KMGP as KMP's general partner and El Paso Pipeline GP Company, L.L.C. as EPB's general partner, which is deemed conclusive.

Generally we fund our sustaining capital expenditures with existing cash or from cash flows from operations, and we initially fund our discretionary capital expenditures through borrowings under our credit facilities (or commercial paper program for KMP) until the amount borrowed is of a sufficient size to cost effectively replace the initial funding with long-term debt, or equity, or both.

Our capital expenditures for the year ended December 31, 2013, and the amount we expect to spend for 2014 to sustain and grow our business are as follows (in millions):

	2013	Expected 2014
Sustaining capital expenditures		
KMP	$ 327	$ 438
EPB	39	47
KMI	47	68
Total sustaining capital expenditures(a)	$ 413	$ 553
Discretionary capital expenditures(b)(c)	$ 3,602	$ 3,874

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(a) 2013 and Expected 2014 amounts include $47 million and $70 million, respectively, for our proportionate share of sustaining capital expenditures of certain unconsolidated joint ventures.

(b) 2013 amount (i) includes $543 million of discretionary capital expenditures of unconsolidated joint ventures and acquisitions; (ii) includes a combined $275 million net increase from accrued capital expenditures and contractor retainage; (iii) is reduced by $126 million related to contributions from KMP's noncontrolling interests to fund a portion of certain capital projects; and (iv) is reduced by $93 million related primarily to both casualty losses and other non-recurring items. 2013 amount also excludes the May 1, 2013 acquisition of Copano, but includes the discretionary capital expenditures of Copano, its subsidiaries and its unconsolidated joint ventures after KMP's May 1, 2013 acquisition date.

(c) Expected 2014 includes our contributions to certain unconsolidated joint ventures and small acquisitions, 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 KMP's and EPB's obligations with respect to these investments, as well as KMP's and EPB's obligations with respect to related letters of credit, see Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 6 "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	$ 34,216	$ 2,306	$ 4,591	$ 4,885	$ 22,434
Interest payments(a)	23,464	1,848	3,486	2,935	15,195
Lease obligations(b)	432	70	109	76	177
Pension and postretirement welfare plans(c)	762	92	62	62	546
Transportation, volume and storage agreements(d)	938	115	217	191	415
Rights of way(e)	274	23	46	46	159
Other obligations(f)	493	149	180	34	130
Total	$ 60,579	$ 4,603	$ 8,691	$ 8,229	$ 39,056
Other commercial commitments:					
Standby letters of credit(g)	$ 535	$ 530	$ 5	$ —	$ —
Capital expenditures(h)	$ 900	$ 900	$ —	$ —	$ —

(a) 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, 2013.

(b) Represents commitments pursuant to the terms of operating lease agreements.

(c) 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 2014 and estimated benefit payments for unfunded plans in all years.

(d) Primarily represents KMP and EPB transportation agreements of $396 million, volume agreements of $256 million and storage agreements for capacity on third party and an affiliate pipeline systems of $145 million.

(e) Represents liabilities for rights-of-way.

(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 $535 million in letters of credit outstanding as of December 31, 2013 consisted of the following (i) $170 million under six letters of credit related to power and marketing purposes; (ii) $87 million under fourteen letters of credit for insurance purposes; (iii) a $100 million letter of credit that supports certain proceedings with the CPUC involving refined products tariff charges on the intrastate common carrier operations of KMP’s Pacific operations’ pipelines in the state of California; (iv) KMP’s $30 million guarantee under letters of credit totaling $46 million supporting KMP’s International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (v) a $38 million letter of credit supporting KMP’s pipeline and terminal operations in Canada; (vi) a $25 million letter of credit supporting KMP’s Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (vii) a $24 million letter of credit supporting KMP’s Kinder Morgan Operating L.P. “B” tax-exempt bonds; (viii) a $14 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; and (ix) a combined $32 million in twenty-one letters of credit supporting environmental and other obligations of us and our subsidiaries.

(h) Represents commitments for the purchase of plant, property and equipment as of December 31, 2013.

Cash Flows

The following table summarizes our net cash flows from operating, investing and financing activities for each period presented.

	Year Ended December 31, 2013	2012	Increase/Decrease
	(In millions)		
Net Cash Provided by (Used in)			
Operating activities	$ 4,064	$ 2,795	$ 1,269
Investing activities	(3,064)	(5,084)	2,020
Financing activities	(1,095)	2,584	(3,679)
Effect of Exchange Rate Changes on Cash	(21)	8	(29)
Net (Decrease) Increase in Cash and Cash Equivalents	$ (116)	$ 303	$ (419)

Operating Activities

The net increase of $1,269 (45%) million in cash provided by operating activities in 2013 compared to 2012 was primarily attributable to:

- a $1 billion increase in cash from overall higher net income after adjusting our period-to-period $2 billion increase in net income for non-cash items primarily consisting of higher net gains from both the sale and the remeasurement of net assets to fair value; the 2013 gain on the sale of KMP's investments in the Express pipeline system; DD&A; deferred income taxes; earnings from equity investments; higher gains in 2013 from the sale and/or write-off of property, plant and equipment; and an increase in transportation rate case liabilities and legal liabilities.

Investing Activities

The $2,020 million net decrease in cash used in investing activities in 2013 compared to 2012 was primarily attributable to:

- a $4,761 million decrease due to less cash used in the acquisitions of assets and investments from unrelated parties primarily driven by the $4,970 million net outlay of cash in 2012 for the EP acquisition;

- a combined $490 million of proceeds we received in 2013 from both KMP's sale of the investments in the Express pipeline system and our sale of BBPP Holding Ltds (both discussed in Note 3 "Acquisitions and Divestitures" to our consolidated financial statements;)

- a $1,791 million of net proceeds received in 2012 (after paying selling costs) from the disposal of KMP's FTC Natural Gas Pipelines disposal group; and

- a $1,347 million increase in cash used in investing activities in 2013 due to higher capital expenditures, as described above in "—Capital Expenditures."

Financing Activities

The net decrease of $3,679 million in cash from financing activities in 2013 compared to 2012 was primarily attributable to:

- a $2,132 million net decrease in cash from overall debt financing activities primarily due to (i) $5,288 billion of proceeds from the EP acquisition debt issued in the second quarter of 2012; (ii) lower debt repayments of $1,475 million resulting from the $1,186 million of repayments made on the acquisition debt in 2013, compared to the $2,661 million of repayments made on the EP acquisition debt in 2012. Further information regarding the March 2013 drop-down transaction and acquisition debt is discussed in Note 3 "Acquisitions and Divestitures—-Drop-down of EP

Assets to KMP" and Note 8 "Debt—KMI," respectively, to our consolidated financial statements; and (iii) a $1,695 million net decrease in our and our subsidiaries other debt repayments and debt issuances.

- a $480 million decrease in cash due to higher combined repurchases of shares and warrants;

- a $473 million decrease in cash associated with distributions to noncontrolling interests, primarily reflecting the increased distributions to common unit owners by KMP and EPB;

- a $438 million decrease in cash due to higher dividend payments; and

- a $233 million decrease in contributions provided by noncontrolling interests, primarily reflecting the following (i) $141 million less proceeds from the sales of additional KMP common units in 2013 versus 2012; and (ii) $187 million less proceeds EPB received from its issuance of common units in 2013 versus 2012 excluding the common units issued to its general partner. These decreases were partially offset by the $86 million increase in cash, due to an increase in other noncontrolling interests contributions, mainly due to the incremental contributions KMP received from its BOSTCO partners in 2013.

KMI Dividends

Our board of directors has adopted the dividend policy set forth in our shareholders' agreement, which provides that, subject to applicable law, we will pay quarterly cash dividends on all classes of our capital stock equal to the cash we receive from our subsidiaries and other sources less any cash disbursements and reserves established by a majority vote of our board of directors, including for general and administrative expenses, interest and cash taxes. The division of our dividends among our various classes of capital stock that were outstanding prior to December 26, 2012 (discussed further following) was in accordance with our charter. Our board of directors may declare dividends by a majority vote in accordance with our dividend policy pursuant to our bylaws. This policy reflects our judgment that our stockholders would be better served if we distributed to them a substantial portion of our cash. As a result, we may not retain a sufficient amount of cash to fund our operations or to finance unanticipated capital expenditures or growth opportunities, including acquisitions.

Three months ended	Total quarterly dividend per share for the period		Date of declaration	Date of record	Date of dividend
December 31, 2012	$	0.37	January 16, 2013	January 31, 2013	February 15, 2013
March 31, 2013	$	0.38	April 17, 2013	April 29, 2013	May 16, 2013
June 30, 2013	$	0.40	July 17, 2013	July 31, 2013	August 15, 2013
September 30, 2013	$	0.41	October 16, 2013	October 31, 2013	November 15, 2013
December 31, 2013	$	0.41	January 15, 2014	January 31, 2014	February 18, 2014

As shown in the table above, we declared dividends of $1.60 per share for 2013, a 14% increase over our 2012 declared dividends of $1.40 per share.

On December 26, 2012, the remaining outstanding shares of our Class A, Class B, and Class C common stock were fully converted into Class P shares and as of December 31, 2012 only our Class P common stock was outstanding. Prior to the above common stock conversions, dividends on our Class A, Class B and Class C common stock (investor retained stock) generally were paid at the same time as dividends on our common stock and were based on the aggregate number of shares of common stock into which our investor retained stock was convertible on the record date for the applicable dividend. The portion of our dividends payable on the three classes of our investor retained stock varied among those classes, but the variations did not affect the dividends we paid on our common stock since the total number of shares of common stock into which our investor retained stock could convert in the aggregate was fixed on the closing of our initial public offering.

Our board of directors may amend, revoke or suspend our dividend policy at any time and for any reason. There is nothing in our dividend policy or our governing documents that prohibits us from borrowing to pay dividends. The actual amount of dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, market opportunities, our capital requirements, legal, regulatory and contractual constraints, tax laws and other factors. In particular, distributions received from KMP continue to be the most significant source of our cash available to pay dividends. Our ability to pay and increase dividends to our stockholders is primarily dependent on distributions received from KMP and EPB.

Our 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. We pay our dividends after we receive quarterly distributions from KMP and EPB, which are paid within 45 days after the end of each quarter, generally on or about the 15th day of each February, May, August and November. Therefore, our dividend generally will be paid on or about the 16th day of each February, May, August and November. If the day after we receive KMP's and EPB's distributions is not a business day, we expect to pay our dividend on the business day immediately following.

Recent Accounting Pronouncements

Please refer to Note 17 "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 take steps to hedge, or limit our exposure to, 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 or KMP 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.

As part of the EP acquisition, we acquired power forward and swap contracts. We have entered into offsetting positions that eliminate the price risks associated with our power contracts. As part of the May 1, 2013 Copano acquisition, KMP acquired derivative contracts related to natural gas, NGL and crude oil. None of these derivatives are designated as accounting hedges.

Fundamentally, our hedging strategy involves taking a simultaneous financial position in the futures market that is equal and opposite to our physical position, or anticipated position, in the cash market (or physical product) in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, KMP often enters into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of its crude oil or the margin from the sale and purchase of its natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative. A hedge is successful to the extent gains or losses in the cash market are neutralized by losses or gains in the futures transaction.

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
J. Aron & Company / Goldman Sachs	A-
Bank of America / Merrill Lynch	A-
Natixis	A
Morgan Stanley	A-
J.P. Morgan	A

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 and our subsidiaries to undertake further capital improvement projects, attain budget results and meet dividend/distribution 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. Cash flow hedges are defined as hedges made with the intention of decreasing the variability in cash flows related to future transactions, as opposed to the value of an asset, liability or firm commitment, and we are allowed special hedge accounting treatment for such derivative contracts.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, outside "Net Income" reported in our consolidated statements of income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income, pending occurrence of the expected transaction. Other comprehensive income consists of those financial items that are within "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income (portions attributable to our noncontrolling interests are within "Noncontrolling interests" and are not included in our net income). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

All remaining gains and losses on the derivative contracts (the ineffective portion and those contracts not designated as hedges) are included in current net income. The ineffective portion of the gain or loss on the derivative contracts is the difference between the gain or loss from the change in value of the derivative contract and the effective portion of that gain or loss. In addition, when the hedged forecasted transaction does take place and affects earnings, the effective part of the hedge is also recognized in the income statement, and the earlier recognized effective amounts are removed from "Accumulated other comprehensive loss" (and "Noncontrolling interests") and are transferred to the income statement as well, effectively offsetting the changes in cash flows stemming from the hedged risk. If the forecasted transaction results in an asset or liability, amounts should be reclassified into earnings when the asset or liability affects earnings through cost of sales, depreciation, interest expense, etc.

We measure the risk of price changes in the natural gas, 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, 2013 and 2012, a hypothetical 10% movement in underlying commodity natural gas prices would affect the estimated fair value of natural gas derivatives, held by us and KMP, by $15 million and $7 million, respectively. As of both December 31, 2013 and 2012, a hypothetical 10% movement in underlying commodity crude oil prices would affect the estimated fair value of crude oil derivatives, held by KMP, by $201 million and $196 million, respectively. As of December 31, 2013, a hypothetical 10% movement in underlying commodity NGL prices would affect the estimated fair value of KMP's NGL derivatives by $5 million. As of December 31, 2013, a hypothetical 10% movement in underlying commodity electricity prices would not affect the estimated fair value of our power derivatives. As of December 31, 2012, a hypothetical 10% movement in underlying commodity electricity prices would affect the estimated fair value of our power derivatives by $2 million. 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, crude oil, NGL and power portfolios of derivative contracts (including commodity futures and options contracts, fixed price swaps and basis swaps) 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, 2013 and 2012, the carrying values of the fixed rate debt (including the debt fair value adjustments) were $33,129 million and $29,554 million, respectively. These amounts compare to, as of December 31, 2013 and 2012, fair values of $33,185 million and $31,882 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 2013 and 2012, would result in changes of approximately $1,185 million and $1,048 million, respectively, in the fair values of these instruments.

The carrying value of the variable rate debt (which approximates the fair value), excluding the value of interest rate swap agreements (discussed following), was $3,064 million and $4,847 million as of December 31, 2013 and 2012, respectively. As of December 31, 2013, KMI and KMP were party to interest rate swap agreements with notional principal amounts of $725 million and $4,675 million, respectively. As of December 31, 2012, KMI and KMP were party to interest rate swap agreements with notional principal amounts of $725 million and $5,525 million, respectively. An interest rate swap agreement is a contractual agreement entered into between two counterparties under which each agrees to make periodic interest payments to the other for an agreed period of time based upon a predetermined amount of principal, which is called the notional principal amount. Normally at each payment or settlement date, the party who owes more pays the net amount; so at any given settlement date only one party actually makes a payment. The principal amount is notional because there is no need to exchange actual amounts of principal. A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 51 basis points in 2013 and approximately 49 basis points in 2012) when applied to our outstanding balance of variable rate debt as of December 31, 2013 and 2012, including adjustments for the notional swap amounts described above, would result in changes of approximately $43 million and $55 million, respectively, in our 2013 and 2012 annual pre-tax earnings. As of both December 31, 2013 and 2012, EPB had no interest rate swap agreements outstanding.

Interest rate swap agreements are entered into for the purpose of transforming 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 through our subsidiaries, 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. In general, KMP attempts to maintain an overall target mix of approximately 50% fixed rate debt and 50% of variable rate debt, and typically KMI, excluding KMP, targets well below that level for variable rate debt. As of December 31, 2013, approximately 27% of KMI's debt, excluding that of KMP and EPB, is variable rate debt.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 13 "Risk Management" to our consolidated financial statements.

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 103.

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, 2013, 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 (1992)* 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, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

We acquired the full ownership interest in Copano effective May 1, 2013. Copano provides comprehensive services to natural gas producers, including natural gas gathering, processing, treating and NGL fractionation. Its operations are located primarily in Texas, Oklahoma and Wyoming. We included most of Copano’s businesses within our Natural Gas Pipelines business segment; however, we included its 50% equity ownership interest in Double Eagle Pipeline LLC within our Products Pipelines business segment. We excluded all of the acquired Copano businesses from the scope of our management’s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2013. Copano constituted 9% of our total revenues for 2013 and 8% of our total assets as of December 31, 2013.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2013 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 2013 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2013.

Item 11. *Executive Compensation.*

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2013 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2013.

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 2013 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2013.

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 2013 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2013.

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 2013 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2013.

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 103.

The financial statements, including the notes thereto, of KMP and EPB , consolidated subsidiaries of Kinder Morgan, Inc., are incorporated herein by reference to pages 106 through 185 of Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2013 and pages 63 through 98 of El Paso Pipeline Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2013.

(3) Exhibits

Exhibit Number		Description
2.1*	—	Agreement and Plan of Merger, dated as of October 16, 2011, among Kinder Morgan, Inc., Sherpa Merger Sub, Inc., Sherpa Acquisition, LLC, Sirius Holdings Merger Corporation, Sirius Merger Corporation and El Paso Corporation (included as Annex A to the information statement/proxy statement/prospectus forming a part of Kinder Morgan, Inc.'s Registration Statement on Form S-4 (File No. 333-177895) filed on November 10, 2011)
2.2*	—	Agreement and Plan of Merger, dated as of October 16, 2011, by and among El Paso Corporation, Sirius Holdings Merger Corporation and Sirius Merger Corporation (included as Annex B to the information statement/proxy statement/prospectus forming a part of Kinder Morgan, Inc.'s Registration Statement on Form S-4 (File No. 333-177895) filed on November 10, 2011)
3.1*	—	Certificate of Incorporation of Kinder Morgan, Inc. (filed as Exhibit 3.1 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-35081) (the "KMI 10-Q"))
3.2*	—	Amended and Restated Bylaws of Kinder Morgan, Inc. (filed as Exhibit 3.1 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 (File No. 1-35081))
4.1*	—	Form of certificate representing Class P common shares of Kinder Morgan, Inc. (filed as Exhibit 4.1 to Kinder Morgan, Inc.'s Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2*	—	Shareholders Agreement among Kinder Morgan, Inc. and certain holders of common stock (filed as Exhibit 4.2 to the KMI 10-Q)
4.3*	—	Amendment No. 1 to the Shareholders Agreement among Kinder Morgan, Inc. and certain holders of common stock (filed as Exhibit 4.3 Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 30, 2012 (File No. 1-35081))
4.4*	—	Warrant Agreement, dated as of May 25, 2012, among Kinder Morgan, Inc., Computershare Trust Company, N.A. and Computershare Inc., as Warrant Agent (filed as Exhibit 4.1 to Kinder Morgan Inc.'s Current Report on Form 8-K filed on May 30, 2012 (File No. 1-35081))
10.1*	—	Kinder Morgan, Inc. 2011 Stock Incentive Plan (filed as Exhibit 10.1 to the KMI 10-Q)
10.2*	—	Form of Restricted Stock Agreement (filed as Exhibit 10.2 to the KMI 10-Q)
10.3*	—	Kinder Morgan, Inc. Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.4 to the KMI 10-Q)
10.4*	—	Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to the KMI 10-Q)
10.5*	—	Kinder Morgan, Inc. Employees Stock Purchase Plan (filed as Exhibit 10.5 to the KMI 10-Q)
10.6*	—	Kinder Morgan, Inc. Annual Incentive Plan (filed as Exhibit 10.6 to the KMI 10-Q)
10.7*	—	Employment Agreement dated October 7, 1999, between K N Energy, Inc. and Richard D. Kinder (filed as Exhibit 99.D of the Schedule 13D filed by Mr. Kinder on November 16, 1999 (File No. 5-06259))
10.8*	—	Form of Purchase Provisions between Kinder Morgan Management, LLC and Kinder Morgan Kansas, Inc. (included as Annex B to the Second Amended and Restated Limited Liability Company Agreement of Kinder Morgan Management, LLC filed as Exhibit 3.1 to Kinder Morgan Management, LLC's Current Report on Form 8-K filed on May 30, 2007 (File No. 1-16459))
10.9*	—	Credit Agreement, dated as of May 30, 2007, among Kinder Morgan Kansas, Inc. and Kinder Morgan Acquisition Co., as the borrower, the several lenders from time to time parties thereto, and Citibank, N.A., as administrative agent and collateral agent (filed as Exhibit 10.10 to Kinder Morgan, Inc.'s Registration Statement on Form S-1 filed on December 30, 2010 (File No. 333-170773))

10.10*	—	Registration Rights Agreement among Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and Kinder Morgan Kansas, Inc. dated May 18, 2001 (filed as Exhibit 4.7 to Kinder Morgan Kansas, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 1-06446))
10.11*	—	Form of Indenture dated as of August 27, 2002 between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100338))
10.12*	—	Form of First Supplemental Indenture dated as of December 6, 2002 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-4 filed on January 31, 2003 (File No. 333-102873))
10.13*	—	Form of 6.50% Note due 2012 (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100338))
10.14*	—	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))
10.15*	—	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))
10.16*	—	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))
10.17*	—	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))
10.18*	—	Form of Indemnification Agreement between Kinder Morgan Kansas, Inc. and each member of the Special Committee of the Board of Directors formed in connection with the Going Private Transaction (filed as Exhibit 10.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on June 16, 2006 (File No. 1-06446))
10.19*	—	Delegation of Control Agreement among Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001 (File No. 1-11234))
10.20*	—	Amendment No. 1 to Delegation of Control Agreement, dated as of July 20, 2007, among Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K on July 20, 2007 (File No. 1-11234))
10.21*	—	Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001 (File No. 1-11234))
10.22*	—	Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed November 22, 2004 (File No. 1-11234))
10.23*	—	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed May 5, 2005 (File No. 1-11234))
10.24*	—	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed April 21, 2008 (File No. 1-11234))
10.25*	—	Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.5 to Kinder Morgan Energy Partners, L.P. Form 10-K 2012 (File No. 1-11234))
10.26*	—	Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors (filed as Exhibit 10.2 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005 (File No. 1-11234))
10.27*	—	Form of Common Unit Compensation Agreement entered into with Non-Employee Directors (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005 (File No. 1-11234))
10.28*	—	Credit Agreement dated as of June 23, 2010 among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. "B", the lenders party thereto, Wells Fargo Bank, National Association as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A., and DnB NOR Bank ASA (filed as exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Current Report on Form 8-K filed June 24, 2010 (File No. 1-11234))

10.29*	—	First Amendment to Credit Agreement, dated as of July 1, 2011, among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. “B”, the lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 1-11234))
10.30*	—	Indenture dated as of January 29, 1999 among Kinder Morgan Energy Partners, L.P., the guarantors listed on the signature page thereto and U.S. Trust Company of Texas, N.A., as trustee, relating to Senior Debt Securities (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K filed February 16, 1999 (File No. 1-11234))
10.31*	—	Indenture dated November 8, 2000 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as Trustee (filed as Exhibit 4.8 to Kinder Morgan Energy Partners, L.P.’s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-11234))
10.32*	—	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. Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))
10.33*	—	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. Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
10.34*	—	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. Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))
10.35*	—	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. Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.36*	—	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. Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
10.37*	—	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 the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.38*	—	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. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.39*	—	Form of 7.30% Note (contained in the Indenture filed as Exhibit 4.1 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
10.40*	—	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.41*	—	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))
10.42*	—	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 5.00% Notes due December 15, 2013 (filed as Exhibit 4.25 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 1-11234))
10.43*	—	Certificate of Executive Vice President 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 5.125% Notes due November 15, 2014 (filed as Exhibit 4.27 to Kinder Morgan Energy Partners, L.P. Annual Report on Form 10-K for the year ended December 3, 2004 (File No. 1-11234))
10.44*	—	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. Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))
10.45*	—	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. Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))

10.46*	—	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. Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))
10.47*	—	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 5.85% Senior Notes due 2012 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 (File No. 1-11234))
10.48*	—	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. Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 1-11234))
10.49*	—	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. Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 1-11234))
10.50*	—	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. Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-11234))
10.51*	—	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. Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))
10.52*	—	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. Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))
10.53*	—	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))
10.54*	—	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))
10.55*	—	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-K for the quarter ended March 31, 2011)
10.56*	—	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-K for the quarter ended September 30, 2011)
10.57*	—	Severance Agreement with C. Park Shaper (filed as Exhibit 10.7 to the KMI 10-Q)
10.58*	—	Severance Agreement with Steven J. Kean (filed as Exhibit 10.8 to the KMI 10-Q)
10.59*	—	Severance Agreement with Kimberly A. Dang (filed as Exhibit 10.9 to the KMI 10-Q)
10.60*	—	Severance Agreement with Joseph Listengart (filed as Exhibit 10.10 to the KMI 10-Q)
10.61*	—	Debt Commitment Letter between Kinder Morgan, Inc. and Barclays Capital PLC, dated as of October 16, 2011 (filed as Exhibit 10.71 to Kinder Morgan, Inc.'s Registration Statement on Form S-4 filed on December 14, 2011 (File No. 333-177895))
12.1	—	Statement re: computation of ratio of earnings to fixed charges.
21.1	—	Subsidiaries of Kinder Morgan, Inc.
23.1	—	Consent of PricewaterhouseCoopers LLP.
23.2	—	Consent of Netherland, Sewell & Associates, Inc.
23.3	—	Consent of Ryder Scott Company, L.P.

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*	—	The financial statements of Kinder Morgan Energy Partners, L.P. and subsidiaries (incorporated by reference to pages 106 through 185 of the Annual Report on Form 10-K of Kinder Morgan Energy Partners, L.P. for the year ended December 31, 2013, filed on February 18, 2014).
99.2*	—	The financial statements of El Paso Pipeline Partners, L.P. and subsidiaries (incorporated by reference to pages 63 through 98 of the Annual Report on Form 10-K of El Paso Pipeline Partners, L.P. for the year ended December 31, 2013, filed on February 19, 2014).
99.3	—	Netherland, Sewell & Associates, Inc.'s report of estimates of the net reserves and future net revenues, as of December 31, 2013, related to Kinder Morgan CO_2 Company, L.P.'s interest in certain oil and gas properties located in the state of Texas.
99.4	—	Ryder Scott Company, L.P.'s report of estimates of the net reserves and future net revenues, as of December 31, 2013, 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, 2013, 2012, and 2011; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012, and 2011; (iii) our Consolidated Balance Sheets as of December 31, 2013 and 2012; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012, and 2011; (v) our Consolidated Statement of Stockholders' Equity as of and for the years ended December 31, 2013, 2012, and 2011; and (vi) the notes to our Consolidated Financial Statements.

*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

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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 2013 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 2013 Annual Report on Form 10-K, management has excluded Copano Energy, L.L.C. from its assessment of internal control over financial reporting as of December 31, 2013 because it was acquired in a purchase business combination by Kinder Morgan Energy Partners, L.P. on May 1, 2013. We have also excluded Copano Energy, L.L.C. from our audit of internal control over financial reporting. Copano Energy, L.L.C. is a wholly-owned subsidiary whose total assets and total revenues represent 8% and 9%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2013.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2014

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

	Year Ended December 31,		
	2013	2012	2011
Revenues			
Natural gas sales	$ 3,605	$ 2,511	$ 3,305
Services	6,677	5,013	3,050
Product sales and other	3,788	2,449	1,588
Total Revenues	14,070	9,973	7,943
Operating Costs, Expenses and Other			
Costs of sales	5,253	3,057	3,278
Operations and maintenance	2,112	1,702	1,491
Depreciation, depletion and amortization	1,806	1,419	1,068
General and administrative	613	929	515
Taxes, other than income taxes	395	286	174
Other income, net	(99)	(13)	(6)
Total Operating Costs, Expenses and Other	10,080	7,380	6,520
Operating Income	3,990	2,593	1,423
Other Income (Expense)			
Earnings from equity investments	327	153	226
Amortization of excess cost of equity investments	(39)	(23)	(7)
Interest, net	(1,675)	(1,399)	(682)
Gain (loss) on remeasurement of previously held equity investments to fair value (Note 3)	558	—	(167)
Gain on sale of investments in Express pipeline system (Note 3)	224	—	—
Other, net	53	19	17
Total Other Income (Expense)	(552)	(1,250)	(613)
Income from Continuing Operations Before Income Taxes	3,438	1,343	810
Income Tax Expense	(742)	(139)	(361)
Income from Continuing Operations	2,696	1,204	449
Discontinued Operations (Note 3)			
Income from operations of KMP's FTC Natural Gas Pipelines disposal group and other, net of tax	—	160	211
Loss on sale and the remeasurement of KMP's FTC Natural Gas Pipelines disposal group to fair value, net of tax	(4)	(937)	—
(Loss) Income from Discontinued Operations, Net of Tax	(4)	(777)	211
Net Income	2,692	427	660
Net Income Attributable to Noncontrolling Interests	(1,499)	(112)	(66)
Net Income Attributable to Kinder Morgan, Inc.	$ 1,193	$ 315	$ 594

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

	Year Ended December 31,		
	2013	**2012**	**2011**
Class P Shares			
Basic and Diluted Earnings Per Common Share From Continuing Operations	$ 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	$ 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 Shares Outstanding			
Class P Shares	1,036	461	118
Class A Shares		446	589
Diluted Weighted-Average Number of Shares Outstanding			
Class P Shares	1,036	908	708
Class A Shares		446	589
Dividends Per Common Share Declared for the Period	$ 1.60	$ 1.40	$ 1.05

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,		
	2013	**2012**	**2011**
Kinder Morgan, Inc.			
Net income	$ 1,193	$ 315	$ 594
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax benefit (expense) of $6, $(19) and $(5), respectively)	(14)	32	6
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(2), $3 and $(36), respectively)	4	(5)	67
Foreign currency translation adjustments (net of tax benefit (expense) of $22, $(8), and $8, respectively)	(49)	14	(14)
Benefit plan adjustments (net of tax (expense) benefit of $(86), $34 and $25, respectively)	151	(53)	(45)
Benefit plan amortization (net of tax expense of $(2), $(4) and $(4), respectively)	2	9	7
Total other comprehensive income (loss)	94	(3)	21
Total comprehensive income	1,287	312	615
Noncontrolling Interests			
Net income	1,499	112	66
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax benefit (expense) of $4, $(7) and $(1), respectively)	(24)	50	7
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(1), $- and $(13), respectively)	7	(3)	117
Foreign currency translation adjustments (net of tax benefit (expense) of $9, $(2) and $2, respectively)	(54)	18	(21)
Benefit plan adjustments (net of tax (expense) benefit of $(3), $- and $2, respectively)	15	13	(16)
Benefit plan amortization (net of tax benefit (expense) of $-, $- and $-, respectively)	2	(4)	—
Total other comprehensive (loss) income	(54)	74	87
Total comprehensive income	1,445	186	153
Total			
Net income	2,692	427	660
Other comprehensive income (loss), net of tax			
Change in fair value of derivatives utilized for hedging purposes (net of tax benefit (expense) of $10, $(26) and $(6), respectively)	(38)	82	13
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(3), $3 and $(49), respectively)	11	(8)	184
Foreign currency translation adjustments (net of tax benefit (expense) of $31, $(10) and $10, respectively)	(103)	32	(35)
Benefit plan adjustments (net of tax (expense) benefit of $(89), $34 and $27, respectively)	166	(40)	(61)
Benefit plan amortization (net of tax expense of $(2), $(4) and $(4), respectively)	4	5	7
Total other comprehensive income	40	71	108
Total comprehensive income	$ 2,732	$ 498	$ 768

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,	
	2013	**2012**
ASSETS		
Current assets		
Cash and cash equivalents – KMI (Note 18)	$ 116	$ 71
Cash and cash equivalents – KMP and EPB (Note 18)	482	643
Accounts receivable, net	1,721	1,333
Inventories	430	374
Assets held for sale	—	298
Deferred income taxes	567	539
Other current assets	552	416
Total current assets	3,868	3,674
Property, plant and equipment, net (Note 5)	35,847	30,996
Investments	5,951	5,804
Goodwill (Note 7)	24,504	23,632
Other intangibles, net	2,438	1,171
Deferred charges and other assets	2,577	2,968
Total Assets	$ 75,185	$ 68,245
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt - KMI (Note 18)	$ 725	$ 1,153
Current portion of debt - KMP and EPB (Note 18)	1,581	1,248
Accounts payable	1,676	1,248
Accrued interest	565	513
Accrued contingencies	584	114
Other current liabilities	944	952
Total current liabilities	6,075	5,228
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding - KMI (Note 18)	9,221	9,148
Outstanding - KMP and EPB (Note 18)	22,589	20,161
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	1,977	2,591
Total long-term debt	33,887	32,000
Deferred income taxes	4,651	4,071
Other long-term liabilities and deferred credits	2,287	2,846
Total long-term liabilities and deferred credits	40,825	38,917
Total Liabilities	$ 46,900	$ 44,145

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

	December 31,	
	2013	**2012**
Commitments and contingencies (Notes 8, 12 and 16)		
Stockholders' Equity		
Class P shares, $0.01 par value, 2,000,000,000 shares authorized, 1,030,677,076 and 1,035,668,596 shares, respectively, issued and outstanding	$ 10	$ 10
Preferred stock, $0.01 par value, 10,000,000 shares authorized, none outstanding	—	—
Additional paid-in capital	14,479	14,917
Retained deficit	(1,372)	(943)
Accumulated other comprehensive loss	(24)	(118)
Total Kinder Morgan, Inc.'s stockholders' equity	13,093	13,866
Noncontrolling interests	15,192	10,234
Total Stockholders' Equity	28,285	24,100
Total Liabilities and Stockholders' Equity	$ 75,185	$ 68,245

