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, 2012

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: 1-11234

Kinder Morgan Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0380342**
(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
Common Units	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 [X] 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 [X]

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 [X] 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

Table of Contents

chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] 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. [X]

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 [X] 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 [X]

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 29, 2012 was approximately $17,538,123,334. As of January 31, 2013, the registrant had 252,756,425 Common Units outstanding.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
TABLE OF CONTENTS

PART I

Items 1 and 2. *Business and Properties.*

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to "we," "us," "our," "KMP" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P., our operating limited partnerships and their majority-owned and controlled subsidiaries. We own an interest in or operate approximately 46,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described more fully below in "-(c) Narrative Description of Business-Business Segments").

Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals, and handle such products as ethanol, coal, petroleum coke and steel. We are also the leading producer and transporter of carbon dioxide, commonly called CO_2, for enhanced oil recovery projects in North America. 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.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto included elsewhere in this report. We have prepared our accompanying consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission, referred to as the SEC. Our accounting records are maintained in United States dollars, and all references to dollars in this report are to United States dollars, except where stated otherwise. Canadian dollars are designated as C$. Our consolidated financial statements include our accounts and those of our operating limited partnerships and their majority-owned and controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation.

(a) General Development of Business

Organizational Structure

We are a Delaware limited partnership formed in August 1992, and our common units, which represent limited partner interests in us, trade on the New York Stock Exchange under the symbol "KMP." In general, our limited partner units, consisting of common units, Class B units (the Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange) and i-units, will vote together as a single class, with each common unit, Class B unit, and i-unit having one vote. Our partnership agreement requires us to distribute all of our available cash, as defined in our partnership agreement, to our partners on a quarterly basis within 45 days after the end of each calendar quarter. We pay our quarterly distributions to our common unitholders, our sole Class B unitholder and our general partner in cash, and we pay our quarterly distributions to our sole i-unitholder in additional i-units rather than in cash. For further information about our distributions, see Note 11 "Related Party Transactions-Partnership Interests and Distributions" to our consolidated financial statements included elsewhere in this report.

Kinder Morgan, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation referred to as KMI in this report, indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation; however, in July 2007, our general partner issued and sold to a third party 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC. KMI's common stock trades on the New York Stock Exchange under the symbol "KMI."

Effective on May 25, 2012, KMI completed the acquisition of all of the outstanding shares of El Paso Corporation, referred to as "EP." EP owns one of North America's largest interstate natural gas pipeline systems and an emerging midstream business. EP also owns a 41% limited partner interest and the 2% general partner interest in El Paso Pipeline Partners, L.P. and this EP acquisition created one of the largest energy companies in the United States.

As of December 31, 2012, KMI and its consolidated subsidiaries owned, through KMI's general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 12.8% interest in us. In addition to the distributions it receives from its limited and general partner interests, KMI also receives an incentive distribution from us as a result of its ownership of our general partner. Including both its general and limited partner interests in us, at the 2012 distribution level, KMI received approximately 51% of all quarterly distributions of available cash from us, with approximately 45% and 6% of all quarterly distributions from us attributable to KMI's general partner and limited partner interests, respectively.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company formed in February 2001. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. KMR's shares represent limited liability company interests and trade on the New York Stock Exchange under the symbol "KMR."

Under the delegation of control agreement, KMR, as the delegate of our general partner, manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their majority-owned and controlled subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their majority-owned and controlled subsidiaries. As of December 31, 2012, KMR, through its sole ownership of our i-units, owned approximately 30.8% of all of our outstanding limited partner units.

Recent Developments

The following is a brief listing of significant developments since December 31, 2011. We begin with developments pertaining to our reportable business segments. Additional information regarding most of these items may be found elsewhere in this report.

Products Pipelines

- In August 2012, we and Valero Energy Corporation began construction on our previously announced Parkway Pipeline, a new 141-mile, 16-inch diameter pipeline that will transport refined petroleum products from refineries located in Norco, Louisiana, to Plantation Pipe Line Company's (our approximately 51%-owned equity investee) petroleum transportation hub located in Collins, Mississippi. We have substantially completed the Lake Pontchartrain portion of the pipeline, and construction activities continue on land in Louisiana and Mississippi. Upon completion, we will operate and own a 50% equity interest in the Parkway Pipeline, which will have an initial capacity of 110,000 barrels per day, with the ability to expand to over 200,000 barrels per day. The pipeline project is supported by a long-term throughput agreement with a credit-worthy shipper and is scheduled to be in service in September 2013;