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,		
	2013	2012	2011
Cash Flows From Operating Activities			
Net income	$ 2,692	$ 427	$ 660
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	1,806	1,426	1,092
Deferred income taxes	640	47	84
Amortization of excess cost of equity investments	39	23	7
(Gain) loss 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)	859	167
Gain from sale of investments in Express pipeline system (Note 3)	(224)	—	—
Loss on early extinguishment of debt	—	82	—
Noncash compensation expense on settlement of EP stock awards	—	87	—
Earnings from equity investments	(327)	(223)	(313)
Distributions from equity investment earnings	398	381	287
Proceeds from termination of interest rate swap agreements	96	53	73
Pension contributions in excess of expense	(59)	(7)	—
Changes in components of working capital, net of the effects of acquisitions			
Accounts receivable	(131)	(231)	8
Inventories	(53)	(92)	(36)
Other current assets	(24)	32	(10)
Accounts payable	(36)	70	29
Accrued interest	42	(26)	19
Accrued contingencies and other current liabilities	(100)	(68)	(35)
Rate reparations, refunds and other litigation reserve adjustments	174	(39)	171
Other, net	(313)	(6)	163
Net Cash Provided by Operating Activities	4,064	2,795	2,366
Cash Flows From Investing Activities			
Acquisition of EP, net of $6,581 cash acquired (Note 3)	—	(4,970)	—
Acquisitions of other assets and investments, net of cash acquired	(292)	(83)	(1,179)
Proceeds from sales of assets and investments	490	—	—
Proceeds from disposal of discontinued operations (Note 3)	—	1,791	—
Repayments from related party	11	76	31
Capital expenditures	(3,369)	(2,022)	(1,200)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	87	154	23
Contributions to investments	(217)	(192)	(371)
Distributions from equity investments in excess of cumulative earnings	185	200	236
Other, net	41	(38)	68
Net Cash Used in Investing Activities	(3,064)	(5,084)	(2,392)
Cash Flows From Financing Activities			
Issuance of debt – KMI	3,267	8,218	2,070
Payment of debt – KMI	(3,631)	(5,693)	(2,399)
Issuance of debt – KMP and EPB	10,314	9,930	7,502
Payment of debt – KMP and EPB	(8,762)	(9,062)	(6,394)
Debt issue costs	(38)	(111)	(76)
Cash dividends/distributions (Note 10)	(1,622)	(1,184)	(770)
Repurchases of shares and warrants	(637)	(157)	—
Contributions from noncontrolling interests	1,706	1,939	970
Distributions to noncontrolling interests	(1,692)	(1,219)	(956)
Other, net	—	(77)	(4)
Net Cash (Used in) Provided by Financing Activities	(1,095)	2,584	(57)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(21)	8	(8)

Net (decrease) increase in Cash and Cash Equivalents	(116)	303	(91)
Cash and Cash Equivalents, beginning of period	714	411	502
Cash and Cash Equivalents, end of period	$ 598	$ 714	$ 411

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

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

	Year Ended December 31,		
	2013	**2012**	**2011**
Noncash Investing and Financing Activities			
Net assets and liabilities acquired by the issuance of shares and warrants	$ —	$ 11,454	$ —
Assets acquired by the assumption or incurrence of liabilities	$ 1,510	$ —	$ 207
Assets acquired or liabilities settled by contributions from noncontrolling interests	$ 3,733	$ 306	$ 24
Increase in property, plant and equipment from both accruals and contractor retainage	$ 276	$ 83	$ 35
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	$ 1,652	$ 1,349	$ 681
Cash paid during the period for income taxes (net of refunds)	$ 67	$ 182	$ 277

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

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

	KMI Members	Par value of common shares	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2010	$ 3,575	$ —	$ —	$ —	$ (136)	$ 3,439	$ 5,100	$ 8,539
Reclassification of equity upon the offering	(3,404)	8	3,396			—		—
Amortization of restricted shares			7			7		7
Impact from equity transactions of KMP			28			28	(44)	(16)
A-1 and B unit amortization	4					4		4
Net income	71			523		594	66	660
Distributions						—	(956)	(956)
Contributions						—	994	994
Cash distributions/dividends	(246)			(524)		(770)		(770)
Class A, Class B and Class C share conversions				(2)		(2)		(2)
Other comprehensive income					21	21	87	108
Balance at December 31, 2011	—	8	3,431	(3)	(115)	3,321	5,247	8,568
Issuance of shares for EP acquisition		3	10,598			10,601		10,601
Issuance of warrants for EP acquisition			863			863		863
Acquisition of EP noncontrolling interests						—	3,797	3,797
Warrants repurchased			(157)			(157)		(157)
EP Trust I Preferred security conversions			14			14		14
Class A, Class B and Class C share conversions		(1)	1	(71)		(71)		(71)
Amortization of restricted shares			14			14		14
Impact from equity transactions of KMP, EPB and KMR			64			64	(102)	(38)
Tax impact on stock based compensation			90			90		90
Net income				315		315	112	427
Distributions						—	(1,219)	(1,219)
Contributions						—	2,329	2,329
Cash dividends				(1,184)		(1,184)		(1,184)
Other			(1)			(1)	(4)	(5)
Other comprehensive (loss) income					(3)	(3)	74	71
Balance at December 31, 2012	—	10	14,917	(943)	(118)	13,866	10,234	24,100
Shares repurchased			(172)			(172)		(172)
Warrants repurchased			(465)			(465)		(465)
Warrants exercised			1			1		1
EP Trust I Preferred security conversions			3			3		3
Amortization of restricted shares			35			35		35
Impact from equity transactions of KMP, EPB and KMR			161			161	(254)	(93)
Tax impact on stock based compensation			1			1		1
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
Cash dividends				(1,622)		(1,622)		(1,622)
Other			(2)			(2)	3	1
Other comprehensive income					94	94	(54)	40
Balance at December 31, 2013	$ —	$ 10	$ 14,479	$ (1,372)	$ (24)	$ 13,093	$ 15,192	$28,285

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

1. General

Kinder Morgan, Inc. is the largest midstream and the third largest energy company in North America with a combined enterprise value, including its two publicly traded MLP subsidiaries, of approximately $110 billion and unless the context requires otherwise, references to "we," "us," "our," or "KMI" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. We own an interest in or operate approximately 80,000 miles of pipelines and 180 terminals. Our pipelines transport natural gas, gasoline, crude oil, CO_2 and other products, and our terminals store petroleum products and chemicals and handle such products as ethanol, coal, petroleum coke and steel.

We own an approximate 10% limited partner interest and the 2% general partner interest in KMP, a leading pipeline transportation and energy storage company and one of the largest publicly-traded pipeline limited partnerships in America. KMP's limited partner units are traded on the NYSE under the ticker symbol "KMP."

We also own an approximate 41% limited partner interest and the 2% general partner interest in EPB, as well as certain natural gas pipeline assets (see Notes 3 and 10). EPB's limited partner units are traded on the NYSE under the ticker symbol "EPB."

Our common stock trades on the NYSE under the symbol "KMI."

On February 16, 2011, we completed the initial public offering of our common stock (the offering). All of the common stock that was sold in the offering was sold by our existing investors consisting of funds advised by or affiliated with Goldman Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC. No members of management sold shares in the offering, and we did not receive any proceeds from the offering. During 2012, the funds advised by or affiliated with Goldman Sachs & Co., The Carlyle Group and Riverstone Holdings LLC, sold their remaining interests in KMI and representatives of these funds are no longer on our board. For additional information on the offering, see Note 10.

KMR, is a publicly traded Delaware LLC. KMGP, the general partner of KMP and a wholly-owned subsidiary of ours, owns all of KMR's voting shares. KMR, pursuant to a delegation of control agreement, has been delegated, to the fullest extent permitted under Delaware law, all of KMGP's power and authority to manage and control the business and affairs of KMP, subject to KMGP's right to approve certain transactions.

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. Canadian dollars are designated as C$.

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.

Our consolidated financial statements include our accounts and the of our majority-owned and controlled subsidiaries as well as the accounts of KMP, EPB and KMR. Investments in jointly owned operations in which we hold a 50% or less interest (other than KMP, EPB and KMR, because we have the ability to exercise significant control over their operating and financial policies) are accounted for under the equity method.

Notwithstanding the consolidation of KMP and EPB and their respective subsidiaries into our financial statements, we are not liable for, and our assets are not available to satisfy, the obligations of KMP and EPB and/or their respective subsidiaries and vice versa, except as discussed in the following paragraph. Responsibility for payments of obligations reflected in our, KMP's or EPB's financial statements is a legal determination based on the entity that incurs the liability.

Effective November 1, 2012, we sold KMP's FTC Natural Gas Pipelines disposal group to Tallgrass Energy Partners, L.P. for approximately $1.8 billion (before selling costs), or $3.3 billion including our share of joint venture debt, to satisfy terms of a March 15, 2012 agreement with the U.S. FTC to divest certain of our assets in order to receive regulatory approval for our EP acquisition. KMP's FTC Natural Gas Pipelines disposal group's assets included (i) Kinder Morgan Interstate Gas Transmission natural gas pipeline system; (ii) Trailblazer natural gas pipeline system; (iii) Casper and Douglas natural gas processing operations; and (iv) 50% equity investment in the Rockies Express natural gas pipeline system. Accordingly, we (i) reclassified and excluded KMP's FTC Natural Gas Pipelines disposal group's results of operations from our results of continuing operations and reported the disposal group's results of operations separately as "Income from operations of KMP's FTC Natural Gas Pipelines disposal group and other, net of tax" within the discontinued operations section of our accompanying consolidated statements of income for all periods presented and (ii) separately reported a "Loss on sale and the remeasurement of KMP's FTC Natural Gas Pipelines disposal group to fair value, net of tax" within the discontinued operations section of our accompanying consolidated statements of income for the years ended December 31, 2013 and 2012. In addition, we did not elect to present separately the operating, investing and financing cash flows related to the disposal group in our accompanying consolidated statements of cash flows.

For more information about the divestiture of KMP's FTC Natural Gas Pipelines disposal group, see Note 3.

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 disclosure of 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 $75 million and $52 million as of December 31, 2013 and 2012, respectively is included in "Other current assets," and restricted cash of $2 million as of December 31, 2013, is included in "Deferred charges and other assets."

Accounts Receivable

The amounts reported as "Accounts receivable, net" on our accompanying consolidated balance sheets as of December 31, 2013 and 2012 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.

Inventories

Our inventories of products consist of materials and supplies, NGL, refined petroleum products 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 the lower of cost or market or index prices, per our quarterly imbalance valuation procedures. Gas imbalances represent the difference between customer nominations and actual gas receipts from, and gas deliveries to, our interconnecting pipelines and shippers under various operational balancing and shipper imbalance agreements. Natural gas imbalances are either settled in cash or made up in-kind subject to the pipelines' various tariff provisions. As of both December 31, 2013 and 2012, our gas imbalance receivables—including both trade and related party receivables—totaled $83 million and $18 million, respectively, and we included these amounts within "Other current assets" on our accompanying consolidated balance sheets. As of December 31, 2013 and 2012, our gas imbalance payables—consisting of only trade payables—totaled $34 million and $150 million, respectively, and we included these amounts within "Other current liabilities" on our accompanying consolidated balance sheets.

Property, Plant and Equipment

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for maintenance and repairs in the period incurred. As discussed below, for assets used in our oil and gas producing activities or in our unregulated bulk and liquids terminal activities, the cost of property, plant and equipment sold or retired and the related depreciation are removed from our balance sheet in the period of sale or disposition, and we record any related gains and losses from sales or retirements to income or expense accounts. For our pipeline system assets, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. We do not include retirement gain or loss in income except in the case of significant retirements or sales. Gains and losses on minor operating unit sales, excluding land, are recorded to the appropriate accumulated depreciation reserve. Generally, gains and losses for operating unit sales and land sales are booked 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.

We generally compute depreciation using the straight-line method based on estimated economic lives; however, 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. Depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates included 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. However, 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.

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.

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The acquisition cost 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 rate is determined by field.

As discussed in "—Inventories" above, we own and maintain natural gas in underground storage as part of our inventory. This component of our inventory represents the portion of gas stored in an underground storage facility generally known as working gas, and represents an estimate of the portion of gas in these facilities available for routine injection and withdrawal. In addition to this working gas, underground gas storage reservoirs contain injected gas which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow efficient operation of the facility. This gas, generally known as cushion gas, is divided into the categories of recoverable cushion gas and unrecoverable cushion gas, based on an engineering analysis of whether the gas can be economically removed from the storage facility at any point during its life. The portion of the cushion gas that is determined to be unrecoverable is considered to be a permanent part of the facility itself (thus, part of our "Property, plant and equipment, net" balance in our accompanying consolidated balance sheets), and this unrecoverable portion is depreciated over the facility's estimated useful life. The portion of the cushion gas that is determined to be recoverable is also considered a component of the facility but is not depreciated because it is expected to ultimately be recovered and sold.

Impairments

We review long-lived assets for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset 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.

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 and possible reserves. For the purpose of impairment testing, adjustments for the inclusion of risk-adjusted probable and possible reserves, as well as forward curve pricing, 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.

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, 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.

Equity method of accounting

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.

Goodwill

Goodwill represents the excess of the cost of an acquisition price over the fair value of the acquired net assets, and such amounts are reported separately on our consolidated balance sheets. As of December 31, 2013 and 2012 our total goodwill was $24,504 million and $23,632 million, respectively. Goodwill is not amortized, but instead is 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 perform our goodwill impairment test on May 31 of each year. There were no impairment charges resulting from our May 31, 2013, 2012 or 2011 impairment testing, and no event indicating an impairment has occurred subsequent to May 31, 2013.

If a significant portion of one of our business segments is disposed of (that also constitutes a business), we would allocate goodwill based on the relative fair values of the portion of the segment being disposed of and the portion of the segment remaining.

Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We recognize natural gas sales revenues and NGL sales revenue when the natural gas or NGL is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales.

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 title 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—KMP 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 expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense expenditures 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 difference between the fair value of plan assets and the plan's benefit obligation of our consolidated subsidiaries' pension and other postretirement benefit plans as either assets or liabilities on our 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 income or as a regulatory asset or liability for certain of our regulated operations, until they are amortized to be recognized as a component of benefit expense.

Noncontrolling Interests

Noncontrolling interests represents the outstanding ownership 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 represents the ownership interests in our consolidated subsidiaries' net assets held by parties other than us. It 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 us, we have applied an accounting policy that looks through its investments including its investment in KMP and EPB. 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 investment in KMP and EPB.

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, 2013, 2012 and 2011, 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 13.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of 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 measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. If the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from fair value accounting and is accounted for using traditional accrual accounting.

Furthermore, changes in our derivative contracts' fair values are recognized currently in earnings unless hedge accounting is applied. If a derivative contract meets specific accounting criteria, the contract's gains and losses are allowed to offset related results on the hedged item in our income statement, and we may formally designate the derivative contract as a hedge and document and assess the effectiveness of the contract associated with the transaction that receives hedge accounting. Only designated qualifying items that are effectively offset by changes in fair value or cash flows during the term of the hedge are eligible to use the special accounting for hedging.

Our derivative contracts that hedge our energy commodity price risks involve our normal business activities, which include the purchase and sale of natural gas, NGL and crude oil, and we may designate these derivative contracts as cash flow hedges—derivative contracts that hedge exposure to variable cash flows of forecasted transactions—and the effective portion of these derivative contracts' gain or loss is initially reported as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transactions affect earnings. The ineffective portion of the gain or loss is reported in earnings immediately.

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, 2013, the recovery period for these regulatory assets was approximately one year to forty-two years.

The following table summarizes our regulatory asset and liability balances as of December 31, 2013 and 2012 (in millions):

	December 31,	
	2013	**2012**
Current regulatory assets	$ 91	$ 62
Non-current regulatory assets	446	402
Total regulatory assets(a)	$ 537	$ 464
Current regulatory liabilities	$ 135	$ 7
Non-current regulatory liabilities	397	113
Total regulatory liabilities(b)	$ 532	$ 120

(a) Includes an $88 million increase since December 31, 2012 (net of related amortization of $5 million) associated with TGP's sale of certain natural gas facilities located offshore in the Gulf of Mexico and onshore in the state of Louisiana.

(b) During the second quarter of 2013, we began applying regulatory accounting to the Trans Mountain pipeline systems due to a newly negotiated long-term tolling agreement approved by the system's regulator that went into effect in April 2013. The primary impact of applying regulatory accounting was the reclassification of approximately $362 million of current and long-term deferred credits to regulatory liabilities. KMP expects this regulatory liability to be refunded to rate-payers over approximately the next four years. As of December 31, 2013, $113 million remains classified as a current regulatory liability.

On July 26, 2012, TGP filed an application with the FERC seeking authority to abandon by sale certain natural gas facilities located offshore in the Gulf of Mexico and onshore in the state of Louisiana, as well as a related offer of settlement that addressed the proposed rate and accounting treatment associated with the sale. The offer of settlement provided for a rate adjustment to TGP's maximum tariff rates upon the transfer of the assets and established a regulatory asset for a portion of the unrecovered net book value of the facilities to be sold. Effective September 1, 2013, following the FERC's approval of both the requested abandonment authorization and the offer of settlement, TGP sold these assets, and in 2013, TGP recognized both a $93 million increase in regulatory assets and a $36 million gain from the sale of assets.

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

For the year ended December 31, 2013, earnings per share was calculated using the two-class method. Earnings were allocated to Class P shares of common stock and to 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 do not participate in excess distributions over earnings. For the year ended December 31, 2013, the following potential weighted-average Class P common shares are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share; (i) 4 million related to unvested restricted stock awards; (ii) 401 million related to outstanding warrants to purchase our Class P shares; and (iii) 10 million related to convertible trust preferred securities.

The following table sets forth the allocation of net income available to shareholders for Class P shares and for participating securities for the year ended December 31, 2013 (in millions):

	Year Ended December 31, 2013	
Class P	$	1,187
Participating securities(a)		6
Net Income Attributable to Kinder Morgan, Inc.	$	1,193

(a) Participating securities are unvested restricted stock awards issued to management employees that contain non-forfeitable rights to dividend equivalent payments.

On December 26, 2012, the remaining series of our Class A, Class B, and Class C shares were fully-converted and as a result, only our Class P common stock was outstanding as of December 31, 2012 (see Note 10).

For the year ended December 31, 2012 and the period February 11, 2011 through December 31, 2011, earnings per share was calculated using the two-class method. Earnings were allocated to each class of common stock based on the amount of dividends paid in the current period for each class of stock 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. For the investor retained stock, the allocation of undistributed earnings or excess distributions over earnings was in direct proportion to the maximum number of Class P shares into which it could convert.

For the Class P diluted earnings per share computations, total net income attributable to Kinder Morgan, Inc. was divided by the adjusted weighted-average shares outstanding during the period, including all dilutive potential shares. This included the Class P shares into which the investor retained stock (collectively, our Class A, Class B and Class C common stocks) was convertible. The number of Class P shares on a fully-converted basis was the same before and after any conversion of our investor retained stock. Each time one Class P share was issued upon conversion of investor retained stock, the number of Class P shares went up by one, and the number of Class P shares into which the investor retained stock was convertible went down by one. Accordingly, there was no difference between Class P basic and diluted earnings per share because the conversion of Class A, Class B, and Class C shares into Class P shares did not impact the number of Class P shares on a fully-converted basis. Commencing with the acquisition of EP, dilutive potential shares also included the Class P shares issuable in connection with the warrants and the trust preferred securities (see Note 10). As no securities were convertible into Class A shares, the basic and diluted earnings per share computations for Class A shares were the same. For the year ended December 31, 2012, the following potential Class P common shares were antidilutive and, accordingly, were excluded from the determination of diluted earnings per share; (i) 451 million related to outstanding warrants to purchase our Class P shares; and (ii) 11 million related to convertible trust preferred securities.

The following tables set forth the computation of basic and diluted earnings per share from continuing operations for the year ending December 31, 2012 and the period ending February 11, 2011 through December 31, 2011 (the date of our initial public offering) (in millions, except per share amounts):

	Year ended December 31, 2012			
	Income from Continuing Operations Available to Shareholders			
	Class P	**Class A**	**Participating Securities(a)**	**Total**
Income from continuing operations				$ 1,204
Less: income from continuing operations attributable to noncontrolling interests				(696)
Income from continuing operations attributable to KMI				508
Dividends paid in the period	$ 601	$ 542	$ 41	(1,184)
Excess distributions over earnings	(344)	(331)	(1)	$ (676)
Income from continuing operations attributable to shareholders	$ 257	$ 211	$ 40	$ 508
Basic earnings per share from continuing operations				
Basic weighted-average number of shares outstanding	461	446	N/A	
Basic earnings per common share from continuing operations(b)	$ 0.56	$ 0.47	N/A	
Diluted earnings per share from continuing operations				
Income from continuing operations attributable to shareholders and assumed conversions(c)	$ 508	$ 211	N/A	
Diluted weighted-average number of shares	908	446	N/A	
Diluted earnings per common share from continuing operations(b)	$ 0.56	$ 0.47	N/A	

	February 11. 2011 through December 31, 2011			
	Income from Continuing Operations Available to Shareholders			
	Class P	Class A	Participating Securities(a)	Total
Income from continuing operations for the year ended December 31, 2011				$ 449
Plus: loss from continuing operations attributable to noncontrolling interests for the year ended December 31, 2011				112
Income from continuing operations attributable to KMI for the year ended December 31, 2011				561
Less: income from continuing operations attributable to KMI members prior to incorporation				(67)
Total net income from continuing operations attributable to shareholders				494
Dividends paid in the period	$ 87	$ 399	$ 38	(524)
Excess distributions over earnings	(5)	(25)	—	$ (30)
Income from continuing operations attributable to shareholders	$ 82	$ 374	$ 38	$ 494
Basic earnings per share from continuing operations				
Basic weighted-average number of shares outstanding(d)	118	589	N/A	
Basic earnings per common share from continuing operations(b)	$ 0.70	$ 0.64	N/A	
Diluted earnings per share from continuing operations				
Income from continuing operations attributable to shareholders and assumed conversions(c)	$ 494	$ 374	N/A	
Diluted weighted-average number of shares(d)	708	589	N/A	
Diluted earnings per common share from continuing operations(b)	$ 0.70	$ 0.64	N/A	

The following tables set forth the computation of basic and diluted earnings per share for the year ended December 31, 2012 and for the period February 11, 2011 through December 31, 2011 (in millions, except per share amounts):

	Year ended December 31, 2012			
	Net Income Available to Shareholders			
	Class P	Class A	Participating Securities(a)	Total
Net income attributable to KMI				$ 315
Dividends paid in the period	$ 601	$ 542	$ 41	(1,184)
Excess distributions over earnings	(441)	(426)	(2)	$ (869)
Net income attributable to shareholders	$ 160	$ 116	$ 39	$ 315
Basic earnings per share				
Basic weighted-average number of shares outstanding	461	446	N/A	
Basic earnings per common share(b)	$ 0.35	$ 0.26	N/A	
Diluted earnings per share				
Net income attributable to shareholders and assumed conversions(c)	$ 315	$ 116	N/A	
Diluted weighted-average number of shares	908	446	N/A	
Diluted earnings per common share(b)	$ 0.35	$ 0.26	N/A	

	February 11, 2011 through December 31, 2011			
	Net Income Available to Shareholders			
	Class P	Class A	Participating Securities(a)	Total
Net income attributable to KMI for the year ended December 31, 2011				$ 594
Less: net income attributable to KMI members prior to incorporation				(70)
Net income attributable to shareholders				524
Dividends paid in the period	$ 87	$ 399	$ 38	(524)
Excess distributions over earnings	—	—	—	$ —
Total net income attributable to shareholders	$ 87	$ 399	$ 38	$ 524
Basic earnings per share				
Basic weighted-average number of shares outstanding(d)	118	589	N/A	
Basic earnings per common share(b)	$ 0.74	$ 0.68	N/A	
Diluted earnings per share				
Net income attributable to shareholders and assumed conversions(c)	$ 524	$ 399	N/A	
Diluted weighted-average number of shares(d)	708	589	N/A	
Diluted earnings per common share(b)	$ 0.74	$ 0.68	N/A	

(a) Participating securities included Class B shares, Class C shares, and unvested restricted stock awards issued to non-senior management employees that contained rights to dividend equivalents in the case of the restricted shares. Our Class B and Class C shares were entitled to participate in our earnings, only to the extent of cash distributions made to them. As a result, no earnings in excess of dividends received were allocated to the Class B and Class C shares in our determination of basic and diluted earnings per share.

(b) The Class A shares earnings per share as compared to the Class P shares earnings per share were reduced due to the sharing of economic benefits (including dividends) amongst the Class A, B, and C shares. Class A, B and C shares owned by Richard Kinder, the sponsor investors, the original shareholders, and other management were referred to as "investor retained stock," and were convertible into a fixed number of Class P shares. In the aggregate, our investor retained stock was entitled to receive a dividend per share on a fully-converted basis equal to the dividend per share on our common stock. The conversion of shares of investor retained stock into Class P shares did not increase our total fully-converted shares outstanding, impact the aggregate dividends we paid or the dividends we paid per share on our Class P common stock.

(c) For the diluted earnings per share calculation, total net income attributable to each class of common stock was divided by the adjusted weighted-average shares outstanding during the period, including all dilutive potential shares.

(d) The weighted-average shares outstanding calculation is based on the actual days in which the shares were outstanding for the period from February 11, 2011 to December 31, 2011.

3. Acquisitions and Divestitures

Business Combinations and Acquisitions of Investments

During 2013, 2012 and 2011, we and our subsidiary, KMP, completed the following significant acquisitions, and except for the acquisition of two separate equity interests in Watco Companies, LLC (noted as (2) and (6) in the table and discussion below), we accounted for these acquisitions 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 and KMP's goodwill are both the value of the synergies created between the acquired assets and its pre-existing assets, and its expected ability to grow the business acquired by leveraging pre-existing business experience. With the exception of KMP's acquisitions of (i) KinderHawk and EagleHawk Field Services LLC and (ii) SouthTex Treaters (noted as (4) and (5), respectively, in the table and discussion below), we do not expect our recorded goodwill to be deductible for tax purposes.

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
KMI											
(1)	5/12	EP	$ 22,928	$ 7,175	$ 12,921	$ 5,718	$ 18,562	$ (13,417)	$ (4,234)	$ (3,797)	$ —
KMP											
(2)	1/11	Watco Companies, LLC (1 of 2)	50	—	—	50	—	—	—	—	—
(3)	6/11	TGS Development, L.P. Terminal Acquisition	67	—	43	31	—	—	(7)	—	—
(4)	7/11	KinderHawk and EagleHawk	835	36	642	140	94	(77)	—	—	—
(5)	11/11	SouthTex Treaters, Inc. Natural Gas Treating Assets	152	27	9	17	126	—	(27)	—	—
(6)	12/11	Watco Companies, LLC (2 of 2)	50	—	—	50	—	—	—	—	—
(7)	5/13	Copano	3,733	218	2,805	1,775	1,141	(1,252)	(233)	(17)	(704)
(8)	6/13	Goldsmith-Landreth Field Unit	280	—	298	—	—	—	(18)	—	—

(1) EP

Effective on May 25, 2012, we acquired all of the outstanding shares of EP for an aggregate consideration of approximately $22.9 billion (excluding assumed debt, but including payments of $87 million for share based awards expensed in the post-combination period). In total, EP shareholders received (i) $11.6 billion in cash, (ii) 330 million KMI Class P shares with a fair value of $10.6 billion (based on the $32.11 closing market price of a Class P share on May 24, 2012) and (iii) 505 million KMI warrants with a fair value of $863 million (based on a fair value of $1.71 per warrant as of May 24, 2012). The warrants have an exercise price of $40 per share and a 5-year term.

During the second quarter of 2013, management completed its purchase accounting valuation estimates and, as a result, retrospectively adjusted the valuations of certain liabilities with a corresponding increase to goodwill as of the acquisition date. The retrospective adjustments amounted to approximately $60 million and primarily related to revisions of estimates related to certain environmental obligations, sales and use tax liabilities, and deferred income taxes.

The asset amount assigned to “Deferred charges & other” in the table above includes $4,211 million assigned to “Investments.” The “Other liabilities” assumed and shown in the table above includes $1,463 million assigned to “Total current liabilities.” The “Noncontrolling interests” assumed in the EP acquisition represents the fair value of noncontrolling interests associated with EP’s investment in EPB and was based on the 117 million EPB common units outstanding to the public as of May 24, 2012 valued at EPB’s May 24, 2012 closing price of $32.37 per common unit.

On May 24, 2012, EP sold its subsidiary, EP Energy LLC, which consisted of EP’s exploration and production business for $7.2 billion. Accordingly, the assets and liabilities of EP Energy LLC are not included in the purchase price allocation table above and the net sale proceeds were used to pay off the holders of EP Energy LLC’s $961 million long-term debt, and the remaining $6.2 billion (included in “Current assets” in the table above) was used to pay for a portion of the $11.6 billion cash portion of the purchase price. EP’s net operating loss carryforwards are expected to significantly offset the cash taxes associated with the sale of EP Energy LLC.

During the year 2012, we incurred $463 million, net of legal recoveries, of pre-tax expenses associated with the EP acquisition, and EP Energy sale, including (i) $160 million in employee severance, retention and bonus costs; (ii) $87 million of accelerated EP stock based compensation allocated to the post-combination period under applicable GAAP rules; (iii) $37 million in advisory fees; (iv) $68 million for legal fees and reserves, net of legal recoveries; (v) a $108 million write-off (due to debt repayments) or amortization of capitalized financing fees associated with the EP acquisition financing; and less (vi) a $29 million benefit associated with pension income.

Together, EP and its subsidiary EPB offered natural gas transmission services to a range of customers, including natural gas producers, marketers and end-users, as well as other natural gas transmission, distribution and electric generation companies. The pipelines group of EP and EPB were the nation’s largest interstate natural gas pipeline franchise, transporting natural gas through interstate natural gas pipelines that connect the nation’s principal supply regions to its major consuming regions (the Gulf Coast, California, the northeast, the southwest and the southeast). The pipelines business also included storage and LNG terminaling facilities. Most of the acquired assets are included in the Natural Gas Pipelines business segment.

(2) Watco Companies, LLC (1 of 2)

On January 3, 2011, KMP purchased 50,000 Class A preferred shares of Watco Companies, LLC for $50 million in cash in a private transaction. In connection with its purchase of these preferred shares, the most senior equity security of Watco, KMP entered into a limited liability company agreement with Watco that provides KMP certain priority and participating cash distribution and liquidation rights. Pursuant to the agreement, KMP receives priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and it participates partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide KMP certain approval rights, including the right to appoint one of the members to Watco’s Board of Managers. On December 28, 2011, KMP made an additional $50 million investment in Watco, as described below in “—(6) Watco Companies, LLC (2 of 2).”

Watco Companies, LLC is the largest privately held short line railroad company in the U.S., operating 22 short line railroads on approximately 3,500 miles of leased and owned track. KMP’s investment provided capital to Watco for further expansion of specific projects and complemented KMP’s existing terminal network. It also provides KMP’s customers more transportation services for many of the commodities that it currently handles, and offers it the opportunity to share in additional growth opportunities through new projects. As of December 31, 2013, KMP’s net equity investment in Watco totaled $103 million and is within “Investments” on our accompanying consolidated balance sheet. KMP accounts for its investment under the equity method of accounting, and we include it in the Terminals—KMP business segment.

(3) TGS Development, L.P. Terminal Acquisition

On June 10, 2011, KMP acquired a newly constructed petroleum coke terminal located in Port Arthur, Texas from TGS Development, L.P. (TGSD) for an aggregate consideration of $74 million, consisting of $43 million in cash, $24 million in common units, and an obligation to pay additional consideration of $7 million. In March 2012, KMP settled the $7 million liability by issuing additional common units to TGSD (KMP issued 87,162 common units and determined each unit’s value based on the $83.87 closing market price of the common units on the NYSE on the March 14, 2012 issuance date).

All of the acquired assets are located in Port Arthur, Texas, and include long-term contracts to provide petroleum coke handling and cutting services to improve the refining of heavy crude oil at Total Petrochemicals USA Inc.’s Port Arthur refinery. The acquisition complemented KMP’s existing Gulf Coast bulk terminal facilities and expanded its pre-existing petroleum coke handling operations. All of the acquired assets are included as part of the Terminals—KMP business segment.

(4) KinderHawk and EagleHawk

Effective July 1, 2011, KMP acquired from Petrohawk Energy Corporation (Petrohawk, now a subsidiary of BHP Billiton as discussed below) both the remaining 50% equity ownership interest in KinderHawk that it did not already own and a 25% equity ownership interest in EagleHawk, Petrohawk's natural gas gathering and treating business located in the Eagle Ford shale formation in South Texas for an aggregate consideration of $912 million, consisting of $835 million in cash and assumed debt of $77 million (representing 50% of KinderHawk's borrowings under its bank credit facility as of July 1, 2011). KMP then repaid the outstanding $154 million of borrowings and following this repayment, KinderHawk had no outstanding debt. KMP also terminated the revolving bank credit facility at the time of such repayment. All of the acquired operations are included in the Natural Gas Pipelines business segment.