- On August 23, 2012, we announced that we would invest approximately $90 million to build a 27-mile, 12-inch diameter lateral pipeline that will extend our Kinder Morgan crude oil/condensate pipeline to Phillips 66's Sweeny refinery located in Brazoria County, Texas. We will provide Phillips 66 with a significant portion of the lateral's initial capacity of 30,000 barrels per day, which is expandable to 100,000 barrels per day. We will also add associated receipt facilities by constructing a five-bay truck offloading facility and three new storage tanks with approximately 360,000 barrels of crude oil/condensate capacity at stations located in DeWitt and Wharton counties in Texas. We began construction in December 2012. We expect to place the lateral into initial service at the beginning of the fourth quarter of 2013, and we expect the entire system to be operational by year-end 2013;

- In October 2012, we began transporting crude oil and condensate volumes on previously announced Kinder Morgan crude oil/condensate pipeline, which transports available crude oil and condensate capacity from the production area in the Eagle Ford shale gas formation in South Texas to the Houston Ship Channel. The approximately $213 million pipeline, which has a capacity of 300,000 barrels per day, was completed on time and under budget, and is supported by long-term contractual commitments. The pipeline consists of approximately 65 miles of new pipeline construction and 109 miles of converted natural gas pipeline, and it delivers product to multiple terminaling facilities that provide access to local refineries, petrochemical plants and docks along the Texas Gulf Coast;

- In December 2012, we completed our previously announced refined petroleum products storage expansion project at our West Coast Terminals' Carson, California products terminal. The approximately $77 million expansion project added seven storage tanks with a combined capacity of 560,000 barrels. We completed and placed into service the first two storage tanks in October 2011, and the remaining five tanks in the third and fourth quarters of 2012. The project was completed on budget and ahead of schedule, and all seven tanks have been leased under long-term agreements with large

U.S. oil refiners;

- By year-end 2012, we also completed facility modifications to provide for the receipt, storage and blending of biodiesel at our Las Vegas, Nevada; Phoenix, Arizona; and Fresno, California terminals. We began blending operations at all three terminals by the end of January 2013;

- As of the date of this report, we continue design and pre-construction activities for our approximately $200 million petroleum condensate processing facility located near our Galena Park terminal on the Houston Ship Channel. The facility, which is supported by a fee-based contract with BP North America, has an anticipated throughput capacity of about 50,000 barrels per day and can be expanded to process 100,000 barrels per day. We expect the facility to be in service in the first quarter of 2014. In light of the growth of Eagle Ford shale natural gas liquids production and the associated need for additional condensate processing capacity, we expect to obtain additional customer commitments to underwrite an expansion at this facility; and

- As of the date of this report, we are in the final permitting stage for our previously announced Cochin Pipeline reversal project, which will allow us to offer a new service to move light condensate from Kankakee County, Illinois to existing terminal facilities located near Fort Saskatchewan, Alberta, Canada. We received more than 100,000 barrels per day of binding commitments (meaning the project was oversubscribed) for a minimum ten-year term during a successful open season that we completed on May 31, 2012. Due to capacity limitations and the need to reserve some capacity for spot shipments, shippers' requests were allocated to a total of 85,000 barrels per day of firm capacity. The approximately $260 million project involves both modifying the Western leg of our Cochin Pipeline to Fort Saskatchewan from a point of interconnection with Explorer Pipeline Company's pipeline in Kankakee County, and building a one million barrel tank farm and associated piping at the Kankakee County point of interconnection. Subject to the timely receipt of necessary regulatory approvals, light condensate shipments could begin as early as July 1, 2014.

Natural Gas Pipelines

- Effective November 1, 2012, KMI sold our FTC Natural Gas Pipelines disposal group to Tallgrass Energy Partners, L.P. for approximately $1.8 billion (before selling costs) to satisfy terms of a March 15, 2012 agreement with the U.S. Federal Trade Commission (FTC) to divest certain of our assets in order to receive regulatory approval for its EP acquisition. Our FTC Natural Gas Pipelines disposal group's assets included our (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. In this report, we refer to this combined group of assets as our FTC Natural Gas Pipelines disposal group. We recognized a combined $829 million loss from both the remeasurement and sale of net assets. Pursuant to current accounting principles, we reclassified and reported the FTC Natural Gas Pipelines disposal group's results of operations as discontinued operations for all periods presented in this report. For more information about this divestiture, see Note 3 to our consolidated financial statements included elsewhere in this report;

- On June 1, 2012, we acquired a 50% equity ownership interest in El Paso Midstream Investment Company, LLC, referred to in this report as EPMIC, from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. for an aggregate consideration of $289 million in common units. The remaining 50% of the joint venture is owned by KMI, which it acquired as part of its acquisition of EP on May 25, 2012. EPMIC owns 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 system located in the Eagle Ford shale formation in South Texas. Additionally, KMI has offered to sell both its 50% ownership interest in EPMIC and its 50% ownership interest in the El Paso Natural Gas pipeline system (discussed following) to us in 2013 (in a future drop-down transaction);