Following this acquisition of the remaining ownership interest on July 1, 2011, KMP changed its method of accounting from the equity method to full consolidation, and due to the fact that KMP acquired a controlling financial interest in KinderHawk, KMP remeasured its previous 50% equity investment in KinderHawk to its fair value. KMP recognized a $167 million non-cash loss as a result of this remeasurement. The loss amount represented the excess of the carrying value of KMP's investment ($910 million as of July 1, 2011) over its fair value ($743 million), and we reported this loss separately within the "Other Income (Expense)" section in our accompanying consolidated statement of income for the year ended December 31, 2011. Additionally, on August 25, 2011, mining and oil company BHP Billiton completed its previously announced acquisition of Petrohawk through a short-form merger under Delaware law. The merger was closed with Petrohawk being the surviving corporation as a wholly owned subsidiary of BHP Billiton. The acquisition did not affect the terms of KMP's contracts with Petrohawk.

(5) SouthTex Treaters, Inc. Asset Acquisition

On November 30, 2011, KMP acquired a manufacturing complex and certain natural gas treating assets from SouthTex Treaters, Inc. for an aggregate consideration of $179 million, consisting of $152 million in cash and assumed liabilities of $27 million. SouthTex Treaters, Inc. is a leading manufacturer, designer and fabricator of natural gas treating plants that are used to remove impurities (CO_2 and hydrogen sulfide) from natural gas before it is delivered into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. The acquisition complemented and expanded KMP's existing natural gas treating business, and all of the acquired operations are included in the Natural Gas Pipelines business segment.

(6) Watco Companies, LLC (2 of 2)

On December 28, 2011, KMP purchased an additional 50,000 Class A preferred shares of Watco Companies, LLC for $50 million in cash in a private transaction. The priority and participating cash distribution and liquidation rights associated with these shares are similar to the rights associated with the 50,000 Class A preferred shares KMP acquired on January 3, 2011—KMP receives priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and participates partially in additional profit distributions at a rate equal to 0.5%.

(7) Copano

Effective May 1, 2013, KMP 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. KMP issued 43,371,210 of its common units valued at $3,733 million as consideration for the Copano acquisition (based on the $86.08 closing market price of a common unit on the NYSE on the May 1, 2013 issuance date).

Also, due to the fact that KMP's acquisition included the remaining 50% interest in Eagle Ford Gathering LLC that it did not already own, KMP remeasured its existing 50% equity investment in Eagle Ford to its fair value as of the acquisition date. As a result of this remeasurement, KMP recognized a $558 million non-cash gain, which represented the excess of the investment's fair value ($704 million) over the carrying value as of May 1, 2013 ($146 million). We reported this gain separately within the "Other Income (Expense)" section in our accompanying consolidated statement of income for the year ended December 31, 2013.

The table above reflects the adjusted preliminary purchase price allocation as of December 31, 2013. Deferred charges & other includes $1,375 million assigned to "Other intangibles, net" and $387 million assigned to "Investments." The intangible amount represents the fair value of acquired customer contracts and agreements, and we are currently amortizing these intangible assets over an estimated remaining useful life of 25 years. The investment amount represents an aggregate of seven separate investments, each accounted for under the equity method of accounting. KMP's evaluation of the assigned fair values is ongoing and subject to adjustment.

Our accounting policy is to apply 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. As a result of the goodwill recorded by KMP for its Copano acquisition, KMI's deferred tax liability and goodwill were increased by $260 million for the portion of its outside basis difference associated with KMP's underlying goodwill.

Copano provides comprehensive services to natural gas producers, including natural gas gathering, processing, treating and NGL fractionation. Copano owns an interest in or operates approximately 6,900 miles of pipelines with 2.7 Bcf/d of natural gas transportation capacity, and also owns nine natural gas processing plants with more than 1 Bcf/d of natural gas processing capacity and 315 MMcf/d of natural gas treating capacity. Its operations are located primarily in Texas, Oklahoma and Wyoming. Most of the acquired assets are included in the Natural Gas Pipelines business segment.

(8) Goldsmith Landreth Field Unit

On June 1, 2013, KMP 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 of December 31, 2013, the field was producing approximately 1,230 Bbl/d of oil, and as part of the transaction, KMP obtained a long-term supply contract for up to 150 MMcf/d of CO_2. The acquisition complemented KMP's existing oil and gas producing assets in the Permian Basin, and we included the acquired assets as part of the CO_2—KMP business segment. Our evaluation of the assigned fair values is ongoing and subject to adjustment.

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the years ended December 31, 2013 and 2012, assumes that the EP, Copano and the Goldsmith Landreth field unit acquisitions had occurred as of January 1, 2012. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if these acquisitions had been completed as of January 1, 2012 or the results that will be attained in the future. Amounts presented below are in millions, except for the per share amounts:

	Pro Forma Year Ended December 31, 2013	2012
	(Unaudited)	
Revenues	$ 14,775	$ 13,035
Income from continuing operations	2,655	866
Income from discontinued operations, net of tax	(4)	1,291
Net income	2,651	2,157
Net income attributable to noncontrolling interests	(1,486)	(153)
Net income attributable to Kinder Morgan, Inc.	1,165	2,004
Diluted earnings per common share		
Class P shares	$ 1.12	$ 1.93
Class A shares		$ 1.84

Acquisition Subsequent to December 31, 2013

Effective January 17, 2014, KMP acquired American Petroleum Tankers (APT) and State Class Tankers (SCT) from affiliates of The Blackstone Group and Cerberus Capital Management for an aggregate consideration of approximately $962 million in cash (pending final true-ups for both acquired working capital balances and capital spending prior to the closing date). KMP funded this transaction with borrowings made under its commercial paper program which is supported by a short-term liquidity facility dated January 17, 2014 (see Note 8 "Debt—Credit Facilities and Restrictive Covenants—KMP —

Subsequent Event”). Additionally, KMGP, as KMP’s general partner, has agreed to waive incentive distribution amounts of $13 million for 2014, $19 million for 2015 and $6 million for 2016 to facilitate the transaction.

APT and SCT are engaged 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. APT’s 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. Navy. The vessels’ time charters have an average remaining term of approximately four years, with renewal options to extend the initial terms by an average of two years. APT’s vessels are operated by Crowley Maritime Corporation.

SCT has commissioned the construction of four medium range Jones Act qualified product tankers, each with 330 MBbl of cargo capacity. The SCT vessels are scheduled to be delivered in 2015 and 2016 and are being constructed by General Dynamics’ NASSCO shipyard. KMP expects to invest approximately $214 million to complete the construction of the vessels. Upon delivery, the SCT vessels will be operated pursuant to long-term time charters with a major integrated oil company. Each of the time charters has an initial term of five years, with renewal options to extend the initial term by up to three years. The acquisition of APT and SCT complements and extends KMP’s existing crude oil and refined products transportation business, and all of the acquired assets are included in the Terminals—KMP business segment.

Drop-down of EP Assets to KMP

August 2012

Effective August 1, 2012, KMP acquired a 100% ownership interest in TGP and an initial 50% ownership interest in EPNG from us for an aggregate consideration of approximately $6.2 billion (including a proportional share of assumed debt borrowings as of August 1, 2012). The consideration that we received from KMP consisted of (i) $3.5 billion in cash; (ii)4,667,575 of KMP’s common units (valued at $0.4 billion based on KMP’s $81.52 closing market price of the common units on the NYSE on the August 1, 2012 issuance date); and (iii) $2.3 billion in assumed debt (consisting of the combined carrying value of 100% of TGP’s debt borrowings and 50% of EPNG’s debt borrowings as of August 1, 2012, excluding any debt fair value adjustments). We used the proceeds from the drop-down transaction to (i) pay down $2.3 billion on our 3-year term loan facility; (ii) pay off and terminate our 364-day bridge facility; and (iii) pay off an $839 million senior note which matured on September 1, 2012.

March 2013

Effective March 1, 2013, KMP acquired from us the remaining 50% ownership interest it did not already own in both EPNG and the EP midstream assets (see “—KMP Previously Held Investment in El Paso Midstream Investment Company, LLC” following) for an aggregate consideration of approximately $1.7 billion (including a proportional 50% share of assumed debt borrowings as of March 1, 2013). The consideration that we received from KMP consisted of (i) $994 million in cash (including $6 million in the second quarter of 2013 to settle the final working capital adjustment); (ii) 1,249,452 common units (valued at $108 million based on the $86.72 closing market price of KMP’s common unit on the NYSE on the March 1, 2013 issuance date); and (iii) $557 million in assumed debt (consisting of 50% of the outstanding principal amount of EPNG’s debt borrowings as of March 1, 2013, excluding any debt fair value adjustments). We used the proceeds from the March 1, 2013 drop-down transaction to (i) pay down $947 million of our senior secured term loan facility; and (ii) reduce borrowings under our credit facility.

In this report, we refer to these acquisitions of assets by KMP from us as the drop-down transactions and the combined group of assets acquired by KMP from us as the drop-down asset groups. The terms of the drop-down transactions were approved on our behalf by the independent members of our board of directors and on KMP’s behalf by the audit committees and the boards of directors of both KMGP, as KMP’s general partner, and KMR, in its capacity as the delegate of KMGP, following the receipt by our independent directors and by the audit committees of KMGP and KMR of separate fairness opinions from different independent financial advisors.

The drop-down transactions were accounted for as transfers of net assets between entities under common control. Specifically, we have retrospectively adjusted our consolidated financial statements to reflect the recognition by KMP of the acquired assets and assumed liabilities at our carrying value, including our EP purchase accounting adjustments as of May 25, 2012.

KMP Previously Held Investment in El Paso Midstream Investment Company, LLC

Effective June 1, 2012, KMP acquired from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. (together with its affiliates, referred to as KKR) a 50% ownership interest in El Paso Midstream Investment Company, LLC (EP Midstream), a joint venture that owns (i) the Altamont natural gas gathering, processing and treating assets located in the Uinta Basin in Utah and (ii) the Camino Real natural gas and oil gathering system located in the Eagle Ford shale formation in South Texas, collectively referred to in this report as the EP midstream assets. KMP acquired its initial 50% interest for an aggregate consideration of $289 million in common units (KMP issued 3,792,461 common units and determined each unit's value based on KMP's $76.23 closing market price of the common units on the NYSE on the June 4, 2012 issuance date).

We, through our EP acquisition, owned the remaining 50% of the EP Midstream assets, and as a result we consolidated EP Midstream in the accompanying consolidated financial statements effective June 1, 2012. The operating results of the EP midstream assets are included in the Natural Gas Pipelines business segment. No gain or loss on the previously held equity investment was recognized as the fair value of the equity investment acquired through our EP acquisition was determined to equal the $289 million purchase price paid by KMP for its 50% interest. As such, the fair value of 100% of EP Midstream was determined to be $578 million.

We measured the identifiable intangible assets acquired at fair value on the acquisition date, and as a result, we recognized $50 million in "Deferred charges and other assets," representing the fair value of separate and identifiable relationships with existing customers. We estimated the remaining useful life of these existing customer relationships to be approximately 10 years. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, we recognized $248 million of "Goodwill." We believe the primary item that generated the goodwill is our ability to grow the business by leveraging our pre-existing natural gas operations, and we believe that this value contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities. This goodwill is not deductible for tax purposes.

Income Tax Impact of the Drop-Down of EP Assets to KMP

As discussed above, we accounted for the acquisition of EP as a business combination and for the subsequent March 2013 and August 2012 drop-down transactions as transfers of net assets between entities under common control. For income tax purposes, the March 2013 drop-down transaction was treated as a contribution and the August 2012 drop-down transaction was treated as a partial sale, and a partial contribution.

Our accounting policy is to apply 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. As a result of the drop-down transactions, a deferred tax liability arose related to the portion of the outside basis difference associated with the underlying goodwill that was contributed to KMP by us. However, since the drop-downs were transactions between entities under common control, we recognized an offsetting deferred charge of $448 million for the August 2012 and $53 million for the March 2013 drop-down transactions. These balances will be amortized to income tax expense over the remaining useful lives of the transferred assets of approximately 25 years Similar to the impact described above, KMP's acquisition of a 50% ownership interest in the EP Midstream joint venture, also generated the recognition of a deferred charge and corresponding deferred tax liability and is included in the amount above. For the year ended December 31, 2013 and the period subsequent to the August 2012 drop-down through December 31, 2012, total income tax expense related to the amortization of the deferred charges was approximately $20 million and $7 million, respectively.

Divestitures

KMP's FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

As described above in Note 2, following our March 2012 agreement with the FTC, we began accounting for KMP's FTC Natural Gas Pipelines disposal group as discontinued operations (prior to KMI's sale announcement, we included the disposal group in the Natural Gas Pipelines business segment). Effective November 1, 2012, we then sold KMP's FTC Natural Gas Pipelines disposal group to Tallgrass Energy Partners, LP (now known as Tallgrass Development, LP) (Tallgrass), and KMP received proceeds of $1,791 million (before cash selling expenses). In November 2012, we also paid selling expenses of $78 million (consisting of certain required tax payments to joint venture partners).

Additionally, during 2012, KMP remeasured the disposal group's net assets to reflect its assessment of fair value as a result of the FTC mandated sale requirement, and as a result of this remeasurement of net assets to fair value and the sale of net assets, we recognized a combined $937 million loss. We reported this loss amount separately as "Loss on sale and the remeasurement of KMP’s FTC Natural Gas Pipelines disposal group to fair value, net of tax” within the discontinued operations section of our accompanying consolidated statement of income for the year ended December 31, 2012. We reported the proceeds received from the sale separately as “Proceeds from disposal of discontinued operations” within the investing section of our accompanying consolidated statement of cash flows for the year ended December 31, 2012.

In 2013, KMP and Tallgrass trued up the final consideration for the sale of KMP’s FTC Natural Gas Pipelines disposal group and based both on this true up and certain incremental selling expenses paid in 2013, we recognized an additional $4 million loss. We reported this loss amount separately as “Loss on sale and the remeasurement of KMP’s FTC Natural Gas Pipelines disposal group to fair value, net of tax” within the discontinued operations section of our accompanying consolidated statement of income for the year ended December 31, 2013, and except for this loss amount, no other financial results from the operations of KMP’s FTC Natural Gas Pipelines disposal group were recorded in 2013.

Summarized financial information for KMP’s FTC Natural Gas Pipelines disposal group is as follows (in millions):

	Year Ended December 31,	
	2012(a)	2011
Operating revenues	$ 227	$ 322
Operating expenses	(131)	(183)
Depreciation and amortization	(7)	(24)
Other expense	(1)	—
Earnings from equity investments	70	87
Interest income and Other, net	2	2
Income tax expense	—	(2)
Income from operations of KMP’s FTC Natural Gas Pipelines disposal group	$ 160	$ 202

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(a) 2012 amounts represent financial information for the ten month period ended October 31, 2012. We sold KMP’s FTC Natural Gas Pipelines disposal group effective November 1, 2012.

Express Pipeline System

Effective March 14, 2013, KMP sold both its one-third equity ownership interest in the Express pipeline system and its subordinated debenture investment in Express to Spectra Energy Corp. KMP received net cash proceeds of $402 million (after paying both a final working capital settlement and certain transaction related selling expenses), and we reported the net cash proceeds received from the sale separately as “Proceeds from sales of assets and investments” within the investing section of our accompanying consolidated statement of cash flows. For the year ended December 31, 2013, we recognized a combined $224 million pre-tax gain with respect to this sale, and we reported this gain amount separately as “Gain on sale of investments in Express pipeline system” on our accompanying consolidated statement of income. We also recorded an income tax expense of $84 million related to this gain on sale, and we included this expense within “Income Tax Expense.”

As of the date of sale, KMP’s equity investment in Express totaled $67 million and its note receivable due from Express totaled $110 million. Prior to KMP’s sale, we (i) accounted for KMP’s equity investment under the equity method of accounting; (ii) accounted for KMP’s debt investment under the historical amortized cost method of accounting; and (iii) included the financial results of the Express pipeline system within the Kinder Morgan Canada—KMP business segment. As of December 31, 2012, KMP’s equity and debt investments in Express totaled $65 million and $114 million, respectively, and we included the combined $179 million amount within “Assets held for sale” on our accompanying consolidated balance sheet.

BOSTCO

Effective December 1, 2012, TransMontaigne exercised its previously announced option to acquire up to 50% of KMP’s Class A member interest in BOSTCO, KMP’s previously announced oil terminal joint venture located on the Houston Ship Channel. On this date, TransMontaigne acquired a 42.5% Class A member interest in BOSTCO from KMP for an aggregate consideration of $79 million, and following this acquisition, KMP now owns a 55% Class A member interest in BOSTCO (KMP sold a 2.5% Class A member interest in BOSTCO to a third party on January 1, 2012 for an aggregate consideration of $1 million). Because KMP retained a controlling financial interest in BOSTCO, we continued to account for KMP’s investment under the full consolidation method and we accounted for this change in KMP’s ownership interest as an equity transaction.

TGP's Sale of Production Area Facilities

On September 1, 2013, TGP sold certain natural gas facilities located offshore in the Gulf of Mexico and onshore in the state of Louisiana for an aggregate consideration of $32 million in cash. TGP's net assets sold in this transaction (including assets identified as "held for sale") totaled $89 million, and as a result of the sale, TGP recognized both a $93 million increase in regulatory assets pursuant to a FERC order, and a $36 million gain from the sale of assets. We included the cash proceeds received from the sale in 2013 within "Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs" within the investing section of our accompanying consolidated statement of cash flows for the year ended December 31, 2013, and we included the gain amount within "Other Income (Expense)" on our accompanying consolidated statement of income for the year ended December 31, 2013.

BBPP Holdings Ltda

As of December 31, 2012, we owned a 2% interest in Gas Transboliviano S.A., and a 33 1/3% interest in BBPP Holdings Ltda which we acquired as a part of the May 25, 2012 EP acquisition. BBPP Holdings Ltda owned a 29% interest in Transportadora Brasileira Gasoduto Bolivia-Brasil S.A. which, together with Gas Transboliviano S.A., owned the Bolivia to Brazil Pipeline. On January 18, 2013, we completed the sale of our equity interests in the Bolivia to Brazil Pipeline for $88 million. As of December 31, 2012, our $88 million equity interests in the Bolivia to Brazil Pipeline was included within "Assets held for sale" on our accompanying consolidated balance sheet.

4. Income Taxes

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

	Year Ended December 31,		
	2013	2012	2011
U.S.	$ 3,107	$ 1,246	$ 731
Foreign	331	97	79
Total Income from Continuing Operations Before Income Taxes	$ 3,438	$ 1,343	$ 810

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,		
	2013	2012	2011
Current tax expense			
Federal	$ 57	$ 48	$ 241
State	36	34	33
Foreign	9	10	3
Total	102	92	277
Deferred tax expense			
Federal	612	49	64
State	—	4	(1)
Foreign	28	(6)	21
Total	640	47	84
Total tax provision	$ 742	$ 139	$ 361

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,					
	2013		2012		2011	
Federal income tax	$ 1,203	35.0 %	$ 470	35.0 %	$ 284	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	(21)	(0.6)%	20	1.5 %	(1)	(0.1)%
Taxes on foreign earnings	112	3.3 %	(6)	(0.5)%	24	3.0 %
Net effects of consolidating KMP's and EPB's U.S. income tax provision	(488)	(14.2)%	(288)	(21.5)%	34	4.2 %
State income tax, net of federal benefit	45	1.3 %	21	1.6 %	26	3.2 %
Dividend received deduction	(54)	(1.6)%	(32)	(2.4)%	(10)	(1.2)%
Adjustments to uncertain tax positions	(87)	(2.5)%	(72)	(5.3)%	(9)	(1.1)%
Acquisition costs	—	— %	18	1.3 %	—	— %
Other	32	0.9 %	8	0.6 %	13	1.6 %
Total	$ 742	21.6 %	$ 139	10.3 %	$ 361	44.6 %

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

	December 31,	
	2013	2012
Deferred tax assets		
Employee benefits	$ 238	$ 360
Book accruals	136	91
Net operating loss, capital loss, tax credits carryforwards (net of valuation allowance)	578	1,017
Derivative instruments	33	84
Interest rate and currency swaps	35	37
Debt fair value adjustment	112	155
Other	43	86
Total deferred tax assets	1,175	1,830
Deferred tax liabilities		
Property, plant and equipment	351	328
Investments	4,888	5,008
Book accruals	10	22
Other	10	4
Total deferred tax liabilities	5,259	5,362
Net deferred tax liabilities	$ 4,084	$ 3,532
Current deferred tax asset	$ (567)	$ (539)
Non-current deferred tax liability	4,651	4,071
Net deferred tax liabilities	$ 4,084	$ 3,532

Deferred Tax Assets and Valuation Allowances: As a result of our EP acquisition, we have deferred tax assets of $354 million related to net operating loss carryovers; alternative minimum and foreign tax credits of $308 million; and valuation allowances related to deferred tax assets of $95 million at December 31, 2013. In 2013, we also recorded an $11 million deferred tax asset related to the capital loss from our sale of the Pakistan power plant. No valuation allowance has been recorded as we fully expect to utilize this capital loss. As of December 31, 2012, the deferred tax asset related to net operating loss carryovers was $823 million, alternative minimum, general business, and foreign tax credits were $298 million, and valuation allowances related to the deferred tax assets were $104 million.

Expiration Periods for Deferred Tax Assets: As of December 31, 2013, we have U.S. federal net operating loss carryforwards of $613 million, which will expire from 2017 - 2031; state losses of $1.4 billion which will expire from 2014 - 2032; and foreign losses of $191 million, of which approximately $140 million carries over indefinitely and $51 million expires from 2028 - 2032. We also have $297 million of federal alternative minimum tax credits which do not expire; and approximately $11 million of foreign tax credits, the majority of which will expire from 2015 - 2023. 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,		
	2013	2012	2011
Balance at beginning of period	$ 269	$ 57	$ 53
Uncertain tax positions of EP	4	289	—
Subtotal	273	346	53
Additions based on current year tax positions	11	11	11
Additions based on prior year tax positions	26	1	2
Reductions based on settlements with taxing authority	(86)	(55)	—
Reductions due to lapse in statute of limitations	(15)	(34)	(9)
Balance at end of period	$ 209	$ 269	$ 57

Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense, and as of December 31, 2013, we had $29 million of accrued interest and $2 million in accrued penalties. As of December 31, 2012, we had $28 million of accrued interest and $2 million in accrued penalties. As of December 31, 2011, we had $5 million of accrued interest and $1 million of accrued penalties. All of the $209 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 $2 million during the next year to approximately $207 million.

We are subject to taxation, and have tax years open to examination for the periods 2008-2013 in the U.S., 1999-2013 in various states and 2004-2013 in various foreign jurisdictions.

5. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2013 and 2012, our property, plant and equipment consisted of the following (in millions):

	December 31,	
	2013	2012
Natural gas, liquids, crude oil and CO_2 pipelines	$ 17,399	$ 14,649
Natural gas, liquids, CO_2, and terminals station equipment	17,960	15,309
Natural gas, liquids (including linefill), and transmix processing	259	358
Other	3,656	3,319
Accumulated depreciation, depletion and amortization	(6,757)	(5,278)
	32,517	28,357
Land and land right-of-way	1,158	1,143
Construction work in process	2,172	1,496
Property, plant and equipment, net	$ 35,847	$ 30,996

As of December 31, 2013 and 2012, we included regulated property, plant and equipment amounts of $14,957 million and $14,937 million, respectively, within "Property, plant and equipment, net" on our accompanying consolidated balance sheets. These regulated amounts constituted 42% and 48%, respectively, of our total property, plant and equipment amounts at each reporting date. Depreciation, depletion, and amortization expense charged against property, plant and equipment was $1,663 million, $1,324 million, and $1,022 million, for the year ended December 31, 2013, 2012, and 2011, respectively.

Asset Retirement Obligations

As of December 31, 2013 and 2012, we recognized asset retirement obligations in the aggregate amount of $204 million and $175 million, respectively. The majority of our asset retirement obligations are associated with the CO_2—KMP business segment, where KMP is required to plug and abandon oil and gas wells that have been removed from service and to remove its surface wellhead equipment and compressors. We included $25 million and $31 million of asset retirement obligations as of December 31, 2013 and 2012, respectively, within "Other current liabilities" in our accompanying consolidated balance sheets. The remaining amounts are included within "Other long-term liabilities and deferred credits" at each reporting date.

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.

6. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and which we account for under the equity method of accounting. As of December 31, 2013 and 2012 our investments consisted of the following (in millions):

	December 31,	
	2013	2012
Citrus Corporation	$ 1,875	$ 1,966
Ruby Pipeline Holding Company, L.L.C.	1,153	1,185
Midcontinent Express Pipeline LLC	602	633
Gulf LNG Holdings Group, LLC	578	596
Plantation Pipe Line Company	307	313
EagleHawk	272	208
Red Cedar Gathering Company	176	172
Fort Union Gas Gathering L.L.C.	161	—
Double Eagle Pipeline LLC	144	—
Fayetteville Express Pipeline LLC	144	159
Parkway Pipeline LLC	131	58
Watco Companies, LLC	103	103
Cortez Pipeline Company	12	11
Eagle Ford		151
NGPL Holdco LLC	—	68
All others	285	173
Total equity investments	5,943	5,796
Bond investments	8	8
Total investments	$ 5,951	$ 5,804

The overall change in the carrying amount of our equity investments, including those of KMP, since December 31, 2012, related primarily to the increases and decreases associated with KMP's May 1, 2013 Copano acquisition. As part of this acquisition, KMP acquired an approximate 37% equity ownership interest in Fort Union Gas Gathering L.L.C., a 50% equity ownership interest in Double Eagle Pipeline LLC and the remaining 50% equity ownership interest in Eagle Ford that KMP did not already own (KMP exchanged its status as an owner of an equity investment in Eagle Ford for a full controlling financial interest, and KMP began accounting for its investment under the full consolidation method).

As shown in the table above, our remaining significant equity investments, including those of KMP (excluding the three investments described above), as of December 31, 2013 consisted of the following:

- Citrus Corporation—We operate and 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. The remaining 50% interest is owned by Energy Transfer Partners L.P.;
- 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 Global Infrastructure Partners as convertible preferred interests;
- Midcontinent Express Pipeline LLC—KMP operates and owns 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 Regency Energy 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 the subsidiaries of GE Financial Services;

- Plantation—KMP operates and owns 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 participating rights; therefore, KMP does not control Plantation, and it accounts for its investment under the equity method;
- BHP Billiton Petroleum (Eagle Ford Gathering) LLC, f/k/a EagleHawk Field Services LLC and referred to in this report as EagleHawk—KMP owns a 25% interest in EagleHawk, the sole owner of a natural gas gathering system serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton operates EagleHawk and owns the remaining 75% ownership interest;
- Red Cedar Gathering Company—KMP owns a 49% interest in the Red Cedar, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The remaining 51% interest is owned by the Southern Ute Indian Tribe;
- Fayetteville Express Pipeline LLC —KMP owns a 50% interest in Fayetteville Express Pipeline LLC, 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 Fayetteville Express Pipeline LLC;
- Parkway Pipeline LLC —KMP operates and owns a 50% interest in Parkway, the sole owner of the Parkway Pipeline refined petroleum products pipeline system. Valero Energy Corp. owns the remaining 50% interest;
- Watco Companies, LLC—KMP holds a preferred equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. KMP owns 100,000 Class A preferred shares and pursuant to the terms of its investment, it receives priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and participates partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide KMP certain approval rights, including the right to appoint one of the members to Watco's Board of Managers;
- Cortez Pipeline Company—KMP operates and owns 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; and
- NGPL Holdco LLC— KMI operates and owns a 20% interest in NGPL Holdco LLC, the owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system.

  During 2012 and 2013, continued deteriorating natural gas market conditions characterized by excess gas supply, low commodity prices, reduced basis spreads and low volatility have negatively impacted NGPL's operating results and its cash flows. We also determined that these market conditions would likely not improve in the near future. Therefore, these events caused us to evaluate the carrying value of our investment utilizing market conditions and have resulted in us recording impairments on our investment in NGPL Holdco LLC in 2012 and 2013. We recognized $200 million of pre-tax, non-cash impairment charges in 2012, and in 2013, we recognized $65 million of pre-tax, non-cash impairment charges writing down our remaining investment to its estimated fair value of zero.

  Both 2013 and 2012 non-cash impairment charges are included in the caption "Earnings from equity investments" in our accompanying consolidated statements of income.

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

	Year Ended December 31,		
	2013	2012	2011
Citrus Corporation(a)	$ 84	$ 53	$ —
Fayetteville Express Pipeline LLC	55	55	24
Gulf LNG Holdings Group, LLC(a)	47	22	—
Midcontinent Express Pipeline LLC	40	42	43
Plantation Pipe Line Company	35	32	28
Red Cedar Gathering Company	31	32	32
Cortez Pipeline Company	24	25	24
Eagle Ford(b)	14	34	11
Watco Companies, LLC	13	13	6
Fort Union Gas Gathering L.L.C.	11	—	—
EagleHawk	9	11	3
Parkway Pipeline LLC	1	—	—
Double Eagle Pipeline LLC	1	—	—
KinderHawk(c)	—	—	22
Ruby Pipeline Holding Company, L.L.C.(a)	(6)	(5)	—
NGPL Holdco LLC(d)	(66)	(198)	19
All others	34	37	14
Total	$ 327	$ 153	$ 226
Amortization of excess costs	$ (39)	$ (23)	$ (7)

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(a) 2012 amounts are for the period from May 25, 2012 through December 31, 2012.

(b) Effective May 1, 2013, KMP acquired the remaining 50% equity ownership interest in Eagle Ford that KMP did not already own and KMP changed its method of accounting from the equity method to full consolidation.

(c) Effective July 1, 2011, KMP acquired the remaining 50% equity ownership interest in KinderHawk that KMP did not already own and KMP changed its method of accounting from the equity method to full consolidation.

(d) 2013 and 2012 amounts include non-cash investment impairment charges, which we recorded in the amount of $65 million and $200 million (pre-tax), respectively, as discussed above.

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):

Income Statement	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 3,615	$ 3,681	$ 3,145
Costs and expenses	2,803	3,194	3,287
Net income (loss)	$ 812	$ 487	$ (142)

Balance Sheet	December 31,	
	2013	2012
Current assets	$ 950	$ 917
Non-current assets	20,782	21,308
Current liabilities	1,451	1,538
Non-current liabilities	11,351	11,401
Partners'/owners' equity	8,930	9,286

7. Goodwill and Other Intangibles

Goodwill and Excess Investment Cost

We record the excess of the cost of an acquisition price over the fair value of acquired net assets as an asset on our balance sheet. This amount is referred to and reported separately as "Goodwill" in our accompanying consolidated balance sheets. 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. During the quarter ended June 30, 2013, we created the Natural Gas Pipelines Non-Regulated reporting unit to include the non-regulated businesses KMP acquired from Copano on May 1, 2013 as well as other non-regulated businesses that were historically part of the former Natural Gas Pipelines reporting unit (now the Natural Gas Pipelines Regulated reporting unit). We then allocated goodwill between these two reporting units based on the relative fair values of the reporting units.

There were no impairment charges resulting from our May 31, 2013 impairment testing, and no event indicating an impairment has occurred subsequent to that date. We determined the fair value of each reporting unit as of May 31, 2013 based on a market approach utilizing an average 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 unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for each of the years ended December 31, 2013 and 2012 are summarized as follows (in millions):

	Natural Gas Pipelines	CO_2–KMP	Products Pipelines-KMP	Terminals–KMP	Kinder Morgan Canada–KMP	Total
Historical Goodwill	$ 3,723	$ 1,528	$ 2,129	$ 1,484	$ 621	$ 9,485
Accumulated impairment losses	(2,090)	—	(1,267)	(677)	(377)	(4,411)
Balance as of December 31, 2011	1,633	1,528	862	807	244	5,074
Acquisitions(a)	18,803	—	—	—	—	18,803
Disposals(b)	(250)	—	—	—	—	(250)
Currency translation adjustments	—	—	—	—	5	5
Balance as of December 31, 2012	20,186	1,528	862	807	249	23,632
Acquisitions(c)	888	—	—	—	—	888
Currency translation adjustments	—	—	—	—	(16)	(16)
Balance as of December 31, 2013	$ 21,074	$ 1,528	$ 862	$ 807	$ 233	$ 24,504

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(a) 2012 acquisition amount consists of the EP and EP Midstream acquisitions as discussed in Note 3.

(b) 2012 disposal amount relates to the sale of KMP's FTC Natural Gas Pipelines disposal group as discussed in Note 3. Since the FTC Natural Gas Pipelines disposal group represented a significant portion of our Natural Gas Pipelines business segment, we allocated the goodwill of the segment based on the relative fair value of the portion being disposed of and the portion of the segment remaining.

(c) 2013 acquisition amount consists of $881 million relating to KMP's May 1, 2013 Copano acquisition as discussed in Note 3, and $7 million relating to other EP acquisition assets.

For more information on our accounting for goodwill, see Note 2.

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 $809 million and $714 million as of December 31, 2013 and 2012, respectively. In almost all instances, this differential, relating to the discrepancy between our share of the investee's recognized net assets at book values and at current fair values, represents our share of undervalued depreciable assets, and since those assets (other than land) are subject to depreciation, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2013, this excess investment cost is being amortized over a weighted average life of approximately fifteen years.

The second differential, representing total unamortized excess cost over underlying fair value of net assets acquired (equity method goodwill) totaled $138 million as of both December 31, 2013 and 2012. This differential is not subject to amortization but rather to impairment testing. Accordingly, in addition to our annual impairment test of goodwill, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method, as well as the amortization period for such assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives. Our impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. As of December 31, 2013, we believed no such impairment had occurred and no reduction in estimated useful lives was warranted.

Other Intangibles

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 subject to amortization, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. As of December 31, 2013 and 2012, these intangible assets totaled $2,438 million and $1,171 million, respectively, and primarily consisted of customer contracts, relationships and agreements associated with the Natural Gas Pipelines and Terminals-KMP 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 each of the years ended December 31, 2013, 2012 and 2011, the amortization expense on our intangibles totaled $125 million, $86 million and $65 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2014 – 2018) is approximately $141 million, $136 million, $134 million, $132 million, and $130 million respectively. As of December 31, 2013, the weighted average amortization period for our intangible assets was approximately twenty years.

8. 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 using the effective interest rate method. The following table provides detail on the principal amount of our outstanding debt balances as of December 31, 2013 and 2012. The table amounts exclude all debt fair value adjustments, including debt discounts and premiums (in millions):

	December 31, 2013	December 31, 2012
KMI		
Senior term loan facility, variable rate, due May 24, 2015	$ 1,528	$ 2,714
Senior notes and debentures, 5.00% through 7.45%, due 2015 through 2098(a)	1,815	315
Credit facility due December 31, 2014(b)	175	1,035
Subsidiary borrowings (as obligor)		
K N Capital Trust I and III, deferrable interest debentures issued by subsidiary trusts, 7.63% and 8.56%, due 2027 and 2028(c)	27	27
Kinder Morgan Finance Company, LLC, senior notes, 5.70% through 6.40%, due 2016 through 2036(a)(d)	1,636	1,636
El Paso, senior notes, 6.50% through 12.00%, due 2013 through 2037(a)	3,830	3,860
EPC Building, LLC, promissory note, 3.967%, due 2013 through 2035(e)	461	217
Colorado Interstate Gas Services Company, 7.76% Totem note payable, due 2018	1	1
Other credit facilities due December 20, 2013, March 20 and June 20, 2014	193	210
EP preferred securities, 4.75%, due March 31, 2028(f)	280	286
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock(g)	100	100
Total debt – KMI	10,046	10,401
Less: Current portion of debt – KMI	(725)	(1,153)
Total long-term debt – KMI(h)	$ 9,321	$ 9,248
KMP and EPB		
KMP		
Senior notes, 2.65% through 9.00%, due 2013 through 2043(a)	$ 15,600	$ 13,350
Commercial paper borrowings(i)	979	621
Credit facility due May 1, 2018(j)	—	—
KMP subsidiary borrowings (as obligor)		
TGP senior notes, 7.00% through 8.375%, due 2016 through 2037(k)	1,790	1,790
EPNG senior notes, 5.95% through 8.625%, due 2017 through 2032(l)	1,115	1,115
Copano senior notes, 7.125% due April 1, 2021(m)	332	—
Other miscellaneous subsidiary debt	98	186
Total debt – KMP	19,914	17,062
Less: Current portion of debt – KMP(n)	(1,504)	(1,155)
Total long-term debt – KMP(h)	18,410	15,907
EPB		
EPPOC		
Senior notes, 4.10% through 8.00%, due 2013 through 2042(o)	2,260	2,348
Credit facility due May 27, 2016(p)	—	—
EPB subsidiary borrowings (as obligor)		
Colorado Interstate Gas Company, L.L.C. (CIG), senior notes, 5.95% through 6.85%, due 2015 through 2037(q)	475	475
SLNG senior notes, 9.50% through 9.75%, due 2014 through 2016(a)(r)	135	135
SNG notes, 4.40% through 8.00%, due 2017 through 2032(s)	1,211	1,211
Other financing obligations(t)	175	178
Total debt – EPB	4,256	4,347
Less: Current portion of debt – EPB	(77)	(93)
Total long-term debt – EPB(h)	4,179	4,254
Total long-term debt – KMP and EPB	$ 22,589	$ 20,161

(a) 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.

(b) As of December 31, 2013 and 2012, the weighted average interest rates on KMI's credit facility borrowings were 2.67% and 2.72%, respectively.

(c) KMI's business trusts, K N Capital Trust I and K N Capital Trust III, are obligated for $13 million of 8.56% Capital Trust Securities maturing on April 15, 2027 and $14 million of 7.63% Capital Trust Securities maturing on April 15, 2028, respectively, which it guarantees. The 2028 securities are redeemable in whole or in part, at KMI's option at any time, at redemption prices as defined in the associated prospectus. The 2027 securities are redeemable in whole or in part at KMI's option and at any time in certain limited circumstances upon the occurrence of certain events and at prices all defined in the associated prospectus supplements. Upon redemption by KMI or at maturity of the Junior Subordinated Deferrable Interest Debentures, the proceeds must be used to make redemptions of the Capital Trust Securities on a pro rata basis.

(d) Each series of these notes is fully and unconditionally guaranteed by KMI on a senior secured basis as to principal, interest and any additional amounts required to be paid as a result of any withholding or deduction for Canadian taxes.

(e) EPC Building, LLC, as the landlord, leases the property to KMI as a tenant.

(f) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2013, had $5.6 million of 4.75% trust convertible preferred securities outstanding (referred to as the EP 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. EP provides a full and unconditional guarantee of the EP Trust I Preferred Securities. There are no significant restrictions on EP's ability to obtain funds from its subsidiaries by distribution, dividend or loan. The EP 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 KMI Class P common stock; (ii) $25.18 in cash without interest; and (iii) 1.100 warrants to purchase a share of KMI 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 EP Trust I Preferred Securities into debt and equity components and as of December 31, 2013, the outstanding balance of $280 million (of which $141 million is classified as current) was bifurcated between debt ($247 million) and equity ($33 million). During the years ended December 31, 2013 and 2012, 107,618 and 781,633 EP Trust I Preferred Securities had been converted into (i) 77,442 and 562,521 shares of KMI Class P common stock; (ii) approximately $3 million and $20 million in cash; and (iii) 118,377 and 859,796 in warrants, respectively.

(g) As of December 31, 2013, KMGP had outstanding 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Until August 18, 2012, dividends accumulated, commencing on the issue date, at a fixed rate of 8.33% per annum and were 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, 2007. After 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. (see "—KMGP Preferred Shares" below).

(h) Excludes debt fair value adjustments. As of December 31, 2013 and December 31, 2012, our total "Debt fair value adjustments" increased our combined debt balances by $1,977 million and $2,591 million, respectively. In addition to all unamortized debt discount/premium amounts and purchase accounting on our debt balances, our debt fair value adjustments also include (i) amounts associated with the offsetting entry for hedged debt; and (ii) 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 13.

(i) In May 2013, in association with the increase of capacity negotiated for KMP's senior unsecured revolving bank credit facility (see "—Credit Facilities and Restrictive Covenants—KMP" below), KMP increased its commercial paper program by $500 million to provide for the issuance of up to $2.7 billion. As of December 31, 2013 and December 31, 2012, the average interest rates on KMP's outstanding commercial paper borrowings were 0.28% and 0.45%, respectively. The borrowings under KMP's commercial paper program were used principally to finance the acquisitions and capital expansions it made during 2013 and 2012.

(j) See "Credit Facilities and Restrictive Covenants—KMP" below.

(k) Consists of six separate series of fixed-rate unsecured senior notes that KMP assumed as part of the August 2012 drop-down transaction.

(l) Consists of four separate series of fixed-rate unsecured senior notes that KMP assumed as part of the August 2012 and March 2013 drop-down transactions.

(m) Consists of a single series of fixed-rate unsecured senior notes that KMP guaranteed as part of its May 1, 2013 Copano acquisition. The notes mature on April 1, 2021, and interest on the notes is payable semiannually on April 1 and October 1 of each year. For further information about these notes, see "—KMP's Copano Debt" below.

(n) Includes commercial paper borrowings.

(o) EPB's only operating asset is its investment in EPPOC, and EPPOC's only operating assets are its investments in Wyoming Interstate Company, L.L.C. (WIC), CIG, SLNG, Elba Express, SNG, ELC and Cheyenne Plains Gas Pipeline Company, L.L.C. (CPG), (collectively, the non-guarantor operating companies). EPB and EPPOC's independent assets and operations, other than those related to these investments and EPPOC's debt are less than 3% of the total assets and operations of EPB, and thus substantially all of the operations and assets exist within these non-guarantor operating companies. Furthermore, there are no significant restrictions on EPPOC or EPB's ability to access the net assets or cash flows related to its controlling interests in the operating companies either through dividend or loan. The restrictive covenants under these debt obligations are no more restrictive than the restrictive covenants under EPB's credit facility.

(p) LIBOR plus 1.75%.

(q) CIG is subject to a number of restrictions and covenants under its debt obligation. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(r) The SLNG senior notes impose certain limitations on the ability of SLNG to, among other things, incur additional indebtedness, make certain restricted payments, enter into transactions with affiliates, and merge or consolidate with any other person, sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its assets. SLNG is required to comply with certain financial covenants, including a leverage ratio of no more than 5.0 to 1.0 and an interest coverage ratio of no less than 2.0 to 1.0. The SLNG senior notes are subject to a change of control prepayment offer in the event of a ratings downgrade within a 120-day period from and including the date on which a change of control with respect to SLNG occurs (as defined in the note purchase agreement). If a sufficient number of the rating agencies downgrade the ratings of the SLNG notes below investment grade within the 120-day period from and including the date of any such change of control, then SLNG is required to offer to prepay the entire unpaid principal amount of the notes held by each holder at 101% of the principal amount of such SLNG notes (without any make-whole amount or other penalty), together with interest accrued thereon to the date for such prepayment.

(s) Under its indentures, SNG is subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens. SNIC is a wholly owned finance subsidiary of SNG and is the co-issuer of certain of SNG's outstanding debt securities. SNIC has no material assets, operations, revenues or cash flows other than those related to its service as a co-issuer of the debt securities. Accordingly, it has no ability to service obligations on the debt securities.

(t) 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. EPB reflected the payments made by their joint venture partner as other long-term liabilities on the balance sheet during construction and upon project completion, the advances were converted into a financing obligation to WYCO. Upon placing these projects in service, EPB transferred its title in the projects to WYCO and leased the assets back. Although EPB transferred the title in these projects to WYCO, the transfer did not qualify for sale leaseback accounting because of EPB's continuing involvement through its equity investment in WYCO. As such, the costs of the facilities remain on our balance sheets and the advanced payments received from EPB's 50% joint venture partner were converted into a financing obligation due to WYCO. As of December 31, 2013, the principal amounts of the Totem and High Plains financing obligations were $75 million and $94 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. The interest rate on these obligations is 15.5%, payable on a monthly basis.

Credit Facilities and Restrictive Covenants

KMI

On February 10, 2012, KMI entered into the following agreements which were effective with the May 25, 2012 acquisition of EP: (i) an amendment to its existing $1 billion revolving credit facility to, among other things, permit the EP acquisition, to fund, in part, the transactions and related costs and expenses, and to provide for ongoing working capital and for other general corporate purposes; (ii) an incremental joinder agreement which provides for $750 million in additional commitments under the existing revolving credit facility; and (iii) an acquisition debt facilities credit agreement (Acquisition Credit Facility) containing a 364-day bridge facility and a $5 billion 3-year term loan facility, the proceeds of which were used to finance a portion of the cash consideration and related fees and expenses paid in connection with the EP acquisition.

The amended and restated credit facility provides that the $1.75 billion revolver bears interest, at KMI's option, at either (i) the adjusted LIBOR plus an applicable margin per annum varying from 2.50% per annum to 4.25% per annum depending on the publicly announced debt ratings for senior secured non-credit enhanced long-term indebtedness for borrowed money of KMI or (ii) an alternate base rate plus an applicable margin varying from 1.50% per annum to 3.25% per annum depending on debt ratings of KMI. In August 2012, we repaid the remaining outstanding balance of the 364-day bridge facility and terminated the facility. In November 2012, the terms of KMI's $1.75 billion senior secured revolving credit facility were amended to decrease the fixed spread component of our floating interest rate by 100 basis points and to extend the maturity of the revolver to December 31, 2014. As of December 31, 2013, KMI was in compliance with all required financial covenants (described following).

KMI's credit facility included the following restrictive covenants as of December 31, 2013:

- total debt divided by earnings before interest, income taxes, depreciation and amortization may not exceed 6.00: 1.00;
- 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.

The Acquisition Credit Facility provides that:

- the term loans under the term loan facility bears interest, at KMI's option, at either (i) adjusted LIBOR plus an applicable margin varying from 3.00% per annum to 4.75% per annum depending on certain debt ratings of KMI or (ii) an alternate base rate plus an applicable margin varying from 2.00% per annum to 3.75% per annum depending on certain debt ratings of KMI.

As of December 31, 2013, we had $175 million outstanding under KMI's $1.75 billion credit facility and $80 million in letters of credit. Our availability under this facility as of December 31, 2013 was $1,495 million.

KMP

On May 1, 2013, KMP replaced its previous $2.2 billion, senior unsecured revolving credit facility that was due July 1, 2016, with a new $2.7 billion five-year senior unsecured revolving credit facility expiring May 1, 2018. Borrowings under the credit facility can be used for general partnership purposes and as a backup for KMP's commercial paper program, and borrowings under the commercial paper program reduce the borrowings allowed under KMP's credit facility. KMP had no borrowings under the credit facility as of December 31, 2013, and there were no borrowings under its previous credit facility as of December 31, 2012. KMP's new credit facility's financial covenants are substantially similar to those in the previous facility, and as of December 31, 2013, KMP was in compliance with all required financial covenants (described following). KMP's credit facility provides that both the margin KMP will pay with respect to borrowings and the facility fee KMP will pay on the total commitment, will vary based on its senior debt credit rating. Interest on the credit facility accrues at KMP's option at a floating rate equal to either:

- the administrative agent's base rate, plus a margin, which varies depending upon the credit rating of KMP's long-term senior unsecured debt (the administrative agent's base rate is a rate equal to the greatest of (i) the Federal Funds Rate, plus 0.5%; (ii) the Prime Rate; or (iii) LIBOR for a one -month eurodollar loan, plus 1%); or
- LIBOR for a one -month eurodollar loan, plus a margin, which varies depending upon the credit rating of KMP's long-term senior unsecured debt.

As of December 31, 2013, KMP had $979 million of commercial paper borrowings outstanding under its $2.7 billion credit facility and $203 million in letters of credit. KMP's availability under its facility as of December 31, 2013 was $1,518 million.

KMP's credit facility included the following restrictive covenants as of December 31, 2013:

- total debt divided by earnings before interest, income taxes, depreciation and amortization for the preceding four quarters may not exceed:
  - 5.5, in the case of any such period ended on the last day of (i) a fiscal quarter in which KMP makes any Specified Acquisition (as defined in the credit facility) or (ii) the first or second fiscal quarter next succeeding such a fiscal quarter; or
  - 5.0, in the case of any such period ended on the last day of any other fiscal quarter;
- certain limitations on entering into mergers, consolidations and sales of assets;
- limitations on granting liens; and
- prohibitions on making any distribution to holders of units if an event of default exists or would exist upon making such distribution.

In addition to normal repayment covenants, under the terms of KMP's credit facility, the occurrence at any time of any of the following would constitute an event of default: (i) KMP's failure to make required payments of any item of indebtedness or any payment in respect of any hedging agreement, provided that the aggregate outstanding principal amount for all such indebtedness or payment obligations in respect of all hedging agreements is equal to or exceeds $75 million; (ii) KMP's general partner's failure to make required payments of any item of indebtedness, provided that the aggregate outstanding principal amount for all such indebtedness is equal to or exceeds $75 million; (iii) adverse judgments rendered against KMP for the payment of money in an aggregate amount in excess of $75 million, if this same amount remains undischarged for a period of thirty consecutive days during which execution shall not be effectively stayed; and (iv) voluntary or involuntary commencements of any proceedings or petitions seeking KMP's liquidation, reorganization or any other similar relief under any federal, state or foreign bankruptcy, insolvency, receivership or similar law.

KMP's credit facility does not contain a material adverse change clause coupled with a lockbox provision; however, the facility does provide that the margin KMP will pay with respect to borrowings, and the facility fee that it will pay on the total commitment, will vary based on its senior debt credit rating. None of KMP's debt is subject to payment acceleration as a result of any change to its credit ratings.

EPB

In May 2011, EPPOC and WIC entered into an unsecured five-year credit facility with an initial aggregate borrowing capacity of $1 billion, expandable to $1.5 billion for certain expansion projects and acquisitions. EPPOC is a wholly owned subsidiary of EPB. In May 2012, EPB borrowed from the revolving credit facility to fund the acquisition of CPG and the remaining interest in CIG. On May 24, 2012, Standard & Poor's Rating Service raised EPB's credit rating, triggering a pricing level change. EPB's interest rate for borrowings under the credit facility has decreased from the LIBOR plus 2% to LIBOR plus 1.75% and the commitment fee paid for unutilized commitments decreased from 0.4% to 0.3% and these rates remained effective at December 31, 2013. As of December 31, 2013, EPB had no outstanding balance under its revolving credit facility. EPB's remaining availability under this facility was $1 billion. Borrowings under the credit facility are guaranteed by EPB.

EPB's credit facility included the following restrictive covenants as of December 31, 2013:

- EPB and WIC's consolidated total debt divided by earnings before interest, income taxes, depreciation and amortization as of the end of each quarter may not exceed:
  - 5.0 to 1.0 for any trailing four consecutive quarter period; and
  - 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified permitted acquisitions having a value greater than $25 million;
- certain limitations on entering into mergers, consolidations and sales of assets;
- limitations on granting liens; and
- prohibitions on making any distribution to holders of units if an event of default exists or would exist upon making such distribution.

EPB also has additional flexibility to the covenants for growth projects. In case of a capital construction or expansion project in excess of $20 million, pro forma adjustments to consolidated earnings before interest, income taxes, depreciation and amortization, approved by the lenders, may be made based on the percentage of capital costs expended and projected cash flows for the project. Such adjustments shall be limited to 25% of actual consolidated earnings before interest, income taxes, depreciation and amortization.

The credit facility contains certain customary events of default that affect EPB, the borrowers and EPB's other restricted subsidiaries, including, without limitation, (i) nonpayment of principal when due or nonpayment of interest or other amounts within five business days when due; (ii) bankruptcy or insolvency with respect to EBP, its general partner, the borrowers or any of EPB's other restricted subsidiaries; (iii) judgment defaults against EPB, its general partner, the borrowers or any of EPB's other restricted subsidiaries in excess of $50 million; or (iv) the failure of El Paso to directly or indirectly own a majority of the voting equity of EPB's general partner and a failure by EPB to directly or indirectly own 100% of the equity of EPPOC.

KMP's Copano Debt

As of the May 1, 2013 Copano acquisition date, KMP assumed the following outstanding Copano debt amounts (i) $404 million of outstanding borrowings under Copano's revolving credit facility due June 10, 2016; (ii) $249 million aggregate principal amount of Copano's 7.75% unsecured senior notes due June 1, 2018; and (iii) $510 million aggregate principal amount of Copano's 7.125% unsecured senior notes due April 1, 2021. Immediately following the acquisition, KMP repaid the outstanding $404 million of borrowings under Copano's revolving credit facility, and terminated the credit facility at the time of such repayment. On June 1, 2013, KMP paid $259 million (based on a price of 103.875% of the principal amount) to fully redeem and retire the 7.75% series of senior notes in accordance with the terms and conditions of the indenture governing the notes. As part of its May 1, 2013 purchase price allocation, KMP valued the 7.75% senior notes equal to the $259 million redemption value and accordingly, no gain or loss was recorded from this debt retirement. KMP utilized borrowings under its commercial paper program for both of these debt retirements.

On September 4, 2013, KMP paid $191 million to complete the partial redemption and retirement of $178 million (35%) of the total $510 million outstanding principal amount of Copano's 7.125% senior notes, (excluding a $6 million payment for accrued and unpaid interest on the redeemed notes as of September 4, 2013). As part of its May 1, 2013 purchase price allocation, KMP valued the repaid portion of the 7.125% senior notes equal to the $191 million redemption value and accordingly, KMP recorded no gain or loss from this debt retirement. As of December 31, 2013, an aggregate principal amount of $332 million of 7.125% senior notes remained outstanding.

Debt Issuances and Repayments

Apart from the changes in KMP's Copano debt discussed above, following are significant long-term debt issuances and repayments made during 2013 and 2012:

	2013	2012
KMI		
Issuances	$750 million 5.00% notes due 2021	$12,178 million of EP debt assumed as of the May 25, 2012 acquisition date
	$750 million 5.625% notes due 2023	$5,000 million senior term loan facility due 2015
	$251 million EPC Building, LLC 3.967% promissory notes(a)	$217 million EPC Building, LLC 3.967% promissory notes(a)
Repayments	$1,186 million senior term loan facility due 2015	$839 million 6.50% notes due 2012
		$2,286 million senior term loan facility due 2015
KMP		
Issuances	$600 million 3.50% notes due 2023	$1,000 million 3.95% notes due 2022
	$700 million 5.00% notes due 2043	$625 million of 3.45% notes due 2023
	$800 million 2.65% notes due 2019	$625 million of 5.00% notes due 2042
	$650 million 4.15% notes due 2024	
Repayments	$500 million 5.00% notes due 2013	$450 million of 7.125% notes due 2012
		$500 million of 5.85% notes due 2012
EPB (through EPPOC)		
Issuances		$475 million 4.70% notes due 2042
Repayments	$88 million 8.00% notes due 2013	

(a) In December 2012, our subsidiary, EPC Building, LLC had issued $468 million of 3.967% amortizing promissory notes with payments due 2013 through 2035, of which $217 million was issued to third parties and the remaining $251 million was held by KMI until they were sold to third parties in April of 2013. Proceeds from the issuance of the notes were used to reduce KMI's credit facility borrowings.

KMGP Preferred Shares

The following table provides information about KMGP's distributions on 100,000 shares of its Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock:

	Year Ended December 31,	
	2013	2012
Per share cash distribution declared for the period(a)	$ 42.101	$ 63.236
Per share cash distribution paid in the period	$ 42.169	$ 73.423

(a) On January 15, 2014, KMGP declared a distribution for the three months ended December 31, 2013, of $10.570 per share, which was paid on February 18, 2014 to shareholders of record as of January 31, 2014.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2013, are summarized as follows (in millions):

Year	KMI	KMP	EPB
2014	$ 725	$ 1,504	$ 77
2015	1,788	300	756
2016	928	750	69
2017	798	1,255	505
2018	1,322	1,000	5
Thereafter	4,485	15,105	2,844
Total	$ 10,046	$ 19,914	$ 4,256

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 5.08% during 2013 and 4.92% during 2012. Information on our interest rate swaps is contained in Note 13. For information about our contingent debt agreements, see Note 12.

Subsequent Events

On January 17, 2014, KMP entered into a short-term unsecured liquidity facility. This liquidity facility provides for borrowings up to $1.0 billion with a term of six months. The covenants of this facility are substantially similar to the covenants of KMP's existing senior credit facility that is due May 1, 2018. In conjunction with the establishment of KMP's liquidity facility, KMP increased its commercial paper program to provide for the issuance of up to $3.7 billion (up from $2.7 billion). KMP's liquidity facility supports its commercial paper program and borrowings under its commercial paper program reduce the borrowings allowed under KMP's liquidity facility. As of the date of this report, KMP has no borrowings under its liquidity facility.

On February 19, 2014, KMP priced in a public offering $750 million of 3.50% senior notes due March 1, 2021 and $750 million of 5.50% senior notes due March 1, 2044.

9. Share-based Compensation and Employee Benefits

Share-based Compensation

Kinder Morgan, Inc.

We completed an initial public offering in February 2011 as discussed further in Note 10 "Stockholders' Equity—Kinder Morgan, Inc.—Initial Public Offering." As a result of our initial public offering, our outstanding Class B units and Class A-1 units were converted to Class B shares and Class C shares, respectively. As of December 26, 2012, all class B and C shares had converted into Class P shares.

Class P Shares

Stock Compensation Plan for Non-Employee Directors

In connection with our initial public offering, we adopted the Stock Compensation Plan for Non-Employee Directors, in which our independent directors will participate. None of the 11 directors nominated by Richard D. Kinder or the Sponsor Investors participate in the plan. The plan recognizes that the compensation paid to each 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 non-employee director who was not nominated by Richard D. Kinder or one of the Sponsor Investors, referred to as "eligible directors," 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 2013, 2012 and 2011, we made restricted Class P common stock grants to our non-employee directors of 5,710, 5,520 and 1,570, respectively. These grants were valued at time of issuance at $210,000, $185,000 and $45,000, respectively. All of the restricted stock grants made to non-employee directors vest during a six-month period.

Restricted Stock and Long-term Incentive Retention Award Plan

Upon our initial public offering, our restricted stock compensation program replaced our Long-term Incentive Retention Award Plan. Our restricted stock compensation program is available to employees eligible under the former Long-term Incentive Retention Award Plan, discussed below. The following table sets forth a summary of activity and related balances of our restricted stock excluding that issued to non-employee directors (in millions, except share amounts):

	Year Ended December 31, 2013		Year Ended December 31, 2012		February 11, 2011 Through December 31, 2011	
	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	2,154,022	$ 69	1,163,090	$ 33	—	$ —
Granted	4,563,495	181	1,463,388	51	980,851	28
Shares issued in exchange for cash awards	—	—	—	—	213,040	6
Vested	(83,444)	(3)	(102,033)	(3)	—	—
Forfeited	(251,188)	(8)	(370,423)	(12)	(30,801)	(1)
Outstanding at end of period	6,382,885	$ 239	2,154,022	$ 69	1,163,090	$ 33
Intrinsic value of restricted stock vested during the period		$ 3		$ 4		$ —

Restricted stock grants made to employees have vesting periods ranging from 2 years with variable vesting dates to 7 years. Following is a summary of the future vesting of our outstanding restricted stock grants:

Year	Vesting of Restricted Shares
2014	449,043
2015	741,959
2016	1,339,735
2017	470,049
2018	1,172,468
2019	1,531,087
2020	603,072
2021	20,126
2023	55,346
Total Outstanding	6,382,885

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

During 2013, 2012 and 2011, we recorded $35 million, $14 million and $4 million, respectively, in expense related to restricted stock grants. In addition, in conjunction with the exchange for restricted shares discussed above, we recorded an increase to additional paid-in capital in the amount of $2 million in 2011. At December 31, 2013 and 2012, unrecognized restricted stock compensation expense, less estimated forfeitures, was approximately $177 million and $49 million, respectively.

From 2006 until our initial public offering, we elected not to make any restricted stock awards as a result of a 2007 going private transaction. To ensure that certain key employees who had previously received restricted stock and restricted stock unit awards continued under a long-term retention and incentive program, the Company implemented the Long-term Incentive Retention Award plan. The plan provided cash awards approved by the compensation committees of the Company which were granted in July of each year to recommended key employees. Senior management was not eligible for these awards. These grants required the employee to sign a grant agreement. The grants vested 100% after the third year anniversary of the grant provided the employee remained with the Company. The remaining grants outstanding were made in July of 2010. During the years ended December 31, 2013, 2012, and 2011, we expensed $2 million, $7 million and $13 million, respectively, related to these grants.

Awards of Participation Interests in a 2007 Going Private Transaction

In connection with our 2007 going private transaction, members of management were awarded Kinder Morgan Holdco LLC Class A-1 and Class B units. In accordance with generally accepted accounting principles, we were required to recognize compensation expense in connection with the Class A-1 and Class B units over the expected life of such units; however, we did not have any obligation, nor did we pay any amounts related to these compensation expenses as all expenses were borne by the Investors, and since we were not responsible for paying these expenses, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Stockholders Equity" on our balance sheet. The awards and terms of the Class B units granted to members of management were determined after extensive negotiations between management and the Sponsor Investors with respect to which management agreed to forego any long-term executive compensation at least until the Sponsor Investors sell their interests in us or convert their Class A shares into Class P shares. The Class B units were converted into Class B shares, and the class A-1 units were converted into Class C shares in connection with our initial public offering. The aggregate amount of our Class P common stock into which the Class A shares, Class B shares and Class C shares could convert was fixed. The conversion of Class B shares into Class P shares reduced the number of Class P shares into which the Class A shares and Class C shares could convert. Therefore, we view the Class B shares, along with the Class A shares and Class C shares, as participation interests in a going private transaction, rather than as awards of stock-based compensation. As of December 26, 2012, all class B and C shares had converted into Class P shares.

Kinder Morgan Energy Partners, L.P.

On January 18, 2005, KMR's compensation committee established the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors. The plan is administered by KMR's compensation committee and KMR's board has sole discretion to terminate the plan at any time. The primary purpose of this plan is to promote KMP's interests and the interests of its unitholders by aligning the compensation of the non-employee members of the board of directors of KMR with KMP unitholders' interests. Further, since KMR's success is dependent on its operation and management of KMP's business and its resulting performance, the plan is expected to align the compensation of the non-employee members of the board with the interests of KMR's shareholders.

The Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors recognizes that the compensation to be paid to each non-employee director is fixed by the KMR board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving cash compensation, each non-employee director may elect to receive common units. Each election is made generally at or around the first board meeting in January of each calendar year and is effective for the entire calendar year. A non-employee director may make a new election each calendar year. The total number of common units authorized under this compensation plan is 100,000. All common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. A total of 2,450 common units were issued to non-employee directors in 2011 as a result of their elections to receive common units in lieu of cash compensation.

Pension and Other Postretirement Benefit Plans

Overview of Retirement 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. In connection with the EP acquisition, we assumed EP's defined contribution savings plan which was merged into our savings plan during 2012. In connection with KMP's Copano acquisition, we assumed Copano's defined contribution savings plan which was merged into our savings plan during 2013. The total amount charged to expense for our savings plan was approximately $40 million, $32 million, and $24 million for the years ended December 31, 2013, 2012, and 2011, 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 a career pay formula.

In connection with the EP acquisition, we assumed EP's defined benefit pension plans including a cash balance plan and a supplemental executive retirement plan ("SERP"). These plans had combined benefit obligations of $2,407 million and assets of $1,949 million as of the May 25, 2012 acquisition date. We merged the EP cash balance plan into our cash balance plan on December 31, 2012. We terminated the EP SERP and partially settled the plan's benefit obligation during 2012. The $28 million SERP obligation that remained as of December 31, 2012 was settled in February 2013.

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.

In connection with the EP acquisition, we assumed EP's OPEB plans including retiree medical and life insurance benefits. These plans had aggregate benefit obligations of $606 million and assets of $273 million as of the May 25, 2012 acquisition date.

Additionally, KMP's 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, 2013 and 2012, and includes information regarding the EP Pension and OPEB plans since the May 25, 2012 acquisition date (in millions):

	Pension Benefits		OPEB	
	2013	2012	2013	2012
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 2,792	$ 343	$ 720	$ 91
Service cost	25	18	—	—
Interest cost	92	67	23	18
Actuarial (gain) loss	(132)	178	(38)	40
Benefits paid	(239)	(58)	(54)	(37)
Participant contributions	—	—	11	7
Medicare Part D subsidy receipts	—	—	6	1
Business combination(a)	—	2,407	—	606
Plan amendments	25	(17)	(37)	(5)
Curtailments, settlements and special termination benefits(b)	—	(146)	—	(1)
Benefit obligation at end of period	2,563	2,792	631	720
Change in plan assets:				
Fair value of plan assets at beginning of period	2,240	258	341	55
Actual return on plan assets	254	203	40	24
Employer contributions	78	32	42	19
Participant contributions	—	—	11	7
Benefits paid	(239)	(58)	(54)	(37)
Business combination(a)	—	1,949	—	273
Settlements(b)	—	(144)	—	—
Fair value of plan assets at end of period	2,333	2,240	380	341
Funded status - net liability at December 31,	$ (230)	$ (552)	$ (251)	$ (379)

(a) Reflects the acquisition date amount of benefit plan obligations and assets assumed from El Paso.

(b) Reflects the settlement of benefit obligations associated with certain participants in the acquired El Paso plans as a result of the sale of EP Energy, a reduction in force and termination of the SERP.