- On August 1, 2012, we acquired the full ownership interest in the Tennessee Gas natural gas pipeline system and a 50% ownership interest in the El Paso Natural Gas pipeline system from KMI for an aggregate consideration of approximately $6.2 billion, consisting of the combined amount of cash paid, common units issued and debt assumed. In this report, we refer to this acquisition of assets from KMI as the drop-down transaction; the combined group of assets acquired from KMI as the drop-down asset group; the Tennessee Gas natural gas pipeline system or Tennessee Gas Pipeline Company, L.L.C. as TGP, and the El Paso Natural Gas pipeline system or El Paso Natural Gas Pipeline Company, LLC as EPNG.

  KMI acquired the drop-down asset group as part of its acquisition of EP on May 25, 2012, and current accounting principles require us to account for the drop-down transaction as a transfer of net assets between entities under common control. Accordingly, we prepared our consolidated financial statements and the related financial information contained in this report to reflect the transfer of the drop-down asset group from KMI to us as if such transfer had taken place on

Table of Contents

May 25, 2012. For further information about the drop-down transaction, see Note 3 to our consolidated financial statements included elsewhere in this report;

- On October 1, 2012, following approval by the Federal Energy Regulatory Commission (FERC), TGP placed in service a portion of its approximately $55 million Northeast Supply Diversification project to support interim customer capacity requirements. The fully subscribed project provides a bi-directional meter on the Niagara Spur with approximately six miles of pipeline looping on TGP's system. Fully placed in service in November 2012, the project creates an additional approximately 245 million cubic feet per day of firm service capacity from the Marcellus shale region along TGP's system to serve existing markets in New England and the Niagara Falls area of New York;

- On October 10, 2012, TGP filed a certificate application with the FERC, proposing its Rose Lake expansion project, which would provide long-term firm natural gas transportation service for two shippers that have fully subscribed approximately 225 million cubic feet per day of firm capacity offered in TGP's Zone 4 in Pennsylvania. The capacity was offered in a binding open season held in the summer of 2012. TGP proposes to retire older compressor units, add new, more efficient and cleaner burning units, and make other modifications involving three existing compressor stations that serve its 300 Line, all located in northeastern Pennsylvania. The anticipated in service date for the approximately $92 million project is November 1, 2014;

- In the fourth quarter of 2012, our wholly-owned subsidiary Sierrita Gas Pipeline LLC (a newly created interstate natural gas pipeline company) entered into a 25-year transportation agreement in connection with plans to build a new pipeline to serve customers in Mexico. Pursuant to the terms of the agreement, Sierrita will construct new facilities that will initially provide approximately 200 million cubic feet per day of firm natural gas transportation capacity via a new 60-mile, 36-inch diameter lateral pipeline that would extend from El Paso Natural Gas Company, L.L.C.'s existing south mainlines (near the City of Tucson, Arizona) to the U.S.-Mexico border (near the Town of Sasabe, Arizona). The proposed $200 million Sierrita Gas Pipeline would interconnect with a new 36-inch diameter natural gas pipeline to be built in Mexico. Sierrita Gas Pipeline LLC filed an application with the FERC on February 7, 2013, and subject to FERC approval, we expect that construction of the Sierrita Pipeline would begin in the first quarter of 2014. We anticipate that the pipeline would be placed into service in the fall of 2014;

- In December 2012, TGP received notices to proceed from the FERC for its proposed approximately $86 million Marcellus Pooling project. The fully subscribed project will provide approximately 240 million cubic feet per day of additional firm transportation capacity from the prolific Marcellus natural gas shale formation. The expansion includes 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. Construction is anticipated to occur primarily this summer and the project is expected to be in service in November of 2013;