Components of Funded Status . The following table details the amounts recognized in our balance sheet at December 31, 2013 and 2012 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2013	2012	2013	2012
Non-current benefit asset	$ —	$ —	$ 224	$ 135
Current benefit liability	—	(28)	(32)	(33)
Non-current benefit liability	(230)	(524)	(443)	(481)
Funded status - net liability at December 31,	$ (230)	$ (552)	$ (251)	$ (379)

Components of Accumulated Other Comprehensive Income (Loss) . The following table details the amounts of pre-tax accumulated other comprehensive income (loss) at December 31, 2013 and 2012 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	
	2013	2012	2013	2012
Unrecognized net actuarial loss	$ (10)	$ (218)	$ (17)	$ (70)
Unrecognized prior service (cost) credit	(5)	20	21	4
Accumulated other comprehensive (loss) income	$ (15)	$ (198)	$ 4	$ (66)

We anticipate that less than $1 million of pre-tax accumulated other comprehensive loss will be recognized as part of our net periodic benefit cost in 2014, including approximately $1 million of unrecognized net actuarial loss and approximately $1 million of unrecognized prior service credit.

Our accumulated benefit obligation for our defined benefit pension plans was $2,516 million and $2,773 million at December 31, 2013 and 2012, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $534 million and $569 million at December 31, 2013 and 2012, respectively. The fair value of these plans' assets was approximately $60 million and $55 million at December 31, 2013 and 2012, 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 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, 2013, the target asset allocations in effect for the pension plan were 50%, equity, 45% fixed income and 5% company securities. As of December 31, 2013, the target asset allocations in effect for the retiree medical and retiree life insurance plans were 70% equity and 30% fixed income.

Below are the details of our pension and OPEB plan assets classified by level 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 dollar-denominated money market funds, 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, common/collective trust funds, mutual funds, limited partnerships, trusts, fixed income and other securities. Money market funds are valued at amortized cost, which approximates fair value. The common/collective trust funds', mutual funds', limited partnerships' and trusts' fair values are based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. 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 and are also subject to certain restrictions associated with the timing of redemption which extend beyond 90 days as of December 31. Included in this level are insurance contracts, mutual funds with significant redemption restrictions, limited partnerships and private equity. Insurance contracts are valued at contract value, which approximates fair value. The mutual funds' fair values are primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. The limited partnerships' and private equity investments' fair values are primarily based on the securities' value as reported by the issuer, which may be determined utilizing discounted present value.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value classified in each level at December 31, 2013 and 2012 (in millions):

	Pension Assets							
	2013				2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Money market funds	$ —	$ —	$ —	$ —	$ 1	$ 6	$ —	$ 7
Common/collective trusts(a)	—	940	—	940	—	765	—	765
Insurance contracts	—	—	15	15	—	—	14	14
Mutual funds(b)	92	134	—	226	—	266	40	306
Common and preferred stocks(c)	498	—	—	498	812	—	—	812
Corporate bonds	—	220	—	220	—	111	—	111
U.S. government securities	—	120	—	120	—	99	—	99
Asset backed securities	—	29	—	29	—	25	—	25
Limited partnerships	—	—	28	28	—	—	24	24
Equity trusts	—	235	—	235	—	53	—	53
Private equity	—	—	9	9	—	—	9	9
Other	—	13	—	13	—	15	—	15
Total asset fair value(c)	$ 590	$ 1,691	$ 52	$ 2,333	$ 813	$ 1,340	$ 87	$ 2,240

(a) For 2013, this category includes common/collective trust funds which are invested in approximately 36% fixed income, 62% equity and 2% short term securities. For 2012, this category includes common/collective trusts funds which are invested in approximately 59% fixed income, 36% equity and 5% short term securities.

(b) For 2013, this category includes mutual funds which are invested in approximately 60% fixed income and 40% equity. For 2012, this category includes mutual funds which are invested in approximately 28% fixed income, 72% equity and other investments.

(c) Plan assets include $229 million and $133 million of KMI Class P common stock for 2013 and 2012, respectively.

	OPEB Assets							
	2013				2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Money market funds	$ —	$ —	$ —	$ —	$ 11	$ 1	$ —	$ 12
Domestic equity securities	13	—	—	13	—	—	—	—
Common/collective trusts(a)	—	85	—	85	—	277	—	277
Limited partnerships	92	72	—	164	—	—	—	—
Insurance contracts	—	—	46	46	—	—	44	44
Mutual funds	72	—	—	72	—	8	—	8
Total asset fair value	$ 177	$ 157	$ 46	$ 380	$ 11	$ 286	$ 44	$ 341

(a) For 2013, this category includes common/collective trust funds which are invested in approximately 70% equity and 30% fixed income securities. For 2012, this category includes common/collective trust funds which are invested in approximately 65% equity and 35% fixed income securities.

The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2013 and 2012, including the EP Pension and OPEB plans since the May 25, 2012 acquisition date (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
2013					
Insurance contracts	$ 14	$ —	$ —	$ 1	$ 15
Mutual funds	40	—	—	(40)	—
Limited partnerships	24	—	3	1	28
Private equity	9	—	1	(1)	9
Total	$ 87	$ —	$ 4	$ (39)	$ 52
2012					
Insurance contracts	$ 14	$ —	$ —	$ —	$ 14
Mutual funds	—	38	2	—	40
Limited partnerships	4	16	—	4	24
Private equity	9	—	—	—	9
Total	$ 27	$ 54	$ 2	$ 4	$ 87

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2013					
Insurance contracts	$ 44	$ —	$ —	$ 2	$ 46
Total	$ 44	$ —	$ —	$ 2	$ 46
2012					
Insurance contracts	$ 42	$ —	$ 7	$ (5)	$ 44
Total	$ 42	$ —	$ 7	$ (5)	$ 44

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, 2013 and 2012.

Expected Payment of Future Benefits and Employer Contributions . As of December 31, 2013, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2014	$ 191	$ 52
2015	192	51
2016	195	50
2017	195	49
2018	194	48
2019-2023	964	223

(a) Includes a reduction of approximately $3 million in each of the years 2014 - 2018 and approximately $13 million in aggregate for 2019 - 2023 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In January 2014, we contributed $50 million to our pension plan. We expect to contribute approximately $32 million to our OPEB plan in 2014.

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 2013, 2012 and 2011:

	Pension Benefits			OPEB		
	2013	2012	2011	2013	2012	2011
Assumptions related to benefit obligations:						
Discount rate	4.45%	3.40%	4.50%	4.34%	3.34%	4.25%
Rate of compensation increase	3.50%	3.00%	3.50%	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate(a)	3.40%	4.22%	5.50%	3.62%	4.11%	5.00%
Expected return on plan assets(b)(c)	8.00%	8.44%	8.90%	7.35%	8.21%	8.90%
Rate of compensation increase	3.00%	3.50%	3.50%	n/a	n/a	n/a

(a) The discount rate related to pension benefit cost was 4.50% for the period from January 1, 2012 to May 24, 2012, and 4.03% for the period from May 25, 2012 to December 31, 2012 (the period subsequent to the EP acquisition). 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, and 4.25% for the period from January 1, 2012 to May 24, 2012 and 4.01% for the period from May 25, 2012 to December 31, 2012.

(b) The expected return on plan assets related to pension cost was 8.90% for the period from January 1, 2012 to May 24, 2012, and 8.11% for the period from May 25, 2012 to December 31, 2012 (the period subsequent to the EP acquisition). The expected return on plan assets related to other postretirement benefit cost was 8.90% for the period from January 1, 2012 to May 24, 2012, and 7.72% for the period from May 25, 2012 to December 31, 2012.

(c) 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 assumed EP OPEB plans, we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes at a rate of 24% and 22% for 2013 and 2012, respectively.

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 6.57%, gradually decreasing to 5.00% by the year 2019. 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, 2013 and 2012 (in millions):

	2013	2012
One-percentage point increase:		
Aggregate of service cost and interest cost	$ 2	$ 1
Accumulated postretirement benefit obligation	45	52
One-percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(39)	(45)

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 (including amounts associated with the EP Pension and OPEB plans since the May 25, 2012 acquisition date) recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows (in millions):

	Pension Benefits			OPEB		
	2013	2012	2011	2013	2012	2011
Components of net benefit cost:						
Service cost	$ 25	$ 18	$ 13	$ —	$ —	$ —
Interest cost	92	67	17	23	18	4
Expected return on assets	(175)	(110)	(22)	(22)	(15)	(5)
Amortization of prior service (credit) cost	—	(1)	(1)	(1)	(1)	—
Amortization of net actuarial loss	—	10	7	3	4	4
Curtailment and settlement gain	(3)	(2)	—	—	(1)	—
Net benefit (credit) cost	(61)	(18)	14	3	5	3
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net (gain) loss arising during period	(211)	85	46	(50)	25	13
Prior service cost (credit) arising during period	25	(17)	(6)	(18)	(4)	—
Amortization or settlement recognition of net actuarial gain (loss)	3	(10)	(7)	(3)	(5)	(4)
Amortization of prior service credit	—	1	1	1	1	—
Total recognized in total other comprehensive income loss	(183)	59	34	(70)	17	9
Total recognized in net benefit (credit) cost and other comprehensive (income) loss	$ (244)	$ 41	$ 48	$ (67)	$ 22	$ 12

Other Plans

Plans Associated with Foreign Operations

Two of KMP's 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 of KMP also provide postretirement benefits other than pensions for retired employees. KMP's combined net periodic benefit costs for these Trans Mountain pension and other postretirement benefit plans for each of the years ended December 31, 2013, 2012 and 2011 were $11 million, $11 million and $7 million, respectively, recognized ratably over each year. As of December 31, 2013, KMP estimates its overall net periodic pension and other postretirement benefit costs for these plans for the year 2014 will be approximately $11 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, KMP expects to contribute approximately $10 million to these benefit plans in 2014.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily KMP's acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, KMP participates in several multi-employer pension plans for the benefit of employees who are union members. KMP does not administer these plans and contributes 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 $11 million, $11 million and $12 million for the years ended December 31, 2013, 2012 and 2011, respectively. KMP considers its overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

10. Stockholders' Equity

Kinder Morgan, Inc. – Equity Interests

Common Equity

On May 23, 2012, we announced that our board of directors had approved a warrant repurchase program, authorizing us to repurchase in the aggregate up to $250 million of warrants, which repurchase was completed as of May 2013. In the second quarter of 2013, we repurchased an additional $38 million in warrants, which was approved by our board of directors separate and apart from the publicly announced repurchase program. On July 17, 2013, we announced that our board of directors had authorized an additional $350 million share and warrant repurchase program, which repurchase was completed as of December 2013. On October 16, 2013, we announced that our board of directors had approved an additional share and warrant repurchase program authorizing us to repurchase in the aggregate up to $250 million of additional shares or warrants. During December 2013, we repurchased $172 million of our Class P shares. During the years ended December 31, 2013 and 2012, we paid a total of $465 million and $157 million, respectively, for the repurchase of warrants. As of December 31, 2013, $156 million of the October 2013 $250 million repurchase program had been utilized.

The following table sets forth the changes in our outstanding shares during the years ended December 31, 2013 and 2012 and during 2011 since becoming public (see "—Initial Public Offering" following):

	Class P	Class A	Class B	Class C
Balance at February 16, 2011	109,786,590	597,213,410	100,000,000	2,462,927
Shares converted	61,241,023	(61,241,023)	(5,867,404)	(144,669)
Shares canceled	(108,043)	—	—	—
Restricted shares vested	1,570	—	—	—
Balance at December 31, 2011	170,921,140	535,972,387	94,132,596	2,318,258
Shares issued for EP acquisition (see Note 3)	330,154,610	—	—	—
Shares issued with conversions of EP Trust I Preferred securities	562,521	—	—	—
Shares converted	535,972,387	(535,972,387)	(94,132,596)	(2,318,258)
Shares canceled	(2,049,615)	—	—	—
Restricted shares vested	107,553	—	—	—
Balance at December 31, 2012	1,035,668,596	—	—	—
Shares issued for EP acquisition(a)	53			
Shares repurchased and canceled	(5,175,055)			
Shares issued with conversions of EP Trust I Preferred securities	77,442			
Shares issued for exercised warrants	16,886			
Restricted shares vested	89,154			
Balance at December 31, 2013	1,030,677,076			

(a) Represents Class P shares 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.

Share Repurchases Subsequent to December 31, 2013

Subsequent to December 31, 2013, we paid $94 million to repurchase approximately 3 million of our Class P shares effectively completing the October 16, 2013 share and warrant repurchase program.

Initial Public Offering

On February 10, 2011, we converted from a Delaware LLC named Kinder Morgan Holdco LLC to a Delaware corporation named Kinder Morgan, Inc. and our outstanding units were converted into classes of our capital stock. These transactions are referred to herein as the "Conversion Transaction." On February 16, 2011, we completed the initial public offering of our Class P common stock, which is sometimes referred to herein as our "common stock." All of the common stock that was sold in the offering was sold by our existing investors consisting of funds advised by or affiliated with Goldman Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC, referred to herein as the "Sponsor Investors." No members of management sold shares in the offering, and we did not receive any proceeds from the offering.

Upon the completion of our initial public offering of Class P common stock we were owned by the public, and by individuals and entities that were the owners of Kinder Morgan Holdco LLC, which are referred to collectively in this report as the "Investors." The Investors were Richard D. Kinder, our Chairman and Chief Executive Officer; the Sponsor Investors; Fayez Sarofim, one of our directors, and investment entities affiliated with him, and an investment entity affiliated with Michael C. Morgan, another of our directors, and William V. Morgan, one of our founders, whom we refer to collectively as the "Original Stockholders"; and a number of other members of our management, who are referred to collectively as "Other Management."

The Investors owned all of our outstanding Class A shares, Class B shares and Class C shares, which are sometimes referred to in this report as the "investor retained stock." Our Class A shares represented the total capital contributed by the Investors (and a notional amount of capital allocated to the contribution of the holders of the Class C shares) at the time of a 2007 going private transaction. The Class B shares and Class C shares represented incentive compensation that were held by members of our management, including Mr. Kinder only in the case of the Class B shares.

During the year ended December 31, 2012, certain of the Sponsor Investors (the Selling Stockholders) completed underwritten public offerings (the Offerings) of an aggregate of 198,996,921 shares of our Class P common stock (including 8,700,000 shares that were the subject of an underwriters' option to purchase additional shares). Neither we nor our management sold any shares of common stock in the Offerings, and we did not receive any of the proceeds from the Offerings of shares by the Selling Stockholders. As a result of these offerings, the Sponsor Investors advised by or affiliated with Goldman Sachs & Co., The Carlyle Group, and Riverstone Holdings LLC no longer own any of our shares, and representatives of these Sponsor Investors are no longer on our board.

On December 26, 2012, the remaining series of the Class A, Class B and Class C shares held by the Investors automatically converted into shares of Class P common stock upon the election of the holders of at least two-thirds of the shares of each such series of Class A common stock and the holders of at least two-thirds of the shares of each such series of Class B common stock. Subsequent to these conversions, all our Class A, Class B and Class C shares were fully converted and as a result, only our Class P common stock was outstanding as of December 31, 2012. Additionally, as Class A, Class B and Class C shares converted, certain holders of Class P shares were paid out in cash and their Class P shares were immediately canceled. During the years ended December 31, 2012 and 2011, approximately 2 million and less than 1 million, respectively, Class P shares were canceled resulting in payments totaling approximately $71 million and $2 million, respectively, to the holders of those shares.

Dividends

Holders of our common stock share equally 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,		
	2013	**2012**	**2011(a)**
Per common share cash dividend declared for the period	$ 1.60	$ 1.40	$ 1.05
Per common share cash dividend paid in the period	$ 1.56	$ 1.34	$ 0.74

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(a) Represents dividends subsequent to the initial public offering.

On February 11, 2011, our board of directors declared and paid a distribution to our then existing investors of $246 million with respect to the period for which we were not public. This consisted of $205 million for the fourth quarter of 2010 and $105 million for the first 46 days of 2011, representing the portion of the first quarter of 2011 that we were not public, less a one-time adjustment of $64 million in available earnings and profits reserved for the after tax cost of special cash bonuses (and premium pay) in an aggregate amount of approximately $100 million that was paid in May of 2011 to certain of our non-senior management employees. No holders of our Class B shares or Class C shares received such bonuses.

Dividends Subsequent to December 31, 2013

On January 15, 2014, our board of directors declared a cash dividend of $0.41 per share for the quarterly period ended December 31, 2013. This dividend was paid on February 18, 2014 to shareholders of record as of January 31, 2014. Since this dividend was declared after the end of the quarter, no amount is shown in our accompanying December 31, 2013 consolidated balance sheet as a dividend payable.

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 during 2013 and 2012.

	Warrants	
	2013	**2012**
Beginning balance	439,809,442	—
Warrants issued in EP acquisition(a)	81	504,598,883
Warrants issued with conversions of EP Trust I Preferred securities(b)	118,377	859,796
Warrants exercised	(21,208)	—
Warrants repurchased and canceled	(91,973,585)	(65,649,237)
Ending balance	347,933,107	439,809,442

(a) See Note 3. 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 8.

Noncontrolling Interests

The caption "Noncontrolling interests" in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2013	**2012**
KMP	$ 7,642	$ 3,270
EPB	4,122	4,111
KMR	3,142	2,716
Other	286	137
	$ 15,192	$ 10,234

At December 31, 2013, we owned, directly, and indirectly in the form of i-units corresponding to the number of shares of KMR we owned, approximately 43 million limited partner units of KMP. These units, which consist of 22 million common units, 5 million Class B units and 16 million i-units, represent approximately 9.8% of the total outstanding limited partner interests of KMP. In addition, we indirectly own all the common equity of the general partner of KMP, which holds an effective 2% interest in KMP and its operating partnerships. Together, at December 31, 2013, our limited partner and general partner interests represented approximately 11.6% of KMP's total equity interests and represented an approximate 50% economic interest in KMP. This difference results from the existence of incentive distribution rights (IDRs) held by KMGP, the general partner of KMP.

As of December 31, 2013, we owned approximately 90 million limited partner units of EPB, representing approximately 41% of the total equity interests of EPB. In addition, we are the sole owner of the general partner of EPB, which holds an effective 2% interest in EPB, including all of EPB's IDRs.

At December 31, 2013, we owned approximately 16 million KMR shares representing approximately 13.0% of KMR's outstanding shares.

Contributions

Contributions from our noncontrolling interests consist primarily of equity issuances by KMP, EPB and KMR. As of December 31, 2013, each of these subsidiaries has an equity distribution agreement in place which allows the subsidiary to sell its equity interests from time to time through a designated sales agent. The terms of each agreement are substantially similar. Sales of the subsidiary's equity interests will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between the subsidiary equity issuer and its sales agent. The subsidiary equity issuer may also sell its equity interests to its sales agent as principal for the sales agent's own account at a price agreed upon at the time of the sale. Any sale of the subsidiary's equity interests to the sales agent as principal would be pursuant to the terms of a separate agreement between the subsidiary equity issuer and its sales agent. The equity distribution agreement provides 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. The subsidiary retains at all times complete control over the amount and the timing of sales under its respective equity distribution agreement, and it will designate the maximum number of equity units or shares to be sold through its sales agent, on a daily basis or otherwise as the subsidiary equity issuer and its sales agent agree.

The table below shows significant issuances to the public of common units or shares, the net proceeds from the issuances and the use of the proceeds during the years ended December 31, 2013 and 2012 by KMP, EPB and KMR (dollars in millions and shares in thousands).

Issuances	Common units/shares	Net proceeds		Use of proceeds
	(in thousands)	(in millions)		
KMP				
Issued under Equity Distribution Agreement(a)				
2013	10,814	$ 900		Reduced borrowings under KMP's commercial paper program
2012	6,933	$ 560		Reduced borrowings under KMP's commercial paper program
Other issuances				
February 2013	4,600	$ 385		Issued to pay a portion of the purchase price for the March 2013 drop-down transaction
May 2013	43,371	$ —	(b)	Issued to Copano unitholders as KMP's purchase price for Copano
June 2012	3,792	$ —	(c)	Issued as KMP's purchase price for the 50% equity ownership interest in EP midstream assets it acquired from KKR
December 2012(d)	4,485	$ 349		Reduced borrowings under KMP's commercial paper program
EPB				
Issued under Equity Distribution Agreement(e)				
2013	2,038	$ 85	(f)	General partnership purposes
Other issuances				
September 2012(d)	8,165	$ 272	(g)	Repayment of CPG debt, certain EPB short-term debt and general partnership purposes
KMR				
Issued under Equity Distribution Agreement(h)				
2013	2,640	$ 210		Purchased additional KMP i-units; KMP then used proceeds to reduce borrowings under its commercial paper program
September 2012	10,120	$ 727		Purchased additional KMP i-units; KMP then used proceeds for a portion of the purchase price of the August 2012 drop-down transaction

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(a) On June 3, 2013, KMP entered into a fourth amended and restated equity distribution agreement with UBS Securities LLC (UBS) which increased the aggregate offering price of KMP's common units to up to $2.175 billion (up from $1.9 billion), and on August 7, 2013, KMP entered into a second and separate equity distribution agreement with UBS. The terms of this new equity distribution agreement are substantially similar to those in KMP's previous agreement, and it allows KMP to offer and sell from time to time additional KMP common units having an aggregate offering price of up to $1.9 billion through UBS, as sales agent. On February 27, 2012, KMP entered into a third amended and restated equity distribution agreement with UBS which increased the aggregate offering price of its common units to up to $1.9 billion (up from $1.2 billion).

(b) KMP valued these units at $3,733 million based on the $86.08 closing market price of a KMP common unit on the NYSE on May 1, 2013.

(c) See Note 3.

(d) Includes the underwriters' exercise of the overallotment option.
(e) On March 7, 2013, EPB entered into an equity distribution agreement with Global Markets, Inc. (Citigroup). Pursuant to the provisions of EPB's equity distribution agreement, EPB may sell from time to time through Citigroup, as its sales agent, EPB's common units representing limited partner interests having an aggregate offering price of up to $500 million.
(f) Represents proceeds received from noncontrolling interests and excludes our $2 million contribution as the owner of EPB's general partner.
(g) Represents proceeds received from noncontrolling interests and excludes our $7 million contribution as the owner of EPB's general partner.
(h) On May 4, 2012, KMR entered into an equity distribution agreement with Credit Suisse Securities (USA) LLC (Credit Suisse). Pursuant to the provisions of KMR's equity distribution agreement, it may sell from time to time through Credit Suisse, as its sales agent, KMR shares having an aggregate offering price of up to $500 million.

The above equity issuances by KMP, EPB and KMR during the years ended December 31, 2013 and 2012 had the associated effects of increasing our (i) noncontrolling interests by $5,059 million and $2,112 million, respectively; (ii) accumulated deferred income taxes by $93 million and $38 million, respectively; and (iii) additional paid-in capital by $161 million and $64 million, respectively.

Contributions Subsequent to December 31, 2013

Shares and units issued subsequent to December 31, 2013 include (i) 76,100 of KMR's shares; and (ii) 198,110 of KMP's common units both of which were issued in early January for the settlement of sales made on or before December 31, 2013 pursuant to KMR and KMP's respective equity distribution agreements. KMR and KMP received net proceeds of $16 million and $6 million, respectively, for the issuance of these shares and common units and the combined proceeds were used to reduce borrowings under KMP's commercial paper program.

On February 19, 2014, KMP priced in a public offering, 7,935,000 of its common units (including the exercise of the underwriters' overallotment option) at a price of $78.32 per unit, less commissions and underwriting expenses.

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,		
	2013	**2012**	**2011**
KMP			
Per unit cash distribution declared for the period	$ 5.33	$ 4.98	$ 4.61
Per unit cash distribution paid in the period	$ 5.26	$ 4.85	$ 4.58
Cash distributions paid in the period to the public	$ 1,372	$ 1,081	$ 955
EPB(a)			
Per unit cash distribution declared for the period	$ 2.55	$ 1.74	n/a
Per unit cash distribution paid in the period	$ 2.51	$ 1.13	n/a
Cash distributions paid in the period to the public	$ 318	$ 137	n/a
KMR(b)			
Share distributions paid in the period to the public	6,588,477	5,586,579	5,659,507

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(a) Represents distribution information since the May 2012 EP acquisition.
(b) KMR's distributions are 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 976,723, 902,367 and 941,895 of shares distributed in 2013, 2012 and 2011, respectively, on KMR shares we directly and indirectly own. On February 14, 2014, KMR paid a share distribution of 0.017841 shares per outstanding share (2,237,258 total shares) to shareholders of record as of January 31, 2014, based on the $1.36 per common unit distribution declared by KMP, of which 1,952,970 shares were distributed to the public.

KMP Distributions

KMP's partnership agreement requires that it distribute 100% of "Available Cash," as defined in its partnership agreement, to its partners within 45 days following the end of each calendar quarter. Available Cash consists generally of all of KMP's cash receipts, including cash received by its operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to its noncontrolling interests.

KMR, as the delegate of KMGP, of which we indirectly own all of the outstanding common equity, and the general partner of KMP, is granted discretion, subject to the approval of KMGP in certain cases, to establish, maintain and adjust reserves for the proper conduct of KMP's business, which might include reserves for matters such as future operating expenses, debt service, sustaining capital expenditures and rate refunds, and for distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When KMR determines KMP's quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Pursuant to KMP's partnership agreement, distributions to its unitholders are characterized either as distributions of cash from operations or as distributions of cash from interim capital transactions. This distinction affects the distributions to owners of common units, Class B units and i-units relative to the distributions retained by KMGP as KMP's general partner.

Cash from Operations. Cash from operations generally refers to KMP's cash balance on the date it commenced operations, plus all cash generated by the operation of its business, after deducting related cash expenditures (including capital expenditures other than expansion capital expenditures), net additions to or reductions in reserves, debt service and various other items.

Cash from Interim Capital Transactions. Cash from interim capital transactions will generally result only from distributions that are funded from borrowings, sales of debt and equity securities and sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets and assets disposed of in the ordinary course of business.

Rule for Characterizing Distributions. Generally, all available cash distributed by KMP from any source will be treated as distributions of cash from operations until the sum of all available cash distributed equals the cumulative amount of cash from operations actually generated from the date KMP commenced operations through the end of the calendar quarter prior to that distribution. Any distribution of available cash which, when added to the sum of all prior distributions, is in excess of the cumulative amount of cash from operations, will be considered a distribution of cash from interim capital transactions until the initial common unit price is fully recovered as described below under "—Allocation of Distributions from Interim Capital Transactions." For purposes of calculating the sum of all distributions of available cash, the total equivalent cash amount of all distributions of i-units to KMR, as the holder of all i-units, will be treated as distributions of available cash, even though the distributions to KMR are made in additional i-units rather than cash and KMP retains this cash and uses it in its business. To date, all of KMP's available cash distributions, other than a $177 million distribution of cash from interim capital transactions in 2010, have been treated as distributions of cash from operations.

Allocation of Distributions from Operations. Cash from operations for each quarter will be distributed effectively as follows:

		Marginal percentage interest in distribution	
	Total quarterly distribution per unit target amount	**Unitholders**	**General partner**
First target distribution	$0.15125	98%	2%
Second target distribution	above $0.15125 up to $0.17875	85%	15%
Third target distribution	above $0.17875 up to $0.23375	75%	25%
Thereafter	above $0.23375	50%	50%

Allocation of Distributions from Interim Capital Transactions. Any distribution by KMP of available cash that would constitute cash from interim capital transactions would be distributed effectively as follows:

- 98% to all owners of common units and Class B units pro rata in cash and to the holder of i-units in equivalent i-units; and

- 2% to KMGP, as KMP's general partner, until KMP has distributed cash from this source in respect of a common unit outstanding since KMP's original public offering in an aggregate amount per unit equal to the initial common unit price of $5.75, as adjusted for splits.

As cash from interim capital transactions is distributed, it would be treated as if it were a repayment of the initial public offering price of the common units. To reflect that repayment, the first three distribution target levels of cash from operations (described above) would be adjusted downward proportionately by multiplying each distribution target level amount by a fraction, the numerator of which is the unrecovered initial common unit price immediately after giving effect to that distribution and the denominator of which is the unrecovered initial common unit price immediately prior to giving effect to that distribution. When the initial common unit price is fully recovered, then each of the first three distribution target levels will have been reduced to zero and thereafter, all distributions of available cash from all sources will be treated as if they were cash from operations and available cash will be distributed 50% to all classes of units pro rata (with the distribution to i-units being made instead in the form of i-units), and 50% to KMGP as KMP's general partner. With respect to the portion of our distribution of available cash for 2010 that was from interim capital transactions, KMGP, as KMP's general partner, waived this resetting of the distribution target levels.

Distributions paid by KMP to KMGP during 2013 were reduced by a waived incentive amount of $50 million related to common units issued to finance KMP's May 2013 Copano acquisition. Beginning with KMP's distribution payments for the quarterly period ended June 30, 2013, and ending with its distribution payments for the quarterly period ended March 31, 2038, KMGP, as KMP's general partner, agreed not to take certain incentive distributions related to KMP's acquisition of Copano. For more information about KMP's May 2013 Copano acquisition, see Note 3. In addition, distributions paid by KMP to KMGP during 2013, 2012 and 2011 were reduced by waived incentive amounts equal to $11 million, $27 million and $28 million, respectively, related to common units issued to finance a portion of KMP's May 2010 and July 2011 KinderHawk acquisitions. Beginning with KMP's distribution payments for the quarterly period ended June 30, 2010, and ending with its distribution payments for the quarterly period ended March 31, 2013, KMGP, as KMP's general partner, has agreed not to take certain incentive distributions related to KMP's acquisition of KinderHawk. For more information about KMP's July 2011 KinderHawk acquisition, see Note 3.

EPB Distributions

Incentive Distribution Rights. El Paso Pipeline GP Company, L.L.C., as the general partner of EPB and the holder of EPB's IDRs, has the right under EPB's partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and (upon satisfaction of certain conditions) to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to El Paso Pipeline GP Company, L.L.C., as EPB's general partner, would be set. In connection with this election, El Paso Pipeline GP Company, L.L.C. , as EPB's general partner, would be entitled to receive a number of newly issued Class B common units and general partner units based on a predetermined formula. Although the conditions have been met to entitle El Paso Pipeline GP Company, L.L.C. to elect to reset the minimum quarterly distribution amount and the target distribution levels, no such election has been made.

El Paso Pipeline GP Company, L.L.C. currently holds all of EPB's IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in EPB's partnership agreement.

Income Allocation and Declared Distributions. For the purposes of maintaining partner capital accounts, EPB's partnership agreement specifies that items of income and loss shall be allocated among the partners in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to El Paso Pipeline GP Company, L.L.C., as the holder of EPB's IDRs. Incentive distributions are generally defined as all cash distributions paid to El Paso Pipeline GP Company, L.L.C., as EPB's general partner, that are in excess of 2% of the aggregate value of cash distributions made to all partners.

EPB's partnership agreement requires that it distribute all of its available cash from operating surplus each quarter. EPB determines the allocation of incentive distributions to El Paso Pipeline GP Company, L.L.C., as EPB's general partner, by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of EPB's partnership agreement summarized in the table below. The percentage interests set forth below for El Paso Pipeline GP Company, L.L.C., as EPB's general partner, include its 2% general partner interest and assume El Paso Pipeline GP Company, L.L.C. has contributed any additional capital necessary to maintain its 2% general partner interest and has not transferred its IDRs.

	Total quarterly distribution per unit target amount	Marginal percentage interest in distributions	
		Unitholders	General partner
Minimum quarterly distribution	$0.2875	98%	2%
First target distribution	above $0.2875 up to $0.33063	98%	2%
Second target distribution	above $0.33063 up to $0.35938	85%	15%
Third target distribution	above $0.35938 up to $0.43125	75%	25%
Thereafter	above $0.43125	50%	50%

Distributions Subsequent to December 31, 2013

On January 15, 2014, KMP declared a cash distribution of $1.36 per unit for the quarterly period ended December 31, 2013. The distribution was paid on February 14, 2014 to KMP's unitholders of record as of January 31, 2014, of which $445 million was paid to the public holders (represented in noncontrolling interests). Related to this February 14, 2014 distribution, KMGP, waived an incentive distribution amount equal to $25 million to support KMP's May 2013 Copano acquisition.

On January 15, 2014, EPB declared a cash distribution of $0.65 per unit for the quarterly period ended December 31, 2013. The distribution was paid on February 14, 2014 to EPB's unitholders of record as of January 31, 2014.

11. Related Party Transactions

Affiliated Balances

The following table summarizes our balance sheet affiliate balances (in millions):

	Year Ended December 31,	
	2013	2012
Balance sheet location		
Accounts receivable, net	$ 19	$ 25
Assets held for sale(a)	—	114
Other current assets	3	14
Deferred charges and other assets	47	48
	$ 69	$ 201
Current portion of debt – KMP and EPB(b)	$ 6	$ 5
Accounts payable	9	11
Long-term debt - Outstanding - KMP and EPB(b)	169	173
	$ 184	$ 189

(a) 2012 amount related to KMP's equity investment in the Express pipeline system (see Note 2).
(b) EPB has financing obligations payable to WYCO.

Notes Receivable

Plantation

KMP and ExxonMobil have a term loan agreement covering a note receivable due from Plantation. KMP owns a 51.17% equity interest in Plantation and KMP's proportionate share of the outstanding principal amount of the note receivable was $48 million as of December 31, 2013 and $49 million as of December 31, 2012. 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 of $45 million (for KMP's portion of the note) due on July 20, 2016. We included $1 million of the note receivable balance within "Other current assets" on our accompanying consolidated balance sheets as of both December 31, 2013 and December 31, 2012, and we included the remaining outstanding balance within " Deferred charges and other assets."

Express US Holdings LP

As discussed in Note 3 "Acquisitions and Divestitures—Divestitures—Express Pipeline System," KMP sold both its 33 1/3% equity ownership interest in the Express pipeline system and a subordinated debenture investment in Express to Spectra Energy Corp. effective March 14, 2013. KMP's long-term debt investment consisted of a C$114 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintained ownership of the U.S. portion of the Express pipeline system. The debenture was denominated in Canadian dollars, bore interest at a rate of 12.0% per annum, and was due in full on January 9, 2023. As of December 31, 2012 the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $114 million. Since KMP had entered into a definitive agreement to sell its debt investment in Express as of this date, we included this note balance within "Assets held for sale" on our accompanying consolidated balance sheet as of that date.

Gulf LNG Holdings Group, LLC

In conjunction with the acquisition of EP, KMI acquired a long-term note receivable, bearing interest at 12% per annum, that was due from Gulf LNG Holdings Group, LLC, a 50% equity investee, with a remaining principal amount of $85 million. Subsequent to the EP acquisition and through the end of 2012, we received payments on this note totaling $75 million. We received payments for the remaining note balance of $10 million during the first quarter of 2013. The balance of $10 million at December 31, 2012 was included in our accompanying consolidated balance sheet within "Other current assets."

Subsequent Event

On February 4, 2014, KMP entered into a loan agreement with Midcontinent Express Pipeline LLC, KMP's 50%-owned equity investee. The loan agreement allows KMP, at their sole option, to make loans from time to time to Midcontinent Express to fund its working capital needs and for other limited liability company 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. All loans mature on February 3, 2015, however, the loan agreement includes renewal provisions for one or more additional one-year terms if approved by both parties. Borrowings under the loan agreement bear interest at a rate per annum equal to LIBOR plus 1.5875%, and all borrowings can be prepaid before maturity without penalty or premium. As of the date of this report, there was no amount outstanding pursuant to this loan agreement.

12. Commitments and Contingent Liabilities

Leases

The table below depicts future gross minimum rental commitments under our operating leases as of December 31, 2013 (in millions):

Year	Commitment	
2014	$	70
2015		59
2016		50
2017		39
2018		37
Thereafter		177
Total minimum payments	$	432

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to forty. Total lease and rental expenses were $126 million, $94 million and $146 million for each of the years ended December 31, 2013, 2012 and 2011, respectively. The increase in our lease and rental expenses in 2011 compared to 2013 and 2012 was driven by a $70 million increase in expense in 2011 associated with adjustments to KMP's Pacific operations' rights-of-way liabilities. The amount of capital leases included within "Property, plant and equipment, net" in our accompanying consolidated balance sheets as of December 31, 2013 and 2012 are not material to our consolidated balance sheets.

Commitments

Capital Contributions for Elba Island Liquefaction Project

In January 2013, SLC, a subsidiary of EPB, and Shell US Gas and Power, LLC (Shell G&P), a subsidiary of Royal Dutch Shell plc (Shell), formed ELC, EPB's equity method investment, to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal. In connection with the formation of ELC, SLC and Shell G&P entered into a LLC agreement in which SLC owns 51% of ELC and Shell G&P owns the remaining membership interest. Under the terms of the LLC agreement, SLC and Shell G&P are both obligated to make certain capital contributions in proportion to their membership interests in ELC to fund the construction of the liquefaction facilities. EPB's investment at the terminal in Phase I, including both the liquefaction facilities and SLNG ancillary facilities, is estimated to be approximately $800 million . Phase I of the project requires no additional Department of Energy (DOE) approval.

Contingent Debt

KMP's contingent debt disclosures pertain to certain types of guarantees or indemnifications KMP has made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring KMP's performance under such guarantee is remote. As of December 31, 2013 and 2012, KMP's contingent debt obligations, as well as KMP's obligations with respect to related letters of credit, totaled $74 million and $86 million, respectively. This amount is primarily related to the debt obligations of KMP's 50%-owned investee, Cortez Pipeline Company (KMP is severally liable for its percentage ownership share (50%) of the Cortez Pipeline Company debt).

Contingent Lease Liabilities

KMP has agreed to guarantee certain lease payments from 2014 through 2035 made by us to EPC Building, LLC, a wholly owned subsidiary of KMI, related to our principal executive offices located at 1001 Louisiana Street in Houston, Texas. KMP would be required to perform under this guarantee only if we were unable to perform. During the term of this lease, the payments KMP guarantees increase from $27 million in 2014 to $38 million in 2035.

KMI Guarantee of KMP and EPB Debt

In conjunction with KMP's acquisition of certain natural gas pipelines from us, we agreed to indemnify KMP with respect to approximately $5.9 billion of its debt. This indemnification primarily includes $5.2 billion associated with KMP's August 2012 purchase of TGP and the purchase of EPNG and EP Midstream assets through both the August 2012 and the March 2013 drop-down transactions. In conjunction with our EP acquisition, we have agreed to indemnify EPB with respect to $470 million of its debt. We would be obligated to perform under these indemnities only if KMP's or EPB's assets, as applicable, were unable to satisfy its obligations.

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.

Our potential exposure under guarantee and indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Those arrangements with a specified dollar amount have a maximum stated value of approximately $814 million, which primarily represents indemnification agreements that we assumed in the EP acquisition associated with EP's prior discontinued and foreign operations. 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.

For additional information regarding our, KMP's and EPB's debt facilities see Note 8.

13. 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 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.

As part of the EP acquisition, we acquired power forward and swap contracts. We have entered into offsetting positions that eliminate the price risks associated with our power contracts. As part of the May 1, 2013 Copano acquisition, KMP acquired derivative contracts related to natural gas, NGL and crude oil. None of these derivatives are designated as accounting hedges.

Energy Commodity Price Risk Management

As of December 31, 2013, KMP and KMI had entered into the following outstanding commodity forward contracts to hedge their forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil fixed price	(22.6) MMBbl
Natural gas fixed price	(19.8) Bcf
Natural gas basis	(18.9) Bcf
Derivatives not designated as hedging contracts	
Crude oil fixed price	(0.9) MMBbl
Natural gas fixed price	(17.3) Bcf
Natural gas basis	(8.2) Bcf
NGL fixed price	(1.1) MMBbl

As of December 31, 2013, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2017.

Interest Rate Risk Management

As of December 31, 2013, KMI and KMP had a combined notional principal amount of $725 million and $4,675 million, respectively, of fixed-to-variable interest rate swap agreements, effectively converting 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. All of KMI and KMP 's swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of December 31, 2013, 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 June 2013, KMP terminated three of their existing fixed-to-variable interest rate swap agreements in separate transactions. These swap agreements had a combined notional principal amount of $975 million, and received combined proceeds of $96 million from the early termination of these swap agreements. In August 2013, KMP entered into six separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $500 million. Four of these agreements effectively convert a portion of the interest expense associated with KMP's 2.65% senior notes due February 1, 2019 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread and the remaining two agreements effectively convert a portion of the interest expense associated with KMP's 4.15% senior notes due February 1, 2024, from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread. In December 2013, three separate fixed-to-variable interest rate swap agreements having a combined notional amount of $375 million associated with KMP's 5.00% senior notes terminated upon the maturing of the associated notes.

As of December 31, 2012, KMI and KMP each had a combined notional principal amount of $725 million and $5,525 million, respectively, of fixed-to-variable interest rate swap agreements.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of December 31, 2013 and 2012 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		December 31,		December 31,	
		2013	2012	2013	2012
	Balance sheet location	Fair value		Fair value	
Derivatives designated as hedging contracts					
Natural gas and crude derivative contracts	Other current assets/(Other current liabilities)	$ 18	$ 42	$ (33)	$ (18)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	58	40	(30)	(11)
Subtotal		76	82	(63)	(29)
Interest rate swap agreements	Other current assets/(Other current liabilities)	87	9	—	—
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	172	656	(116)	(1)
Subtotal		259	665	(116)	(1)
Total		335	747	(179)	(30)
Derivatives not designated as hedging contracts					
Natural gas, crude and NGL derivative contracts	Other current assets/(Other current liabilities)	4	4	(5)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	—	(1)
Subtotal		4	4	(5)	(4)
Power derivative contracts	Other current assets/(Other current liabilities)	7	8	(54)	(59)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	11	13	(73)	(120)
Subtotal		18	21	(127)	(179)
Total		22	25	(132)	(183)
Total derivatives		$ 357	$ 772	$ (311)	$ (213)

Certain of our derivative contracts are subject to master netting agreements. As of December 31, 2013 and 2012, we presented the fair value of our derivative contracts on a gross basis on our accompanying consolidated balance sheets. The following tables present our derivative contracts subject to such netting agreements as of the dates indicated (in millions):

Offsetting of Financial Assets and Derivative Assets

	Gross amounts of recognized assets	Gross amounts offset in the balance sheet	Amounts of assets presented in the balance sheet	Gross amounts not offset in the balance sheet		Net amount
				Financial instruments	Cash collateral held(a)	
As of December 31, 2013:						
Natural gas, crude and NGL derivative contracts	$ 80	$ —	$ 80	$ (44)	$ —	$ 36
Power derivative contracts	$ 18	$ —	$ 18	$ (18)	$ —	$ —
Interest rate swap agreements	$ 259	$ —	$ 259	$ (28)	$ —	$ 231
As of December 31, 2012:						
Natural gas, crude and NGL derivative contracts	$ 86	$ —	$ 86	$ (17)	$ —	$ 69
Power derivative contracts	$ 21	$ —	$ 21	$ (21)	$ —	$ —
Interest rate swap agreements	$ 665	$ —	$ 665	$ —	$ —	$ 665

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross amounts of recognized liabilities	Gross amounts offset in the balance sheet	Amounts of liabilities presented in the balance sheet	Gross amounts not offset in the balance sheet		Net amount
				Financial instruments	Cash collateral posted(b)	
As of December 31, 2013:						
Natural gas, crude and NGL derivative contracts	$ (68)	$ —	$ (68)	$ 44	$ 17	$ (7)
Power derivative contracts	$ (127)	$ —	$ (127)	$ 18	$ —	$ (109)
Interest rate swap agreements	$ (116)	$ —	$ (116)	$ 28	$ —	$ (88)
As of December 31, 2012:						
Natural gas, crude and NGL derivative contracts	$ (33)	$ —	$ (33)	$ 17	$ 5	$ (11)
Power derivative contracts	$ (179)	$ —	$ (179)	$ 21	$ —	$ (158)
Interest rate swap agreements	$ (1)	$ —	$ (1)	$ —	$ —	$ (1)

(a) Cash margin deposits held by KMP associated with its energy commodity contract positions and OTC swap agreements and reported within "Other current liabilities" in our accompanying consolidated balance sheets.

(b) $17 million and $5 million of cash margin deposits posted by KMP at December 31, 2013 and December 31, 2012, respectively, associated with energy commodity contract positions and OTC swap agreements and reported within "Other current assets" in our accompanying consolidated balance sheets.

Debt Fair Value Adjustments

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Debt fair value adjustments" on our accompanying consolidated balance sheets. Our "Debt fair value adjustments" also include all unamortized debt discount/premium amounts, purchase accounting on our debt balances, and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of December 31, 2013 and 2012, these fair value adjustments to our debt balances included (i) $1,379 million and $1,470 million, respectively, associated with fair value adjustments to our debt previously recorded in purchase accounting; (ii) $143 million and $664 million, respectively, associated with the offsetting entry for hedged debt; (iii) $517 million and $490 million respectively, associated with unamortized premium from the termination of interest rate swap agreements; and offset by (iv) $62 million and $33 million, respectively, associated with unamortized debt discount amounts. As of December 31, 2013, the weighted-average amortization period of the unamortized premium from the termination of the interest rate swaps was approximately 16 years.

Effect of Derivative Contracts on the Income Statement

The following two tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the years ended December 31, 2013, 2012 and 2011 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss)recognized in income on derivatives	Amount of gain/(loss)recognized in income on derivatives and related hedged item(a)		
		Year Ended December 31,		
		2013	2012	2011
Interest rate swap agreements	Interest expense	$ (425)	$ 55	$ 545
Total		$ (425)	$ 55	$ 545
Fixed rate debt	Interest expense	$ 425	$ (55)	$ (545)
Total		$ 425	$ (55)	$ (545)

(a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt, which exactly offset each other as a result of no hedge ineffectiveness.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)(a)			Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)			Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of 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,		
	2013	2012	2011		2013	2012	2011		2013	2012	2011
Energy commodity derivative contracts	$ (45)	$ 87	$ 13	Revenues—Natural gas sales	$ —	$ 4	$ 2	Revenues—Natural gas sales	$ —	$ —	$ —
				Revenues—Product sales and other	(13)	(15)	(193)	Revenues—Product sales and other	3	(11)	5
				Costs of sales	—	17	7	Costs of sales	—	—	—
Interest rate swap agreements	7	(5)	—	Interest expense	2	2	—	Interest expense	—	—	—
Total	$ (38)	$ 82	$ 13	Total	$ (11)	$ 8	$ (184)	Total	$ 3	$ (11)	$ 5

(a) We expect to reclassify an approximate $1 million loss associated with energy commodity price risk management activities and included in our accumulated other comprehensive loss and noncontrolling interest balances as of December 31, 2013 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).

For the years ended December 31, 2013 and 2012, we recognized losses of $10 million and $4 million, respectively, in income and included these amounts within "Revenues-Product sales and other" from derivative contracts not designated as accounting hedges. For the year ended December 31, 2011, such amounts were not significant.

Credit Risks

We and our subsidiary, KMP, have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies, natural gas and electric utilities and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our OTC swaps and options are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of both December 31, 2013 and 2012, KMP had no outstanding letters of credit supporting its hedging of energy commodity price risks associated with the sale of natural gas, NGL and crude oil. As of December 31, 2013 and 2012, KMI had $167 million and $300 million, respectively, of outstanding letters of credit supporting its commodity price risks associated with the sale of natural gas and power.

KMP and KMI also have agreements with certain counterparties to their derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in their credit rating. As of December 31, 2013, we estimate that if KMP's credit rating was downgraded one notch, KMP would be required to post no additional collateral to its counterparties. If KMP was downgraded two notches (that is below investment grade), KMP would be required to post $8 million of additional collateral. As of December 31, 2013, we estimate that if KMI's credit rating was downgraded one or two notches, KMI would be required to post no additional collateral to its counterparties.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

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" for the year ended December 31, 2013 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 income/(loss)
Balance as of December 31, 2012	$ 7	$ 51	$ (176)	$ (118)
Other comprehensive (loss) income before reclassifications	(14)	(49)	151	88
Amounts reclassified from accumulated other comprehensive income	4	—	2	6
Net current-period other comprehensive (loss) income	(10)	(49)	153	94
Balance as of December 31, 2013	$ (3)	$ 2	$ (23)	$ (24)

14. 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 and (ii) interest rate swap agreements as of December 31, 2013 and 2012, based on the three levels established by the Codification. The fair value measurements in the tables below do not include cash margin deposits made by us, which are reported within "Other current assets" in our accompanying consolidated balance sheets (in millions).

	Asset fair value measurements using			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of December 31, 2013				
Energy commodity derivative contracts(a)	$ 98	$ 4	$ 46	$ 48
Interest rate swap agreements	$ 259	$ —	$ 259	$ —
As of December 31, 2012				
Energy commodity derivative contracts(a)	$ 107	$ 3	$ 76	$ 28
Interest rate swap agreements	$ 665	$ —	$ 665	$ —

	Liability fair value measurements using			
	Total	Quoted prices in active markets for identical liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of December 31, 2013				
Energy commodity derivative contracts(a)	$ (195)	$ (6)	$ (31)	$ (158)
Interest rate swap agreements	$ (116)	$ —	$ (116)	$ —
As of December 31, 2012				
Energy commodity derivative contracts(a)	$ (212)	$ (3)	$ (26)	$ (183)
Interest rate swap agreements	$ (1)	$ —	$ (1)	$ —

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of WTI options, NGL options and power derivative contracts.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the years ended December 31, 2013 and 2012 (in millions):

Significant unobservable inputs (Level 3)

	Year Ended December 31,	
	2013	2012
Derivatives-net asset (liability)		
Beginning of period	$ (155)	$ 7
Total gains or (losses)		
Included in earnings	(5)	(4)
Included in other comprehensive income	(1)	(1)
Purchases (a)	17	(194)
Settlements	34	37
End of period	$ (110)	$ (155)
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	$ (8)	$ (2)

(a) 2012 purchases include a net liability of $197 million of Level 3 energy commodity derivative contracts associated with the EP acquisition. 2013 purchases include a net asset of $18 million of Level 3 energy commodity derivative contracts assumed in conjunction with KMP's May 1, 2013 Copano acquisition.

As of December 31, 2013, our Level 3 derivative assets and liabilities consisted primarily of WTI options, NGL options and 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.

The significant unobservable inputs used in the fair value measurement of our power-related derivatives are illiquid pricing points. As the delivery points in our power contracts are in an illiquid market and not actively traded, we adjust the Pennsylvania-New Jersey-Maryland (PJM) forward curves by the difference between the 12-month rolling average of actual settled prices at delivery points in the PJM East region. As of December 31, 2012, the adjusted prices over the contract term ranged from $28.50 per MW/h to $57.32 per MW/h. However, we have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts. Significant increases (decreases) in these inputs in isolation would result in a significantly lower (higher) fair value measurement.

Fair Value of Financial Instruments

The estimated fair value of our outstanding debt balance (both short-term and long-term and including debt fair value adjustments), is disclosed below (in millions):

	December 31, 2013		December 31, 2012	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$ 36,193	$ 36,248	$ 34,401	$ 36,720

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2013 and 2012.

15. 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 sale, transport, processing, treating, fractionation, storage and gathering of natural gas and NGL;

- CO_2—KMP—the production, sale and transportation of crude oil from fields in the Permian Basin of West Texas and the production, transportation and marketing of CO_2 used as a flooding medium for recovering crude oil from mature oil fields;
- Products Pipelines—KMP— the transportation and terminaling of refined petroleum products (including gasoline, diesel fuel and jet fuel) NGL, crude and condensate, and bio-fuels;
- Terminals—KMP—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals;
- Kinder Morgan Canada—KMP—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington. As further described in Note 3, Kinder Morgan Canada divested its interest in the Express pipeline system effective March 14, 2013; and
- Other—primarily includes several physical natural gas contracts with power plants associated with EP's legacy trading activities. These contracts obligate EP to sell natural gas to these plants and have various expiration dates ranging from 2012 to 2028.

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.

Because KMP's and EPB's partnership agreements require them to distribute 100% of their available cash to their partners on a quarterly basis (available cash consists primarily of all cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our segments that are also 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 2013, 2012 and 2011, 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,		
	2013	2012	2011
Revenues			
Natural Gas Pipelines(a)			
Revenues from external customers	$ 8,613	$ 5,230	$ 3,943
Intersegment revenues	4	—	—
CO_2—KMP	1,857	1,677	1,434
Products Pipelines—KMP	1,853	1,370	914
Terminals—KMP			
Revenues from external customers	1,408	1,356	1,314
Intersegment revenues	2	3	1
Kinder Morgan Canada—KMP	302	311	302
Other	1	(6)	—
Total segment revenues	14,040	9,941	7,908
Other revenues(b)	36	35	36
Less: Total intersegment revenues	(6)	(3)	(1)
Total consolidated revenues	$ 14,070	$ 9,973	$ 7,943

	Year Ended December 31,		
	2013	2012	2011
Operating expenses(c)			
Natural Gas Pipelines(a)	$ 5,235	$ 3,111	$ 3,370
CO_2—KMP	439	381	342
Products Pipelines—KMP	1,295	759	500
Terminals—KMP	657	685	634
Kinder Morgan Canada—KMP	110	103	97
Other	30	5	—
Total segment operating expenses	7,766	5,044	4,943
Other operating expenses	—	4	1
Less: Total intersegment operating expenses	(6)	(3)	(1)
Total consolidated operating expenses	$ 7,760	$ 5,045	$ 4,943

	Year Ended December 31,		
	2013	2012	2011
Other expense (income)			
Natural Gas Pipelines(a)	$ (24)	$ 14	$ 1
CO_2—KMP	—	(7)	—
Products Pipelines—KMP	6	(5)	(8)
Terminals—KMP	(74)	(14)	1
Other	(7)	(1)	—
Total consolidated other expense (income)	$ (99)	$ (13)	$ (6)

	Year Ended December 31,		
	2013	2012	2011
DD&A			
Natural Gas Pipelines(a)	$ 797	$ 478	$ 163
CO_2—KMP	533	494	492
Products Pipelines—KMP	155	143	131
Terminals—KMP	247	236	226
Kinder Morgan Canada—KMP	54	56	56
Other	20	12	—
Total consolidated DD&A	$ 1,806	$ 1,419	$ 1,068

	Year Ended December 31,		
	2013	2012	2011
Earnings (loss) from equity investments			
Natural Gas Pipelines(a)(d)	$ 232	$ 52	$ 158
CO_2—KMP	24	25	24
Products Pipelines—KMP	45	39	34
Terminals—KMP	22	21	11
Kinder Morgan Canada—KMP	4	5	(2)
Other	—	11	1
Total consolidated equity earnings (loss)	$ 327	$ 153	$ 226

	Year Ended December 31,		
	2013	2012	2011
Amortization of excess cost of equity investments			
Natural Gas Pipelines(a)	$ 32	$ 17	$ 1
CO_2—KMP	2	2	2
Products Pipelines—KMP	5	4	4
Total consolidated amortization of excess cost of equity investments	$ 39	$ 23	$ 7

	Year Ended December 31,		
	2013	2012	2011
Interest income			
Natural Gas Pipelines	$ —	$ 18	$ —
CO_2—KMP	—	—	1
Products Pipelines—KMP	2	2	3
Kinder Morgan Canada—KMP	3	14	14
Other	8	3	—
Total segment interest income	13	37	18
Unallocated interest income	2	(9)	3
Total consolidated interest income	$ 15	$ 28	$ 21

	Year Ended December 31,		
	2013	2012	2011
Other, net-income (expense)			
Natural Gas Pipelines(e)	$ 578	$ 4	$ (164)
CO_2—KMP	—	(1)	4
Products Pipelines—KMP	1	9	5
Terminals—KMP	1	2	6
Kinder Morgan Canada—KMP(f)	246	3	—
Other	9	2	(1)
Total consolidated other, net-income (expense)	$ 835	$ 19	$ (150)

	Year Ended December 31,		
	2013	2012	2011
Income tax benefit (expense)			
Natural Gas Pipelines	$ (9)	$ (5)	$ (3)
CO_2—KMP	(7)	(5)	(4)
Products Pipelines—KMP	2	2	(3)
Terminals—KMP	(14)	(3)	5
Kinder Morgan Canada—KMP(g)	(105)	(1)	(15)
Total segment income tax expense	(133)	(12)	(20)
Unallocated income tax expense	(609)	(127)	(341)
Total consolidated income tax expense	$ (742)	$ (139)	$ (361)

	Year Ended December 31,		
	2013	2012	2011
Segment EBDA(h)			
Natural Gas Pipelines(a)	$ 4,207	$ 2,174	$ 563
CO_2—KMP	1,435	1,322	1,117
Products Pipelines—KMP	602	668	461
Terminals—KMP	836	708	702
Kinder Morgan Canada—KMP	340	229	202
Other	(5)	7	—
Total segment EBDA	7,415	5,108	3,045
Total segment DD&A	(1,806)	(1,419)	(1,068)
Total segment amortization of excess cost of equity investments	(39)	(23)	(7)
Other revenues	36	35	36
General and administrative expenses(i)	(613)	(929)	(515)
Interest expense, net of unallocable interest income(j)	(1,688)	(1,441)	(701)
Unallocable income tax expense	(609)	(127)	(341)
(Loss) income from discontinued operations, net of tax(k)	(4)	(777)	211
Total consolidated net income	$ 2,692	$ 427	$ 660

	Year Ended December 31,		
	2013	2012	2011
Capital expenditures			
Natural Gas Pipelines(a)	$ 1,085	$ 499	$ 153
CO_2—KMP	667	453	432
Products Pipelines—KMP	416	307	254
Terminals—KMP	1,108	707	332
Kinder Morgan Canada—KMP	77	16	28
Other	16	40	1
Total consolidated capital expenditures	$ 3,369	$ 2,022	$ 1,200

	2013	2012
Investments at December 31		
Natural Gas Pipelines	$ 5,130	$ 5,193
CO_2—KMP	12	11
Products Pipelines—KMP	611	400
Terminals—KMP	196	179
Kinder Morgan Canada—KMP	1	1
Other	1	20
Total consolidated investments	$ 5,951	$ 5,804

	2013	2012
Assets at December 31		
Natural Gas Pipelines(a)	$ 52,357	$ 46,600
CO_2—KMP	4,708	4,148
Products Pipelines—KMP	6,648	6,089
Terminals—KMP	6,888	5,931
Kinder Morgan Canada—KMP	1,677	1,724
Other	568	601
Total segment assets	72,846	65,093
Corporate assets(l)	2,339	2,854
Assets held for sale(m)	—	298
Total consolidated assets	$ 75,185	$ 68,245

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(a) The changes in the 2012 amount versus the 2011 amount include the effects of the acquisition of EP and for 2013 versus 2012 only, KMP's acquisition of Copano. See Note 3.
(b) Primarily represents a reimbursement of general and administrative costs for services we perform for NGPL Holdco LLC.
(c) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
(d) 2013 and 2012 amounts include impairment charges of $65 million and $200 million, respectively, to reduce the carrying value of our investment in NGPL Holdco LLC (see Note 6).
(e) 2013 amount includes a $558 million gain from the remeasurement of our previously held 50% equity interest in Eagle Ford to fair value (discussed further in Note 3). 2011 amount includes a $167 million loss from the remeasurement of KMP's previously held 50% equity interest in KinderHawk to fair value (see Note 3).
(f) 2013 amount includes a $224 million gain from the sale of our equity and debt investments in the Express pipeline system (discussed further in Note 3).
(g) 2013 amount includes an $84 million increase in expense related to the pre-tax gain amount described in footnote (f).
(h) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).
(i) 2012 amount includes $352 million of pretax expense associated with the EP acquisition and EP Energy sale.
(j) Includes (i) interest expense and (ii) miscellaneous other income and expenses not allocated to business segments. 2012 amount includes $108 million of expense for capitalized financing fees associated with the EP acquisition financing that were written-off (due to debt repayments) or amortized.
(k) Represents amounts from KMP's FTC Natural Gas Pipelines disposal group and other, net of tax (see Note 3).
(l) 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.
(m) Primarily represents amounts attributable to KMP's Express pipelines system and our ownership interest in Bolivia to Brazil Pipeline.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2013, 2012 and 2011, we reported total consolidated interest expense of $1,690 million, $1,427 million, and $703 million, respectively.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2013	2012	2011
Revenues from external customers			
U.S.	$ 13,656	$ 9,488	$ 7,513
Canada	398	407	411
Mexico and other(a)	16	78	19
Total consolidated revenues from external customers	$ 14,070	$ 9,973	$ 7,943

	2013	2012	2011
Long-lived assets at December 31(b)			
U.S.	$ 42,080	$ 37,651	$ 20,848
Canada	2,214	2,035	1,863
Mexico and other(a)	81	82	84
Total consolidated long-lived assets	$ 44,375	$ 39,768	$ 22,795

(a) Includes operations in Mexico and until August 31, 2011, the Netherlands.
(b) Long-lived assets exclude goodwill and other intangibles, net.

16. 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 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, 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

The tariffs and rates charged by SFPP and EPNG are subject to a number of ongoing proceedings at the FERC. A substantial portion of our legal reserves relate to these FERC cases and the CPUC cases described below them.

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. 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). If the shippers are successful in proving 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 KMP may include in its rates. With respect to all of the SFPP proceedings at the FERC, we estimate that the shippers are seeking approximately $20 million in annual rate reductions and approximately $100 million in refunds. However, applying the principles of several recent FERC decisions in SFPP cases, as applicable, to pending cases would result in substantially lower rate reductions and refunds than those sought by the shippers. We do not expect refunds in these cases to have an impact on KMP's distributions to its limited partners or our dividends to our shareholders.

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) in May 2012. EPNG implemented certain aspects of that decision and believes it has an appropriate reserve related to the findings in Opinion 517. EPNG has sought rehearing on Opinion 517. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528) on October 17, 2013. The FERC ordered EPNG to file within 60 days of issuance of Opinion 528 revised pro forma recalculated rates consistent with the terms of Opinion 528. The FERC has ordered additional proceedings concerning one of the issues in Opinion 528. EPNG has filed for rehearing on certain issues in Opinion 528. We have evaluated all recent decisions and believe our reserve is appropriate.

California Public Utilities Commission Proceedings

KMP has previously reported ratemaking and complaint proceedings against SFPP pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services. These matters have generally been consolidated and assigned to two administrative law judges.

On May 26, 2011, the CPUC issued a decision in several intrastate rate cases involving SFPP and a number of its shippers, (the "Long" cases). The decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance, allocation of environmental expenses, and refund liability, which KMP believes are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. On March 8, 2012, the CPUC issued another decision related to the Long cases. This decision largely reflected the determinations made on May 26, 2011, including the denial of an income tax allowance for SFPP. The CPUC's order denied SFPP's request for rehearing of the CPUC's income tax allowance treatment, while granting requested rehearing of various, other issues relating to SFPP's refund liability and staying the payment of refunds until resolution of the outstanding issues on rehearing. On March 23, 2012, SFPP filed a petition for writ of review in the California Court of Appeals, seeking a court order vacating the CPUC's determination that SFPP is not entitled to recover an income tax allowance in its intrastate rates. The Court denied SFPP's petition, and on October 16, 2013, the California Supreme Court declined SFPP's request for further review. SFPP is currently assessing the precise impact of the now final state rulings denying SFPP an income tax allowance and is awaiting CPUC decisions that will determine the impact related to the denial of an income tax allowance.

On April 6, 2011, in proceedings unrelated to the above-referenced CPUC dockets, a CPUC administrative law judge issued a proposed decision (Bemesderfer case) substantially reducing SFPP's authorized cost of service and ordering SFPP to pay refunds from May 24, 2007 to the present of revenues collected in excess of the authorized cost of service. The proposed decision was subsequently withdrawn, and the presiding administrative law judge is expected to reissue a proposed decision at some indeterminate time in the future.

On January 30, 2012, SFPP filed an application reducing its intrastate rates by approximately 7%. This matter remains pending before the CPUC, with a decision expected in the second quarter of 2014.

On July 19, 2013, Calnev filed an application with the CPUC requesting a 36% increase in its intrastate rates. A decision from the CPUC approving the request rate increase was issued on November 14, 2013.

On November 27, 2013, the CPUC issued its Order to Show Cause directing SFPP to demonstrate whether or not the CPUC should require immediate refund payments associated with various pending SFPP rate matters. Subsequently, the CPUC issued an order directing SFPP and its shippers to engage in mandatory settlement discussions. If the matter is not settled, a decision addressing, if not resolving, all pending SFPP rate matters at the CPUC is anticipated in the second quarter of 2014.

Based on KMP's review of these CPUC proceedings and the shipper comments thereon, it estimates that the shippers are requesting approximately $400 million in reparation payments and approximately $30 million in annual rate reductions. The actual amount of reparations will be determined through further proceedings at the CPUC. As of December 31, 2013, we believe our legal reserve, including an adjustment of the reserve made in the second quarter of 2013 related in part to this matter, is adequate such that the resolution of pending CPUC matters will not have a material adverse impact on KMP's business, financial position or results of operations. Furthermore, we do not expect any reparations that KMP would pay in this matter to impact the per unit cash distributions it expects to pay to its limited partners for 2014.

Copano Shareholders' Litigation

Three putative class action lawsuits were filed in connection with KMP's merger with Copano: (i) Schultes v. Copano Energy, L.L.C., et al. (Case No. 06966), in the District Court of Harris County, Texas, which is referred to as the Texas State Action; (ii) Bruen v. Copano Energy, L.L.C., et al. (Case No. 4:13-CV-00540) in the U.S. District Court for the Southern District of Texas, which is referred to as the Texas Federal Action; and (iii) In re Copano Energy, L.L.C. Shareholder Litigation, Case No. 8284-VCN in the Court of Chancery of the State of Delaware, which is referred to as the Delaware Action, which reflects the consolidation of three actions originally filed in the Court of Chancery. The Texas State Action, the Texas Federal Action and the Delaware Action are collectively referred to as the "Actions."

The Actions name Copano, R. Bruce Northcutt, William L. Thacker, James G. Crump, Ernie L. Danner, T. William Porter, Scott A. Griffiths, Michael L. Johnson, Michael G. MacDougall, Kinder Morgan G.P., Inc., KMEP and Javelina Merger Sub

LLC as defendants. The Actions were purportedly brought on behalf of a putative class seeking to enjoin the merger and allege, among other things, that the members of Copano's board of directors breached their fiduciary duties by agreeing to sell Copano for inadequate and unfair consideration and pursuant to an inadequate and unfair process, and that Copano, KMEP, Kinder Morgan G.P., Inc. and Javelina Merger Sub LLC aided and abetted such alleged breaches. In addition, the plaintiffs in each of the Texas State Action and the Delaware Action alleged that the Copano directors breached their duty of candor to unitholders by failing to provide the unitholders with all material information regarding the merger and/or made misstatements in the preliminary proxy statement. The plaintiffs in the Texas Federal Action also asserted a claim under the federal securities laws alleging that the preliminary proxy statement omits and/or misrepresents material information in connection with the merger.

On April 21, 2013, the parties in all the Actions executed a Memorandum of Understanding pursuant to which Copano agreed to make certain additional disclosures concerning the merger in a Form 8-K, which Copano filed on April 22, 2013, and the plaintiffs agreed to enter into a stipulation of settlement providing for full settlement and dismissal with prejudice of each of the Actions. The parties then prepared and filed a Stipulation of Settlement with the Delaware Chancery Court, and on June 28, 2013, Copano announced that we had reached an agreement with the plaintiffs to settle all claims asserted against all defendants. The settlement does not require the defendants to pay any monetary consideration to the proposed settlement class. Following notice to the putative class, the Delaware Chancery Court held a settlement hearing and issued a final order approving the settlement on September 9, 2013. The order, among other things, dismissed the Delaware Action with prejudice and provided for a release in favor of all of the defendants for any and all claims by any of the putative class members arising out of the merger. The order also awarded plaintiffs' counsel in the Delaware action $450,000 for their fees and expenses, to be paid by defendants. The plaintiff in the Texas Federal Action dismissed his case on May 13, 2013 and intervened in the Texas State Action on August 12, 2013 for the sole purpose of advancing a joint motion and petition for attorneys' fees and expenses. On October 11, 2013, the court in the Texas State Action entered an order and final judgment denying plaintiffs' joint motion for fees and expenses.

Other Commercial Matters

Union Pacific Railroad Company Easements

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 judge determined that the annual rent payable as of January 1, 2004 was, $15 million subject to annual consumer price index increases. SFPP has appealed the judge's determination, but if that determination is upheld, SFPP would owe approximately $90 million in back rent. Accordingly, KMP increased its rights-of-way liability to cover this potential liability for back rent. In addition, the judge determined that UPRR is entitled to an estimated $20 million for interest on the outstanding back rent liability. KMP believes the award of interest is without merit and are pursuing our appellate rights. By notice dated October 25, 2013, UPRR demanded the payment of $22.25 million in rent for the first year of the next ten-year period beginning January 1, 2014. SFPP rejected the demand and the parties are pursuing the dispute resolution procedure in their contract to determine the rental adjustment, if any, for such period.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP appealed this decision, and in December 2008, the appellate court affirmed the decision. 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 is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. A trial occurred in the fourth quarter of 2011, with a verdict having been reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. A judgment has not been entered on the verdict and SFPP is continuing to evaluate its post-trial and appellate options.

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 expense (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position, our results of operations, our cash flows, and our distributions to our limited partners. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal and located in Sparrows Point, Maryland collapsed while being operated by our subsidiary Kinder Morgan Bulk Terminals, Inc. (KMBT). According to KMP's investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the U.S. District Court for the District of Maryland, Case No. 09CV1668-WMN. Severstal and its successor in interest, RG Steel, allege that KMBT was contractually obligated to replace the collapsed crane and that its employees were negligent in failing to properly secure the crane prior to the collapse. RG Steel seeks to recover in excess of $30 million for the alleged value of the crane and lost profits. KMBT denies each of RG Steel's allegations. A bench trial occurred in November 2013 and we are awaiting the court's decision.

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 has agreed to indemnify TGP in connection with the gas commitment and reporting claims. We intend to vigorously defend the suit.

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

In December 2011 (*Brinckerhoff I*), March 2012, (*Brinckerhoff II*) and May 2013 (Brinckerhoff III) derivative lawsuits were filed in Delaware Chancery Court against EP, El Paso Pipeline GP Company, L.L.C., the general partner of EPB, and the directors of the general partner. EPB was named in these lawsuits as a "Nominal Defendant." The lawsuits arise from the March 2010, November 2010 and May 2012 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. Defendants' motion to dismiss in Brinckerhoff I was denied in part. Brinckerhoff I and II have been consolidated into one proceeding. The parties' motions for summary judgment filed by Plaintiff and Defendants are pending. A motion to dismiss has been filed in Brinckerhoff III. Defendants continue to believe that these actions are without merit and intend to defend against them vigorously.

Allen v. El Paso Pipeline GP Company, L.L.C., et al.

In May 2012, a unitholder of EPB filed a purported class action in Delaware Chancery Court, alleging both derivative and non derivative claims, against EPB, and EPB's general partner and its board. EPB was named in the lawsuit as both a "Class Defendant" and a "Derivative Nominal Defendant." The complaint alleges a breach of the duty of good faith and fair dealing in connection with the March 2011 sale to EPB of a 25% ownership interest in SNG. Defendants' motion to dismiss was denied, and Defendants' motion for summary judgment is pending. Defendants continue to believe this action is without merit, and intend to defend against it vigorously.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that EP, EPM and other energy companies 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. A petition for certiorari is pending before the U.S. Supreme Court. 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.

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, 2013 and 2012, our total reserve for legal matters was $624 million and $425 million, respectively. The reserve primarily relates to various claims from regulatory proceedings arising from KMP's products pipeline and natural gas pipeline transportation rates. The overall change in the reserve from December 31, 2012 was primarily due to increases in expense in 2013 associated with adjustments to interstate and California intrastate transportation rate case liabilities.

Other

Slotoroff v. Kinder Morgan, Inc., Kinder Morgan G.P., Inc., et al.

On February 5, 2014, a putative class action and derivative complaint was filed in the Court of Chancery in the State of Delaware (Case No. 9318) against defendants Kinder Morgan, Inc., Kinder Morgan G.P., Inc. and nominal defendant Kinder Morgan Energy Partners, L.P. The suit was filed by a purported unitholder of KMP and seeks to assert claims both individually and on behalf of a putative class consisting of all public holders of KMP units during the period of February 5, 2011 through the date of the filing of the suit. The suit alleges 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 alleges 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 KMP's distributions and growth rate. The suit seeks 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 KMP's maintenance capital expenses, together with other unspecified monetary damages including punitive damages and attorney fees. Defendants believe that this suit is without merit and intend to defend it vigorously.

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.

Colorado Oil and Gas Conservation Commission Inspections

In Fall 2012, the Colorado Oil and Gas Conservation Commission, referred to as COGCC, performed inspections at multiple well sites in Southwestern Colorado owned by $KMCO_2$ and some of these inspections resulted in alleged violations of COGCC's rules. $KMCO_2$ took immediate steps to correct the alleged deficiencies and has engaged COGCC and other agencies in its efforts to maintain compliance. In June 2013, the parties settled the matter through an Administrative Order on Consent under which $KMCO_2$ agreed to pay $220,000 of which up to $80,000 may be paid toward a public project. The agreed public project, has been completed and this matter is concluded.

New Jersey Department of Environmental Protection v. Occidental Chemical Corporation, et al. (Defendants), Maxus Energy Corp. and Tierra Solutions, Inc. (Third Party Plaintiffs) v. 3M Company et al., Superior Court of New Jersey, Law Division - Essex County, Docket No. L-9868-05

The New Jersey Department of Environmental Protection (NJDEP) sued Occidental Chemical and others under the New Jersey Spill Act for contamination in the Newark Bay Complex including numerous waterways and rivers. In 2009, Occidental et al. asserted claims for contribution against approximately 300 third party defendants. NJDEP claimed damages related to 40 years of discharges of TCDD (a form of dioxin), DDT and "other hazardous substances." GATX Terminals Corporation (n/k/a Kinder Morgan Liquids Terminals LLC) (KMLT) was named as a third party defendant because of the noted hazardous substances language and because the Carteret, New Jersey facility (a former GATX Terminals facility) is located on the Arthur Kill River, one of the waterways included in the litigation. KMLT, as part of a joint defense group, entered a settlement agreement (Consent Judgment) with the NJDEP whereby the settling parties for a prescribed payment, obtained a contribution bar against first party defendants Occidental, Maxus and Tierra in addition to a release of claims. The Consent Judgment was published in the New Jersey Register for a 60-day comment period and no significant comments were received. Additionally, the NJDEP reached a settlement agreement with Maxus and Tierra. Occidental is not part of the settlement. On December 12, 2013, the court approved the settlements between NJDEP and the third-party defendants and between NJDEP and the Maxus Tierra parties. Pursuant to the Consent Judgment, KMLT submitted its settlement payment by the January 27, 2014 deadline and is awaiting a court order formally dismissing KMLT from the litigation.

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 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. Currently, KMLT and 90 other parties are involved in an allocation process to determine each party's respective share of the cleanup costs. This is a non-judicial allocation process. KMP is participating in the allocation process on behalf of both KMLT and KMBT. Each entity has two facilities located in Portland Harbor. KMP expects the allocation to conclude in 2014 and the EPA to issue its Record of Decision in 2015. It is anticipated that the cleanup activities will begin within one year of the issuance of the Record of Decision.

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

This is a CERCLA case brought by a water purveyor whose wells have allegedly been contaminated due to the presence of a number of contaminants. The First Amended Complaint sought $175 million in damages against approximately 70 defendants. On August 6, 2013 plaintiffs filed its Second Amended Complaint (SAC) seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims now presented in the SAC 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. On October 24, 2013, we moved to dismiss the SAC.

The City of Los Angeles v. Kinder Morgan Liquids Terminals, LLC, Shell Oil Company, Equilon Enterprises LLC; California Superior Court, County of Los Angeles, Case No. NC041463

KMLT was a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. On April 9, 2013, KMLT and the Port of Los Angeles entered into a

Settlement and Release Agreement the terms of which provide for the dismissal of the litigation by the Port and KMLT's agreement to pay 60% of the Port's costs to remediate the former terminal site up to a $15 million cap. Further, according to terms of the Settlement and Release, KMP received a 5-year lease extension that allows KMLT to continue fuel loading and offloading operations at another KMLT Port of Los Angeles terminal property. The Court approved the parties' Good Faith Settlement motion in the Superior Court and dismissed the case.

The City of Los Angeles, KMLT, Chevron and Phillips 66 remain named on a Cleanup and Abatement Order from the California Regional Water Quality Control Board as parties responsible for the cleanup of the former Los Angeles Marine Terminal. The private parties have all settled with the City of Los Angeles and agreed to pay a percentage of the City's costs to perform the required cleanup at the site.We anticipate that cleanup activities by the Port will begin within the first quarter of 2014.

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, LLC and ST Services, Inc.

On April 23, 2003, ExxonMobil filed a complaint in the Superior Court of New Jersey, Gloucester County. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corporation from 1989 through September 2000, and later owned by Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, which is also a party to the lawsuit.

On June 25, 2007, the NJDEP, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil and KMLT, formerly known as GATX Terminals Corporation, alleging natural resource damages related to historic contamination at the Paulsboro terminal. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals/Plains. The court consolidated the two cases.

In mid 2011, KMLT and Plains Products entered into a settlement agreement and subsequent Consent Judgment with the NJDEP which resolved the state's alleged natural resource damages claim. The natural resource damage settlement includes a monetary award of $1 million and a series of remediation and restoration activities at the terminal site. KMLT and Plains Products have joint responsibility for this settlement. Simultaneously, KMLT and Plains Products entered into an agreement that settled each party's relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now entered with the Court and the settlement is final. According to the agreement, Plains will conduct remediation activities at the site and KMLT will provide oversight and 50% of the costs. We anticipate remediation activities to begin by second quarter 2014.

The settlement with the state did not resolve the original complaint brought by ExxonMobil. On or around, April 10, 2013, KMLT, Plains and ExxonMobil settled the original Exxon complaint for past remediation costs for $750,000 to be split 50/50 between KMLT and Plains. All parties have now executed the agreement and the litigation is settled and dismissed.

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 KMP 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, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, KMP removed the case to the U.S. District Court, Southern District of California, case number 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 their 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 issued its final order reaffirming in all respects its tentative rulings and 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 of this case to the U.S. Court of Appeals for the Ninth Circuit. The appeal is currently pending.

This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. SFPP continues to conduct an extensive remediation effort at the City's stadium property site.

On May 7, 2013, the City of San Diego filed a writ of mandamus to the California Superior Court seeking an order from the Court setting aside the California Regional Water Quality Control Board's (RWQCB) approval of KMP's permit request to increase the discharge of water from KMP's groundwater treatment system to the City of San Diego's municipal storm sewer system. KMEP is coordinating with the RWQCB to oppose the City's writ.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., an historical subsidiary of EPNG, operated 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. We are also seeking contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given their pervasive control over all aspects of the nuclear weapons program.

PHMSA Inspection of Carteret Terminal, Carteret, NJ

On April 4, 2013, the PHMSA, Office of Pipeline Safety issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order (NOPV) arising from an inspection at the KMLT, Carteret, New Jersey location on March 15, 2011 following a release and fire that occurred during maintenance activity on March 14, 2011. On July 17, 2013, KMLT entered into a Consent Agreement and Order with the PHMSA, pursuant to which KMLT paid a penalty of $63,100 and is required to complete ongoing pipeline integrity testing and other corrective measures by May, 2015.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (Flood Protection Authority) 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 one hundred 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 Flood Protection Authority 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 September 10, 2013, the Flood Protection Authority filed a motion to remand the case to the state district court for Orleans Parish. On December 18, 2013, a hearing was conducted on the remand motion and it remains under consideration by the court.

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. On December 18, 2013, defendants removed the case to the U.S. District Court for the Eastern District of Louisiana. On January 14, 2014, the plaintiff filed a motion to remand the case to state court and such motion remains pending.

Pennsylvania Department of Environmental Protection Notice of Alleged Violations

The Pennsylvania Department of Environmental Protection (PADEP) has notified TGP of alleged violations of certain conditions to the construction permits issued to TGP for the construction of TGP's 300 Line Project in 2011. The alleged violations arise from field inspections performed during construction by county conservation districts, as delegates of the PADEP, and generally involve the alleged failure by TGP to implement and maintain best practices to achieve sufficient erosion and sediment controls, stabilization of the right of way, and prevention of potential discharge of sediment into the waters of the commonwealth during construction and before placing the line into service. To resolve such alleged violations, the PADEP initially proposed a collective penalty of approximately $1.5 million. TGP and the PADEP are seeking to reach a mutually agreeable resolution of the alleged notices of violations, including an agreed penalty amount.

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, 2013 and 2012, we have accrued a total reserve for environmental liabilities in the amount of $378 million and $421 million, respectively, of which $208 million and $253 million, respectively, are associated with KMI (excluding KMP and EPB) and primarily relate to legacy sites acquired in the May 25, 2012 EP acquisition. In addition, as of December 31, 2013 and December 31, 2012, we have recorded a receivable of $14 million and $22 million, respectively, for expected cost recoveries that have been deemed probable.

17. Recent Accounting Pronouncements

Accounting Standards Updates

On March 5, 2013, the FASB issued ASU No. 2013-05, "Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity (a consensus of the FASB Emerging Issues Task Force)." This ASU amends the FASB's Accounting Standards Codification (ASC) 830, "Foreign Currency Matters," and ASC 810, "Consolidation," to address diversity in practice related to the release of cumulative translation adjustments (CTA) into earnings upon the occurrence of certain derecognition events. ASU No. 2013-05 precludes the release of CTA for derecognition events that occur within a foreign entity, unless such events represent a complete or substantially complete liquidation of the foreign entity; however, derecognition events related to investments in a foreign entity result in the release of all CTA related to the derecognized foreign entity, even when a noncontrolling financial interest is retained. ASU No. 2013-05 also amends ASC 805, "Business Combinations," for transactions that result in a company obtaining control of a business in a step acquisition by increasing an investment in a foreign entity from one accounted for under the equity method to one accounted for as a consolidated investment. For us, ASU No. 2013-05 was effective January 1, 2014, and the adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

18. Reconciliation of Significant Asset and Liability Balances

The following is a reconciliation between KMP's and EPB's significant asset balances as reported in KMP's and EPB's Annual Report on Form 10-K as of December 31, 2013 and 2012 and our consolidated asset balances as shown on our accompanying consolidated balance sheets (in millions):

	December 31,	
	2013	2012
Cash and cash equivalents - KMI(a)	$ 116	$ 71
Cash and cash equivalents - KMP	404	529
Cash and cash equivalents - EPB	78	114
Cash and cash equivalents	$ 598	$ 714
Property, plant and equipment, net–KMI(a)	$ 2,563	$ 2,735
Property, plant and equipment, net–KMP	27,405	22,330
Property, plant and equipment, net–EPB	5,879	5,931
Property, plant and equipment, net	$ 35,847	$ 30,996
Goodwill–KMI(a)	$ 17,935	$ 18,193
Goodwill–KMP	6,547	5,417
Goodwill–EPB	22	22
Goodwill	$ 24,504	$ 23,632
Current portion of debt–KMI(a)	$ 725	$ 1,153
Current portion of debt–KMP	1,504	1,155
Current portion of debt–EPB	77	93
Current portion of debt	$ 2,306	$ 2,401
Long-term debt outstanding–KMI(a)	$ 9,221	$ 9,148
Long-term debt outstanding–KMP	18,410	15,907
Long-term debt outstanding–EPB(b)	4,179	4,254
Long-term debt outstanding	$ 31,810	$ 29,309

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(a) Includes assets and liabilities of KMI's consolidated subsidiaries, excluding KMP and EPB.

(b) Excludes debt fair value adjustments. Decrease to long-term debt for debt fair value adjustments totaled $8 million as of both December 31, 2013 and 2012.

19. Guarantee of Securities of Subsidiaries

KMI had guaranteed the payment of the outstanding senior notes issued by El Paso LLC (formerly known as El Paso Corporation) as a result of the EP acquisition. These notes were also guaranteed by El Paso Holdco LLC ("El Paso Holdco"), El Paso LLC's direct parent. El Paso Issuing Corporation ("Finance Corp"), a direct subsidiary of El Paso LLC, is the co-issuer of these notes. The aggregate principal amount of these series of El Paso LLC senior notes are referred to as the "Guaranteed Notes". On October 3, 2013, El Paso LLC transferred substantially all of its assets to El Paso Holdco pursuant to an internal restructuring transaction. In connection with such internal restructuring, El Paso Holdco succeeded El Paso LLC as issuer with respect to the Guaranteed Notes, and El Paso LLC ceased to be an obligor with respect to the Guaranteed Notes. Prior to the internal restructuring, El Paso Holdco had been presented as the "Guarantor Subsidiary" and is now presented as one of the "Subsidiary Issuers." KMI continues to guarantee the payment of the Guaranteed Notes. Finance Corp's obligations as a co-issuer and primary obligor continue to be joint and several with the obligations of El Paso Holdco as issuer. As of both December 31, 2013, and 2012, approximately $3.8 billion and $3.9 billion, respectively, of these guaranteed notes are outstanding. Subject to the limitations set forth in the applicable supplemental indentures, the guarantee of KMI is full and unconditional and joint and several, and guarantee the Guaranteed Notes through their respective maturity dates, the latest of which is in 2037. Finance Corp has no subsidiaries and no independent assets or operations. A significant amount of KMI's income and cash flow are generated by its subsidiaries. As a result, the funds necessary to meet KMI's debt service and/or guarantee obligations are provided in large part by distributions or advances from its subsidiaries. Included among the non-guarantor subsidiaries are KMP, KMR and EPB, along with KMGP, the general partner of KMP and El Paso Pipeline GP Company, L.L.C., the general partner of EPB. In the following condensed consolidating financial information, KMI is "Parent Guarantor," and El Paso Holdco and Finance Corp are the "Subsidiary Issuers." Both of the Subsidiary Issuers are 100% owned by KMI.

The condensed consolidating financial information for all periods presented below reflect the internal restructuring transaction described above.

Condensed Consolidating Balance Sheets as of December 31, 2013
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
ASSETS					
Cash and cash equivalents	$ 83	$ —	$ 515	$ —	$ 598
All other current assets	945	38	2,763	(476)	3,270
Property, plant and equipment, net	10	—	35,837	—	35,847
Investments	—	—	5,951	—	5,951
Investments in subsidiaries	20,336	6,651	—	(26,987)	—
Goodwill	—	8,062	16,442	—	24,504
Notes receivable from affiliates	—	—	1,993	(1,993)	—
Deferred charges and all other assets	227	841	4,759	(812)	5,015
Total assets	$ 21,601	$ 15,592	$ 68,260	$ (30,268)	$ 75,185
LIABILITIES AND STOCKHOLDERS' EQUITY					
Liabilities					
Current portion of debt	$ 175	$ 400	$ 1,731	$ —	$ 2,306
All other current liabilities	228	135	3,882	(476)	3,769
Long-term debt	3,371	3,999	26,517	—	33,887
Notes payable to affiliates	1,993	—	—	(1,993)	—
Deferred income taxes	2,426	—	3,037	(812)	4,651
All other long-term liabilities	315	69	1,903	—	2,287
Total liabilities	8,508	4,603	37,070	(3,281)	46,900
Stockholders' equity					
Total KMI equity	13,093	10,989	15,596	(26,585)	13,093
Noncontrolling interests	—	—	15,594	(402)	15,192
Total stockholders' equity	13,093	10,989	31,190	(26,987)	28,285
Total liabilities and stockholders' equity	$ 21,601	$ 15,592	$ 68,260	$ (30,268)	$ 75,185

Condensed Consolidating Balance Sheets as of December 31, 2012
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
ASSETS					
Cash and cash equivalents	$ 3	$ 45	$ 666	$ —	$ 714
All other current assets	813	51	9,322	(7,226)	2,960
Property, plant and equipment, net	8	—	30,988	—	30,996
Investments	—	19	5,785	—	5,804
Investments in subsidiaries	20,053	13,501	—	(33,554)	—
Goodwill	—	8,059	15,573	—	23,632
Notes receivable from affiliates	1,555	—	2,095	(3,650)	—
Deferred charges and all other assets	202	879	3,914	(856)	4,139
Total assets	$ 22,634	$ 22,554	$ 68,343	$ (45,286)	$ 68,245
LIABILITIES AND STOCKHOLDERS' EQUITY					
Liabilities					
Current portion of debt	$ 1,035	$ 115	$ 1,251	$ —	$ 2,401
All other current liabilities	196	7,024	2,833	(7,226)	2,827
Long-term debt	3,068	4,378	24,554	—	32,000
Notes payable to affiliates	1,764	331	1,555	(3,650)	—
Deferred income taxes	2,095	—	2,832	(856)	4,071
All other long-term liabilities	610	169	2,067	—	2,846
Total liabilities	8,768	12,017	35,092	(11,732)	44,145
Stockholders' equity					
Total KMI equity	13,866	10,537	22,858	(33,395)	13,866
Noncontrolling interests	—	—	10,393	(159)	10,234
Total stockholders' equity	13,866	10,537	33,251	(33,554)	24,100
Total liabilities and stockholders' equity	$ 22,634	$ 22,554	$ 68,343	$ (45,286)	$ 68,245

Condensed Consolidating Statements of Income for the Year Ended December 31, 2013
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Revenues	$ 36	$ —	$ 14,066	$ (32)	$ 14,070
Costs, expenses and other					
Costs of sales	—	—	5,253	—	5,253
Depreciation, depletion and amortization	1	—	1,805	—	1,806
Other operating expenses	20	(3)	3,036	(32)	3,021
Total costs, expenses and other	21	(3)	10,094	(32)	10,080
Operating income	15	3	3,972	—	3,990
Other income (expense)					
Earnings from equity investments	1,386	553	327	(1,939)	327
Interest, net	(262)	(305)	(1,108)	—	(1,675)
Amortization of excess cost of equity investments and other, net	—	—	796	—	796
Income from continuing operations before income taxes	1,139	251	3,987	(1,939)	3,438
Income tax benefit (expense)	54	89	(885)	—	(742)
Income from continuing operations	1,193	340	3,102	(1,939)	2,696
Loss from discontinued operations, net of tax	—	—	(4)	—	(4)
Net income	1,193	340	3,098	(1,939)	2,692
Net income attributable to noncontrolling interests	—	—	(1,595)	96	(1,499)
Net income attributable to controlling interests	$ 1,193	$ 340	$ 1,503	$ (1,843)	$ 1,193

Condensed Consolidating Statements of Income for the Year Ended December 31, 2012
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Revenues	$ 35	$ —	$ 9,938	$ —	$ 9,973
Costs, expenses and other					
Costs of sales	—	—	3,057	—	3,057
Depreciation, depletion and amortization	—	—	1,419	—	1,419
Other operating expenses	232	62	2,610	—	2,904
Total costs, expenses and other	232	62	7,086	—	7,380
Operating (loss) income	(197)	(62)	2,852	—	2,593
Other income (expense)					
Earnings from equity investments	123	276	153	(399)	153
Interest, net	(381)	(265)	(753)	—	(1,399)
Amortization of excess cost of equity investments and other, net	(1)	—	(3)	—	(4)
(Loss) income from continuing operations before income taxes	(456)	(51)	2,249	(399)	1,343
Income tax benefit (expense)	771	(380)	(530)	—	(139)
					—
Income (loss) from continuing operations	315	(431)	1,719	(399)	1,204
Loss from discontinued operations, net of tax	—	—	(777)	—	(777)
Net income (loss)	315	(431)	942	(399)	427
Net income attributable to noncontrolling interests	—	—	(109)	(3)	(112)
Net income (loss) attributable to controlling interests	$ 315	$ (431)	$ 833	$ (402)	$ 315

Condensed Consolidating Statements of Income for the Year Ended December 31, 2011
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Revenues	$ 36	$ —	$ 7,907	$ —	$ 7,943
Costs, expenses and other					
Costs of sales	—	—	3,278	—	3,278
Depreciation, depletion and amortization	—	—	1,068	—	1,068
Other operating expenses	42	—	2,132	—	2,174
Total costs, expenses and other	42	—	6,478	—	6,520
Operating (loss) income	(6)	—	1,429	—	1,423
Other income (expense)					
Earnings from equity investments	712	—	226	(712)	226
Interest, net	(187)	—	(495)	—	(682)
Amortization of excess cost of equity investments and other, net	(1)	—	(156)	—	(157)
Income from continuing operations before income taxes	518	—	1,004	(712)	810
Income tax benefit (expense)	68	—	(429)	—	(361)
Income from continuing operations	586	—	575	(712)	449
Income from discontinued operations, net of tax	8	—	203	—	211
Net income	594	—	778	(712)	660
Net income attributable to noncontrolling interests	—	—	(71)	5	(66)
Net income attributable to controlling interests	$ 594	$ —	$ 707	$ (707)	$ 594

Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2013
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net Income	$ 1,193	$ 340	$ 3,098	$ (1,939)	$ 2,692
Other comprehensive income (loss), net of tax					
Change in fair value of derivatives utilized for hedging purposes	(14)	7	(38)	7	(38)
Reclassification of change in fair value of derivatives to net income	4	(2)	11	(2)	11
Foreign currency translation adjustments	(49)	—	(102)	48	(103)
Adjustments to pension and other postretirement benefit plan liabilities	153	16	50	(49)	170
Total other comprehensive income (loss)	94	21	(79)	4	40
Comprehensive income	1,287	361	3,019	(1,935)	2,732
Comprehensive income attributable to noncontrolling interests	—	—	(1,445)	—	(1,445)
Comprehensive income attributable to controlling interests	$ 1,287	$ 361	$ 1,574	$ (1,935)	$ 1,287

Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2012
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net Income (loss)	$ 315	$ (431)	$ 942	$ (399)	$ 427
Other comprehensive income (loss), net of tax					
Change in fair value of derivatives utilized for hedging purposes	32	(5)	86	(31)	82
Reclassification of change in fair value of derivatives to net income	(5)	(2)	(8)	7	(8)
Foreign currency translation adjustments	14	—	33	(15)	32
Adjustments to pension and other postretirement benefit plan liabilities	(44)	(14)	(4)	27	(35)
Total other comprehensive (loss) income	(3)	(21)	107	(12)	71
Comprehensive income (loss)	312	(452)	1,049	(411)	498
Comprehensive income attributable to noncontrolling interests	—	—	(186)	—	(186)
Comprehensive income (loss) attributable to controlling interests	$ 312	$ (452)	$ 863	$ (411)	$ 312

Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2011
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net income	$ 594	$ —	$ 778	$ (712)	$ 660
Other comprehensive income (loss), net of tax					
Change in fair value of derivatives utilized for hedging purposes	6	—	11	(4)	13
Reclassification of change in fair value of derivatives to net income	67	—	176	(59)	184
Foreign currency translation adjustments	(14)	—	(31)	10	(35)
Adjustments to pension and other postretirement benefit plan liabilities	(38)	—	(23)	7	(54)
Total other comprehensive income	21	—	133	(46)	108
Comprehensive income	615	—	911	(758)	768
Comprehensive income attributable to noncontrolling interests	—	—	(153)	—	(153)
Comprehensive income attributable to controlling interests	$ 615	$ —	$ 758	$ (758)	$ 615

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2013
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net cash provided by operating activities	$ 1,693	$ 91	$ 4,506	$ (2,226)	$ 4,064
Cash flows from investing activities					
Capital expenditures	(6)	—	(3,363)	—	(3,369)
Proceeds from sale of investments	—	—	490	—	490
Acquisitions of assets and investments	—	—	(292)	—	(292)
Repayments from related party	—	—	11	—	11
Funding to affiliates	(376)	(597)	(623)	1,596	—
Drop down assets to KMP	994	—	(994)	—	—
Contribution to investments	(6)	—	(217)	6	(217)
Investments in KMP and EPB	(65)	(3)	—	68	—
Distributions from equity investments in excess of cumulative earnings	18	23	183	(39)	185
Other, net	—	—	128	—	128
Net cash provided by (used in) investing activities	559	(577)	(4,677)	1,631	(3,064)
Cash flows from financing activities					
Issuance of debt	2,895	133	10,553	—	13,581
Payment of debt	(3,444)	(180)	(8,769)	—	(12,393)
Funding from affiliates	651	488	457	(1,596)	—
Debt issuance costs	(15)	—	(23)	—	(38)
Cash dividends	(1,622)	—	—	—	(1,622)
Repurchases of shares and warrants	(637)	—	—	—	(637)
Distributions to parent	—	—	(2,253)	2,253	—
Contributions from noncontrolling interests	—	—	1,762	(56)	1,706
Distributions to noncontrolling interests	—	—	(1,692)	—	(1,692)
Other, net	—	—	6	(6)	—
Net cash (used in) provided by financing activities	(2,172)	441	41	595	(1,095)
Effect of exchange rate changes on cash and cash equivalents	—	—	(21)	—	(21)
Net increase (decrease) in cash and cash equivalents	80	(45)	(151)	—	(116)
Cash and cash equivalents, beginning of period	3	45	666	—	714
Cash and cash equivalents, end of period	$ 83	$ —	$ 515	$ —	$ 598

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2012
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net cash provided by (used in) operating activities	$ 1,014	$ (369)	$ 3,757	$ (1,607)	$ 2,795
Cash flows from investing activities					
Capital expenditures	(5)	—	(2,017)	—	(2,022)
Proceeds from disposal of discontinued operations	—	—	1,791	—	1,791
Acquisitions of assets and investments	—	—	(83)	—	(83)
Repayments from related party	—	—	76	—	76
Funding to affiliates	(701)	(968)	(1,280)	2,949	—
Acquisition of EP	(5,212)	—	242	—	(4,970)
Drop down assets to KMP	3,485	—	(3,485)	—	—
Contributions to investments	(15)	—	(177)	—	(192)
Investments in KMP and EPB	(85)	(9)	—	94	—
Distributions from equity investments in excess of cumulative earnings	16	—	188	(4)	200
Other, net	—	1	115	—	116
Net cash used in investing activities	(2,517)	(976)	(4,630)	3,039	(5,084)
Cash flows from financing activities					
Issuance of debt	7,889	112	10,147	—	18,148
Payment of debt	(5,418)	(274)	(9,063)	—	(14,755)
Funding from affiliates	539	1,552	858	(2,949)	—
Debt issuance costs	(91)	—	(20)	—	(111)
Cash dividends	(1,184)	—	—	—	(1,184)
Repurchases of warrants	(157)	—	—	—	(157)
Distributions to parents	—	—	(1,597)	1,597	—
Contributions from noncontrolling interests	—	—	2,012	(73)	1,939
Distributions to noncontrolling interests	—	—	(1,219)	—	(1,219)
Other, net	(74)	—	4	(7)	(77)
Net cash provided by financing activities	1,504	1,390	1,122	(1,432)	2,584
Effect of exchange rate changes on cash and cash equivalents	—	—	8	—	8
Net increase in cash and cash equivalents	1	45	257	—	303
Cash and cash equivalents, beginning of period	2	—	409	—	411
Cash and cash equivalents, end of period	$ 3	$ 45	$ 666	$ —	$ 714

Condensed Consolidating Statements of Cash Flows for the Year Ended December 31, 2011
(In Millions)

	Parent Guarantor	Subsidiary Issuers	Non-guarantor Subsidiaries	Eliminations	Consolidated KMI
Net cash provided by operating activities	$ 957	$ —	$ 2,766	$ (1,357)	$ 2,366
Cash flows from investing activities					
Capital expenditures	(1)	—	(1,199)	—	(1,200)
Acquisitions of assets and investments	—	—	(1,179)	—	(1,179)
Repayments from related party	—	—	31	—	31
Funding to affiliates	(852)	—	(1)	853	—
Contributions to investments	(92)	—	(371)	92	(371)
Distributions from equity investments in excess of cumulative earnings	22	—	214	—	236
Other, net	—	—	91	—	91
Net cash used in investing activities	(923)	—	(2,414)	945	(2,392)
Cash flows from financing activities					
Issuance of debt	2,070	—	7,502	—	9,572
Payment of debt	(1,649)	—	(7,144)	—	(8,793)
Funding from affiliates	1	—	852	(853)	—
Debt issuance costs	(57)	—	(19)	—	(76)
Cash dividends/distributions	(770)	—	—	—	(770)
Distributions to parents	—	—	(1,275)	1,275	—
Contributions from noncontrolling interests	—	—	980	(10)	970
Distributions to noncontrolling interests	—	—	(956)	—	(956)
Other, net	—	—	(4)	—	(4)
Net cash used in financing activities	(405)	—	(64)	412	(57)
Effect of exchange rate changes on cash and cash equivalents	—	—	(8)	—	(8)
Net (decrease) increase in cash and cash equivalents	(371)	—	280	—	(91)
Cash and cash equivalents, beginning of period	373	—	129	—	502
Cash and cash equivalents, end of period	$ 2	$ —	$ 409	$ —	$ 411

Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2013				
Revenues	$ 3,060	$ 3,382	$ 3,756	$ 3,872
Operating Income	1,017	772	1,041	1,160
Income from Continuing Operations	658	781	551	706
Net Income	656	781	551	704
Net Income Attributable to Kinder Morgan, Inc.	292	277	286	338
Class P Shares				
Total Basic and Diluted Earnings Per Common Share	0.28	0.27	0.27	0.33
2012				
Revenues	$ 1,857	$ 2,167	$ 2,870	$ 3,079
Operating Income	516	260	852	965
Income from Continuing Operations	305	37	386	476
(Loss) Income from Discontinued Operations	(378)	(280)	(131)	12
Net (Loss) Income	(73)	(243)	255	488
Net Income (Loss) Attributable to Kinder Morgan, Inc.	21	(126)	200	220
Class P Shares				
Basic and Diluted Earnings (Loss) Per Common Share From Continuing Operations	$ 0.23	$ (0.11)	$ 0.21	$ 0.21
Basic and Diluted Loss Per Common Share From Discontinued Operations	(0.20)	(0.04)	(0.02)	—
Total Basic and Diluted Earnings (Loss) Per Common Share	$ 0.03	$ (0.15)	$ 0.19	$ 0.21
Class A Shares				
Basic and Diluted Earnings (Loss) Per Common Share From Continuing Operations	$ 0.21	$ (0.13)	$ 0.19	$ 0.19
Basic and Diluted Loss Per Common Share From Discontinued Operations	(0.20)	(0.04)	(0.02)	—
Total Basic and Diluted Earnings (Loss) Per Common Share	$ 0.01	$ (0.17)	$ 0.17	$ 0.19

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, 2013, 2012 and 2011 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2013	2012	2011
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$ 18.81	$ 16.44	$ 15.37
Crude oil production (MBbl/d)	37.6	35.0	34.2
SACROC crude oil production (MBbl/d)	25.5	24.1	23.8
Yates crude oil production (MBbl/d)	9.0	9.3	9.6
NGL production (MBbl/d)(d)	4.1	3.9	3.5
NGL production from gas plants(MBbl/d)(e)	5.8	5.6	5.0
Total NGL production(MBbl/d)	9.9	9.5	8.5
SACROC NGL production (MBbl/d)(d)	3.8	3.7	3.3
Yates NGL production (MBbl/d)(d)	0.2	0.2	0.2
Natural gas production (MMcf/d)(d)(f)	1.1	1.2	1.5
Natural gas production from gas plants(MMcf/d)(e)(f)	1.7	0.7	0.5
Total natural gas production(MMcf/d)(f)	2.8	1.9	2.0
Yates natural gas production (MMcf/d)(d)(f)	1.1	1.1	1.4
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$ 92.70	$ 87.72	$ 69.73
NGL price per Bbl(g)	$ 46.11	$ 51.79	$ 65.65
Natural gas price per Mcf(h)	$ 3.23	$ 2.58	$ 3.86
Total NGL price per Bbl(e)	$ 46.43	$ 50.95	$ 65.61
Total natural gas price per Mcf(e)	$ 3.21	$ 2.72	$ 3.76
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$ 94.94	$ 89.91	$ 92.61
NGL price per Bbl(g)	$ 46.11	$ 51.79	$ 65.65
Natural gas price per Mcf(h)	$ 3.23	$ 2.58	$ 3.86

(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 (thousand cubic feet) 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 KMP's 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,		
	2013	2012	2011
Consolidated Companies(a)			
Wells and equipment, facilities and other	$ 4,432	$ 3,927	$ 3,586
Leasehold	660	428	433
Total proved oil and gas properties	5,092	4,355	4,019
Unproved property(b)	38	8	34
Accumulated depreciation and depletion	(3,520)	(3,072)	(2,661)
Net capitalized costs	$ 1,610	$ 1,291	$ 1,392

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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, 2013, capitalized costs related to the unproved property for the Katz Strawn unit, was $20 million, Residual Oil Zone (ROZ) unproved exploration property was $13 million, and other miscellaneous unproved property was $5 million.

For each of the years ended December 31, 2013 , 2012 and 2011, 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,		
	2013	2012	2011
Consolidated Companies			
Acquisitions(a)	$ 285	$ —	$ —
Development(b)	471	310	373
Exploration(c)	11	—	—

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(a) Acquisition of Goldsmith Landreth San Andreas Unit effective June 1, 2013.

(b) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(c) Amounts relate to exploration wells drilled in the Residual Oil Zone (ROZ).

Our results of operations from oil and gas producing activities for each of the years ended December 31, 2013, 2012 and 2011 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2013	**2012**	**2011**
Consolidated Companies(a)			
Revenues(b)	$ 1,376	$ 1,235	$ 993
Expenses:			
Production costs	344	288	246
Other operating expenses(c)	95	77	79
DD&A expenses	415	387	394
Total expenses	854	752	719
Results of operations for oil and gas producing activities	$ 522	$ 483	$ 274

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Revenues include losses attributable to our hedging contracts of $31 million, $28 million and $285 million for each of the years ended December 31, 2013, 2012 and 2011, respectively.

(c) Consists primarily of CO_2 expense.

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 Note 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, other than the reserve estimates for the Goldsmith Landreth San Andreas Unit which we acquired effective June 1, 2013, 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 has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Newton is a Licensed Professional Engineer in the State of Texas (No. 97689) and has over 28 years of practical experience in petroleum engineering, with over 16 years experience in the estimation and evaluation of reserves. 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 has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 24 years experience in the estimation and evaluation of reserves. 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. The proved reserve estimates in NSAI's reserves report constitute approximately 58% of all proved oil and gas reserves owned by KMP.

The reserves estimates for the Goldsmith Landreth San Andreas Unit have been independently evaluated by Ryder Scott Company L.P. (RSC). The proved reserve estimates in RSC's reserves report constitute approximately 42% of all proved oil and gas reserves owned by KMP. RSC is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. These reserve estimates are the result of technical analysis conducted by teams of geoscientists and engineers from RSC. Mr. Michael F. Stell was the primary technical person responsible for overseeing the estimate of the reserves, future production and income. Mr. Stell, an employee of RSC since 1992, is an Advising Senior Vice President and is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining RSC, Mr. Stell served in a number of engineering positions with Shell Oil Company and Landmark Concurrent Solutions. For more information regarding Mr. Stell's geographic and job specific experience, please refer to the RSC website at www.ryderscott.com/Experience/Employees. Mr. Stell earned a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Stell fulfills. For each of the years 2011 through 2013, Mr. Stell has 20 hours of continuing education hours relating to reserves, reserve evaluations, and ethics. Based on his educational background, professional training and over 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Stell has attained the professional qualifications for a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

Our employee who is primarily responsible for overseeing both NSAI and RSC'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-KMP 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-KMP business segment reports independently of our four 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, 2013.

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, 2011, we had 55.7 MMBbl of crude oil and 1.8 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2011, we had 23.8 MMBbl of crude oil and 2.3 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2011, were 79.4 MMBbl of crude oil and 4.1 MMBbl of NGL.

During 2012, production from the fields totaled 12.8 MMBbl of crude oil and 1.4 MMBbl of NGL. In addition, we incurred $353 million in capital costs, which resulted in the development of 6.0 MMBbl of crude oil and 1.8 MMBbl of NGL and their transfer from the proved undeveloped category to the proved developed category. During 2012, we also sold our interest in the Claytonville Canyon Sand unit which reduced proved developed reserves by 0.2 MMBbl of crude oil. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 25.4% of crude oil and 79.4% of NGL from the proved undeveloped reserves reported as of December 31, 2011 to the proved developed classification of reserves reported as of December 31, 2012.

Also during 2012, previous estimates of proved developed reserves were revised upwards by 4.3 MMBbl of crude oil and 0.2 MMBbl of NGL, and proved undeveloped reserves were revised upward by 11.2 MMBbl of crude oil and 3.0 MMBbl of NGL. These revisions were attributed to utilizing higher projected CO_2 flood recoveries resulting from updated performance at SACROC used to calculate reserves. There were 2.6 MMBbl of crude oil reserves attributed to future development of the Katz (Strawn) unit CO_2 flood where the produced gas containing NGL is injected with the CO_2. The proved undeveloped reserves for the Katz (Strawn) unit CO_2 flood represent 9.0% of proved undeveloped reserves.

These revisions to the 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 31.0% at year end 2011 to 36.4% at year end 2012. After giving effect to production and revisions to previous estimates during 2012, total proved reserves of crude oil increased by 2.5 MMBbl and total proved reserves of NGL increased by 1.8 MMBbl.

As of December 31, 2012, we had 53.0 MMBbl of crude oil and 2.4 MMBbl of NGL classified as proved developed reserves. Also, as of year end 2012, we had 28.9 MMBbl of crude oil and 3.5 MMBbl of NGL classified as proved undeveloped reserves. Total proved reserves as of December 31, 2012, were 82.0 MMBbl of crude oil and 6.0 MMBbl of NGL.

During 2013, production from the fields totaled 13.7 MMBbl of crude oil and 1.5 MMBbl of NGL. For 2013, we incurred $452 million in capital costs, and this capital investment resulted in the development of 11.0 MMBbl of crude oil and 1.3 MMBbl of NGL and their transfer from the proved undeveloped category to the proved developed category. During 2013, we acquired the Goldsmith Landreth San Andres Field Unit which increased proved developed reserves by 15.5 MMBbl of crude oil and 3.9 MMBbl of NGL. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 38.1% of crude oil and 37.5% of NGL from the proved undeveloped reserves reported as of December 31, 2012 to the proved developed classification of reserves reported as of December 31, 2013. The developed reserves for the Goldsmith Landreth San Andres Field Unit represent 25.9% of proved developed reserves.

Also during 2013, previous estimates of proved developed reserves were revised upward by 1.7 MMBbl of crude oil and 0.6 MMBbl of NGL, and proved undeveloped reserves were revised downward by 4.3 MMBbl of crude oil and 0.65 MMBbl of NGL. These revisions are mainly attributed to the elimination of uneconomic proved developed nonproducing reserves and proved undeveloped reserves in Katz due to higher operating costs. The proved developed reserves for Katz represent 6.3% 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 36.4% at year end 2012 to 39.0% at year end 2013. After giving effect to production and revisions to previous estimates during 2013, total proved reserves of crude oil increased by 25.1 MMBbl and total proved reserves of NGL increased by 8.8 MMBbl.

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. We currently expect that the proved undeveloped reserves we report as of December 31, 2013 will be developed within the next five years.

During 2013, we filed estimates of our oil and gas reserves for the year 2012 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 Note exceeds 5%.

The following Reserve Quantity Information table discloses estimates, as of December 31, 2013, of proved crude oil, NGL and natural gas reserves, prepared by NSAI and RSC (independent oil and gas consultants), of KMCO $_2$ 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 Note 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, 2010	84,176	4,863	3,098
Revisions of previous estimates(c)	4,719	567	687
Improved recovery(d)	3,018	—	—
Production	(12,466)	(1,285)	(544)
As of December 31, 2011	79,447	4,145	3,241
Revisions of previous estimates(e)	15,540	3,285	4,881
Extensions and Discoveries	26	—	—
Sales of Reserves in Place	(239)	(38)	(143)
Production	(12,824)	(1,416)	(440)
As of December 31, 2012	81,950	5,976	7,539
Revisions of previous estimates(f)	(2,573)	(43)	(5,063)
Purchases of Reserves in Place(g)	41,389	10,347	—
Production	(13,735)	(1,499)	(406)
As of December 31, 2013	107,031	14,781	2,070
Proved developed reserves:(h)			
As of December 31, 2011	55,652	1,823	3,241
As of December 31, 2012	53,006	2,433	7,539
As of December 31, 2013	67,436	6,733	2,070
Proved undeveloped reserves:(i)			
As of December 31, 2011	23,795	2,322	—
As of December 31, 2012	28,944	3,543	—
As of December 31, 2013	39,595	8,048	—

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(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 product prices used to determine reserve volumes.
(d) Represents volumes added with the development of the Katz (Strawn) unit CO $_2$ flood.
(e) Predominantly due to higher CO $_2$ flood recoveries based on updated performance at the SACROC Unit.
(f) Predominantly due to higher operating costs at the Katz Strawn Unit.
(g) Represents volumes added with acquisition of the Goldsmith Landreth San Andreas Unit in June 2013.
(h) Proved developed reserves include reserves attributable to the Goldsmith Landreth San Andreas Unit of 15,450 MBbl for oil and 3,862 MBbl for NGL's.
(i) Proved undeveloped reserves include reserves attributable to the Goldsmith Landreth San Andreas Unit of 25,935 MBbl for oil and 6,484 MBbl for NGL's.

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:

- 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,		
	2013	**2012**	**2011**
Consolidated Companies(a)			
Future cash inflows from production	$ 10,945	$ 7,807	$ 7,648
Future production costs	(4,214)	(2,923)	(2,806)
Future development costs(b)	(1,948)	(1,011)	(1,443)
Undiscounted future net cash flows	4,783	3,873	3,399
10% annual discount	(2,096)	(1,168)	(1,205)
Standardized measure of discounted future net cash flows(c)	$ 2,687	$ 2,705	$ 2,194

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Includes abandonment costs.

(c) Standardized Measure of discounted future net cash flows as of December 31, 2013 includes $843 million attributable to the Goldsmith Landreth San Andreas Unit acquired in June 2013.

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,		
	2013	**2012**	**2011**
Consolidated Companies(a)			
Present value as of January 1	$ 2,705	$ 2,194	$ 1,898
Changes during the year:			
Revenues less production and other costs(b)	(965)	(895)	(949)
Net changes in prices, production and other costs(b)	258	(88)	697
Development costs incurred	452	353	416
Net changes in future development costs	(629)	64	(317)
Improved recovery	—	—	10
Extensions and Discoveries(c)	—	5	—
Sales of Reserves in Place(d)	—	(5)	—
Revisions of previous quantity estimates(e)	(114)	871	257
Purchase of Reserves in Place(f)	683	—	—
Accretion of discount	297	206	182
Net change for the year	(18)	511	296
Present value as of December 31(g)	$ 2,687	$ 2,705	$ 2,194

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(a) Amounts relate to $KMCO_2$ and its consolidated subsidiaries.

(b) Excludes the effect of losses attributable to our hedging contracts of $31 million, $28 million and $285 million for each of the years ended December 31, 2013, 2012 and 2011, respectively.

(c) Primarily due to the extension of the SACROC unit.

(d) Sale of the Claytonville field unit.

(e) 2013 revisions were primarily due to increased operating costs at the Katz Strawn Unit. 2012 revisions were primarily due to higher projected CO_2 flood recoveries resulting from updated performance at SACROC and the addition of proved undeveloped reserve volumes at the Katz (Strawn) unit CO_2 flood. 2011 revisions were primarily due to higher product prices used to determine reserve volumes and the addition of the Katz (Strawn) unit CO_2 flood.

(f) Acquisition of the Goldsmith Landreth San Andreas Unit in June 2013.

(g) Standardized Measure discounted cash flows as of December 31, 2013 includes $843 million attributable to the Goldsmith Landreth San Andreas Unit acquired in June 2013.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 21, 2014

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.

Table of Contents

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 21, 2014
/s/ RICHARD D. KINDER Richard D. Kinder	Director, Chairman and Chief Executive Officer (principal executive officer)	February 21, 2014
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 21, 2014
/s/ STEVEN J. KEAN Steven J. Kean	Director	February 21, 2014
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 21, 2014
/s/ MICHAEL MILLER Michael Miller	Director	February 21, 2014
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 21, 2014
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 21, 2014
/s/ C. PARK SHAPER C. Park Shaper	Director	February 21, 2014
/s/ JOEL V. STAFF Joel V. Staff	Director	February 21, 2014
John Stokes	Director	
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 21, 2014

Representing a majority of the Board of Directors of Kinder Morgan, Inc.

Exhibit 12.1

KINDER MORGAN, INC. AND SUBSIDIARIES

EXHIBIT 12.1 - STATEMENT RE: COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in millions except ratio amounts)

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings:					
Pre-tax income from continuing operations before cumulative effect of a change in accounting principle and before adjustment for noncontrolling interests and equity earnings (including amortization of excess cost of equity investments) per statements of income	$ 3,150	$ 1,213	$ 591	$ 510	$ 730
Add:					
Fixed charges	1,785	1,486	766	704	656
Amortization of capitalized interest	6	5	5	4	4
Distributed income of equity investees	398	311	200	132	128
Less:					
Interest capitalized from continuing operations	(52)	(27)	(15)	(13)	(33)
Noncontrolling interest in pre-tax income of subsidiaries with no fixed charges	392	17	(22)	(107)	(83)
Income as adjusted	$ 5,679	$ 3,005	$ 1,525	$ 1,230	$ 1,402
Fixed charges:					
Interest and debt expense, net per statements of income (includes amortization of debt discount, premium, and debt issuance costs; excludes capitalized interest)	$ 1,742	$ 1,454	$ 718	$ 681	$ 632
Add:					
Portion of rents representative of the interest factor	43	32	48	23	24
Fixed charges	$ 1,785	$ 1,486	$ 766	$ 704	$ 656
Ratio of earnings to fixed charges	3.18	2.02	1.99	1.75	2.14

Exhibit 21.1

Kinder Morgan, Inc.

Subsidiaries of the Registrant

Kinder Morgan (Delaware), Inc.
Kinder Morgan G. P., Inc.
Kinder Morgan Energy Partners, L.P.
KN Telecommunications, Inc.
Kinder Morgan Foundation (nonprofit)
K N Gas Gathering, Inc.
Horizon Pipeline Company, L.L.C. (50%)
Kinder Morgan Insurance Ltd.
Kinder Morgan Illinois Pipeline LLC
NGPL PipeCo LLC
Knight Power Company LLC
NGPL HoldCo Inc.
Natural Gas Pipeline Company of America LLC
Kinder Morgan Finance Company LLC
Kinder Morgan Canada LLC
NGPL Holdco LLC
Midco LLC
El Paso Holdco LLC
KMGP Contracting Services LLC

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on (i) Form S-3 (Nos. 333-179812, 333-179813 and 333-179814) and (ii) Form S-8 (Nos. 333-172170, 333-172582, 333-172584, 333-172606, 333-172808 and 333-181782) of Kinder Morgan, Inc. of our report dated February 21, 2014 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As oil and gas consultants, we hereby consent to the use of our name and our report dated January 6, 2014, in this Form 10-K, incorporated by reference into Kinder Morgan Energy Partners, L.P.'s previously filed Registration Statements on (i) Form S-3 (Nos. 333-124471, 333-142584, 333-167562, 333-171864, 333-179377, 333-179813-02, 333-179814-02, 333-181811, 333-188071, and 333-189697) and (ii) Form S-8 (Nos. 333-56343 and 333-122168).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simmons
By:
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 7, 2014

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As oil and gas consultants, we hereby consent to the use of our name and our report dated January 3, 2014, in this Form 10-K, incorporated by reference into Kinder Morgan Energy Partners, L.P.'s previously filed Registration Statements on (i) Form S-3 (Nos. 333-124471, 333-142584, 333-167562, 333-171864, 333-179377, 333-179813-02, 333-179814-02, 333-181811, 333-188071 and 333-189697) and (ii) Form S-8 (Nos. 333-56343 and 333-122168).

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 3, 2014

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As oil and gas consultants, we hereby consent to the use of our name and our report dated January 15, 2014, in this Form 10-K, incorporated by reference into Kinder Morgan Energy Partners, L.P.'s previously filed Registration Statements on (i) Form S-3 (Nos. 333-124471, 333-142584, 333-167562, 333-171864, 333-179377, 333-179813-02, 333-179814-02, 333-181811, 333-188071 and 333-189697) and (ii) Form S-8 (Nos. 333-56343 and 333-122168).

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
February 3, 2014

Exhibit 31.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION 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

I, Richard D. Kinder, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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 in the United States;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial information.

Date: February 21, 2014

/s/ RICHARD D. KINDER
Richard D. Kinder
Chairman and Chief Executive Officer

Exhibit 31.2

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION 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

I, Kimberly A. Dang, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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 in the United States;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial information.

Date: February 21, 2014

/s/ KIMBERLY A. DANG

Kimberly A. Dang
Vice President and Chief Financial Officer

Exhibit 32.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2014

/s/ RICHARD D. KINDER
Richard D. Kinder
Chairman and Chief Executive Officer

Exhibit 32.2

KINDER MORGAN, INC.
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 21, 2014

/s/ KIMBERLY A. DANG
Kimberly A. Dang
Vice President and Chief Financial Officer

Exhibit 95.1

KINDER MORGAN, INC. AND SUBSIDIARIES

EXHIBIT 95.1 – MINE SAFETY DISCLOSURES

This exhibit contains 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. The following table provides information about citations, orders and notices issued under the Federal Mine Safety and Health Act of 1977 (the "Mine Act") by the federal Mine Safety and Health Administration ("MSHA") for our mines during the year ended December 31, 2013.

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110(b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern of Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
1103225 Cahokia	—	—	—	—	—	$ 200	—	No	No	—	1	1
1103224 Kellogg	—	—	—	—	—	$ —	—	No	No	—	—	—
1103140 Cora	—	—	—	—	—	$ —	—	No	No	—	—	—
1518234 Grand Rivers	—	—	—	—	—	$ —	—	No	No	2	1	1

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As of February 25, 2013, 1103224-Kellogg Terminal, ceased blending coal and currently is de-active under MSHA jurisdiction.

As of May 9, 2013, 1103140-Cora Terminal, ceased blending coal and currently is de-active under MSHA jurisdiction.

The dollar value represents the total dollar value of all MSHA citations issued and assessed for the four terminals noted above. The value includes S&S and non-S&S citations issued during calendar year 2013. The dollar value represents citations paid, pending payment, and citations in contest as of December 31, 2013.

The MSHA citations, orders and assessments reflected above are those initially issued or proposed by MSHA. They do not reflect subsequent changes in the level of severity of a citation or order or the value of an assessment that may occur as a result of proceedings conducted in accordance with MSHA rules.

As of December 31, 2013, there were no pending legal actions before the Federal Mine Safety and Health Review Commission involving any of our mines other than actions filed under the following docket numbers (all of which are contests of citations or orders under Section 104 of the Mine Act):

1518234-Grand Rivers Terminal: Filings “Open” status

- Docket KENT 2012-1562
- Docket KENT 2012-1561

During the year ended December 31, 2013, the following legal actions before the Federal Mine Safety and Health Review Commission involving our mines were resolved:

1518234-Grand Rivers Terminal

- Docket KENT 2013-59

1103225-Cahokia Terminal

- Docket LAKE 2013-402

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a) and
the 2007 Petroleum Resources Management System Approved by the Society of Petroleum Engineers

January 6, 2014

Dr. Lanny G. Schoeling
Kinder Morgan CO_2 Company, L.P.
1001 Louisiana Street, Suite 1000
Houston, Texas 77002

Dear Dr. Schoeling:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Kinder Morgan CO_2 Company, L.P. (Kinder Morgan) interest in certain oil and gas properties located in Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 58 percent of all proved reserves owned by Kinder Morgan. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Kinder Morgan Energy Partners, L.P.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Kinder Morgan interest in these properties, as of December 31, 2013, to be:

Category	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Future Net Revenue (M$) Total	Present Worth at 10%
Proved Developed Producing	51,986.1	2,870.5	2,069.5	2,313,477.6	1,698,150.8
Proved Developed Non-Producing [(1)]	0.0	0.0	0.0	0.0	0.0
Proved Undeveloped	13,659.6	1,564.4	0.0	266,294.0	145,575.0
Total Proved	65,645.7	4,434.9	2,069.5	2,579,771.6	1,843,725.8

(1) There are no proved developed non-producing reserves at the prices and costs used in this report.

The oil volumes shown include crude oil only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. No study was made to determine whether probable or possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Kinder Morgan's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Kinder Morgan's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil and NGL volumes, the average West Texas Intermediate posted price of $93.42 per barrel is adjusted by field for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.670 per MMBTU is adjusted by field for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $95.36 per barrel of oil, $45.53 per barrel of NGL, and $3.810 per MCF of gas.

Operating costs used in this report are based on operating expense records of Kinder Morgan. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Kinder Morgan's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, per-unit-of-production costs, and per-unit-of-injection costs. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Kinder Morgan and are based on its internal planning budgets and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Kinder Morgan's estimates of the costs to abandon the wells and production facilities;

these estimates do not include any salvage value for the lease and well equipment. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Kinder Morgan interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Kinder Morgan receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and for properties that rely on continued CO_2 injection; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Kinder Morgan, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:	/s/ Derek F. Newton By: Derek F. Newton, P.E. 97689 Vice President	/s/ Mike K. Norton Mike K. Norton, P.G. 441 Senior Vice President

Date Signed: January 6, 2014 Date Signed: January 6, 2014

DFN:JLM

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4 -10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

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(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

- (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

  - (A) Costs of labor to operate the wells and related equipment and facilities.
  - (B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological,

geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for

hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects - such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations - by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company's historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;

The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Kinder Morgan CO_2 Company L.P.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2013

/s/ Michael F. Stell	/s/ Moksh Dani
Michael F. Stell, P.E.	Moksh Dani, P.E.
TBPE License No. 56416	TBPE License No. 112777
Advising Senior Vice President	Senior Petroleum Engineer

[SEAL] [SEAL]

RYDER SCOTT COMPANY, L.P.

TBPE Firm Registration No. F-1580

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790

621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849

1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 3, 2014

Kinder Morgan CO_2 Company L.P.
1001 Louisiana Street, Suite 1000
Houston, TX 77002

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Kinder Morgan CO_2 Company L.P. (Kinder Morgan) as of December 31, 2013. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009, in the Federal Register (SEC regulations). Our third party study, completed on December 31, 2013, and presented herein, was prepared for public disclosure by Kinder Morgan in flings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 42 percent of the total net proved liquid hydrocarbon reserves and zero percent of the total net proved gas reserves of Kinder Morgan as of December 31, 2013. The properties evaluated by Ryder Scott represent 42 percent of the total net proved BOE reserves of Kinder Morgan as of December 31, 2013.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2013 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered

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in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Kinder Morgan CO_2 Company L.P.

As of December 31, 2013

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Remaining Reserves			
Oil/Condensate - MBBL	15,450	25,935	41,385
Plant Products - MBBL	3,862	6,484	10,346
Income Data (M$)			
Future Gross Revenue	$1,596,187	$2,714,865	$4,311,052
Deductions	838,291	1,269,734	2,108,025
Future Net Income (FNI)	$ 757,896	$1,445,131	$2,203,027
Discounted FNI @ 10%	$ 439,997	$ 403,272	$ 843,269

Liquid hydrocarbons are expressed as thousands of standard 42 gallon barrels (MBBL). The net remaining reserves are referenced above on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. BOE means barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used at the request of Kinder Morgan. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes and processing fee (negative other revenue). The deductions incorporate the normal direct costs of operating the wells, purchasing and recycling CO_2 costs, net profits interest payment (other cost column), ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for all of total future gross revenue from proved reserves.

For the purposes of this report and based on information supplied by Kinder Morgan, the effect of the net profit interests does not result in a reduction of the net reserves, but is treated as a financial obligation and shown as an "Other Deduction" in our projections. You should be aware, however, that the petroleum engineers employed by the U.S. Securities and Exchange Commission (SEC) have recently taken a position whereby NPI are to be assigned proportionate amounts of reserves. Should this issue be questioned, we have estimated that the volume of “cost-free” proved net reserves associated with the NPI would be 3,100 MBBLS of oil.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income (M$) As of December 31, 2013
Discount Rate Percent	Total Proved
5	$1,331,659
15	$ 553,947
20	$ 373,985
25	$ 257,270

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report. The various proved reserve status categories are defined under the attachment entitled “Petroleum Reserves Status Definitions and Guidelines” in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kinder Morgan’s request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Kinder Morgan's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kinder Morgan owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. In general, reserves attributable to producing wells and/or reservoirs were estimated by performance methods such as decline curve analysis and/or material balance which utilized extrapolations of historical production and pressure data available through December 2013 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Kinder Morgan or obtained from public data sources and were considered sufficient for the purpose thereof. In certain cases, producing reserves were estimated by the volumetric method where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

Proved undeveloped reserves included herein were estimated by the volumetric method and analogy methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kinder Morgan. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

It should be noted that proved undeveloped reserves for a CO_2 flood in the Goldsmith Landreth Unit (Goldsmith Field) account for 63 percent of the reserves included herein. These reserves were based on volumetric oil-in-place volumes for both the Main Pay and Residual Oil Zone intervals for this project estimated and provided by Kinder Morgan and reviewed by Ryder Scott. Nearby pilots or similar established improved recovery CO_2 projects in the Permian Basin area in which the Goldsmith Field is located, were used to determine the appropriate recovery of the oil-in-place volumes.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kinder Morgan has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kinder Morgan with respect to property interests, production and well tests, normal direct costs, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kinder Morgan. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Kinder Morgan. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Kinder Morgan furnished us with the above mentioned average prices in effect on December 31, 2013. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Kinder Morgan. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Kinder Morgan to determine these differentials

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil	WTI Posting (Plains)	$93.42/Bbl	$94.67/Bbl
	NGLs	WTI Posting (Plains)	$93.42/Bbl	$94.67/Bbl*

* NGL’s are blended into the oil and sold as one oil stream

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Kinder Morgan and are based on the operating expense reports of Kinder Morgan and include only those costs directly applicable to the leases or wells, and CO_2 reinjection expenses. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. Other costs shown in this report include the net profits interest payment to Exxon starting in March 2020. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Kinder Morgan and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. Purchased CO_2 costs are also included in the development and operating costs. Kinder Morgan’s estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Kinder Morgan’s estimate.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Kinder Morgan’s plans to develop these reserves as of December 31, 2013. The implementation of Kinder Morgan’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Kinder Morgan’s management. As the result of our inquiries during the course of preparing this report, Kinder Morgan has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kinder Morgan’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kinder Morgan. Additionally, Kinder Morgan has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Kinder Morgan. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations.

Kinder Morgan makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kinder Morgan has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3, Form S-3ASR, and Form S-8 of Kinder Morgan of the references to our name as well as to the references to our third party report for Kinder Morgan, which appears in the December 31, 2013 annual report on Form 10-K of Kinder Morgan. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kinder Morgan.

We have provided Kinder Morgan with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kinder Morgan and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

TBPE Firm Registration No. F-1580

/s/ Michael F. Stell

Michael F. Stell, P.E.
TBPE License No. 56416
Advising Senior Vice President

[SEAL]

/s/ Moksh Dani

Moksh Dani, P.E.
TBPE License No. 112777
Senior Petroleum Engineer

[SEAL]

MFS-MD (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Michael F. Stell was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Mr. Stell, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1992, is an Advising Senior Vice President and is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Stell served in a number of engineering positions with Shell Oil Company and Landmark Concurrent Solutions. For more information regarding Mr. Stell's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Stell earned a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Stell fulfills. As part of his 2009 continuing education hours, Mr. Stell attended an internally presented 13 hours of formalized training as well as a day-long public forum relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Stell attended an additional 15 hours of formalized in-house training as well as an additional five hours of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. As part of his 2010 continuing education hours, Mr. Stell attended an internally presented six hours of formalized training and ten hours of formalized external training covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, evaluation of enhanced oil recovery reserves, and ethics training. For each year starting 2011 through 2013, as of the date of this report, Mr. Stell has 20 hours of continuing education hours relating to reserves, reserve evaluations, and ethics.

Based on his educational background, professional training and over 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Stell has attained the professional qualifications for a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*

(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.