- In December 2012, TGP received notices to proceed from the FERC for portions of its proposed approximately $450 million Northeast Upgrade project, and in January 2013, the FERC issued an order denying rehearing of the certificate order and denying requests for stay of the construction. Following issuance of the rehearing order, the U.S. Court of Appeals for the District of Columbia denied motions to stay the FERC certificate and rehearing orders in two separate appeals in February 2013, and authorized construction activities for the project are continuing. The two appeals of the certificate and rehearing orders (which are now consolidated) remain pending before the DC Circuit, but construction activities will continue as those appeals are considered. The Pennsylvania Environmental Hearing Board in January 2013 denied a petition to stay permits for the project issued by the Pennsylvania Department of Environmental Protection, and the U.S. District Court for the Middle District of Pennsylvania issued a preliminary injunction in favor of TGP and enjoining further consideration of the appeal of the permits in February 2013. Additional approvals for the remaining constructions activities in both Pennsylvania and New Jersey are currently pending, however, we anticipate that construction of the mainline pipeline and compressor stations will begin in spring 2013. The fully subscribed project will boost system capacity by approximately 636 million cubic feet per day via five segment loops and system upgrades at four existing compressor stations, and will provide for additional takeaway capacity from the Marcellus shale formation. With no stay of construction granted, and subject to receipt of final FERC and other regulatory agency approval, we expect to complete construction and place the project into service in November 2013; and

- On January 29, 2013, we and Copano Energy, L.L.C., referred to in this report as Copano, announced a definitive agreement whereby we will acquire all of Copano's outstanding units, including convertible preferred units, for a total purchase price of approximately $5 billion, including the assumption of debt. The transaction, which has been approved by the board of directors of both our general partner and Copano, will be a 100% unit for unit transaction with an exchange ratio of 0.4563 of our common units for each Copano unit. The transaction is subject to customary closing conditions, regulatory approvals, and a vote of the Copano unitholders; however, TPG Advisors VI, Inc., Copano's largest unitholder, has agreed to support the transaction and we expect the transaction to close in the third quarter of

2013.

Copano is a midstream natural gas company that provides comprehensive services to natural gas producers, including natural gas gathering, processing, treating and natural gas liquids fractionation. Copano owns an interest in or operates approximately 6,900 miles of pipelines with 2.7 billion cubic feet per day of natural gas transportation capacity, and also owns nine natural gas processing plants with more than 1.0 billion cubic feet per day of natural gas processing capacity and 315 million cubic feet per day of natural gas treating capacity. Its operations are located primarily in Texas, Oklahoma and Wyoming.

CO_2

- On January 18, 2012, we announced an approximately $255 million investment to expand the carbon dioxide capacity of our approximately 87%-owned Doe Canyon Deep unit in southwestern Colorado. The expansion project will include the installation of both primary and booster compression and is expected to increase Doe Canyon's -production rate from 105 million cubic feet of carbon dioxide per day to 170 million cubic feet per day. As of the date of this report, construction continues on both primary and booster compression. We expect to complete and place in service the primary compression in the fourth quarter of 2013, and complete the booster compression in the second quarter of 2014. Additionally, we plan to drill approximately 19 more wells during the next ten years, with one well completed in 2012, and four more wells to be drilled in 2013; and

- On January 31, 2012, we acquired a carbon dioxide source field and related assets located in Apache County, Arizona, and Catron County, New Mexico from a subsidiary of Enhanced Oil Resources for $30 million in cash. The acquisition included all of Enhanced Oil's rights, title, and interest in the carbon dioxide and helium located in the St. Johns gas unit and the Cottonwood Canyon carbon dioxide unit. We refer to this combined group of assets as the St. Johns CO_2 source field, and as of the date of this report, we continue testing wells and performing predevelopment activities. We anticipate that carbon dioxide production from this potential new source field would be transported to the Permian Basin for use by customers in tertiary oil recovery.

Terminals

- On July 17, 2012, we and Peabody Energy announced that we had entered into certain long-term agreements to secure and expand the export platform for Peabody Energy's Colorado, Powder River Basin and Illinois Basin coal products. Pursuant to the provisions of these agreements, Peabody will gain additional access to export coal (i) through 2021 at our Houston Bulk and Deepwater terminal facilities located near Houston; and (ii) through 2020 at our International Marine Terminals facility (IMT), a multi-product, import-export facility located in Myrtle Grove, Louisiana and owned 66 2/3% by us.

  Due to the finalization of these agreements, and to previously announced coal throughput agreements with Arch Coal Company, we are proceeding with Phase 3 of our export coal expansion project at IMT. The Phase 3 project entails adding a new continuous barge unloader, a new reclaim system and an additional 5 million tons of coal storage capacity. We expect the Phase 3 project to be operational in the second quarter 2014. We estimate our share of the total expansion project at IMT (including all phases) will cost approximately $150 million. When completed, our total export coal capacity (for all terminals combined) will be approximately 44.7 million short-tons per year;

- On July 19, 2012, we and BP North America announced the execution of a long-term lease agreement whereby BP will lease an additional 750,000 barrels of refined products capacity at our Galena Park, Texas liquids terminal located on the Houston Ship Channel. BP's products will be processed at the condensate splitter that we are also currently building near the Galena Park facility, and in conjunction with the lease agreement, we agreed to build five new tanks, which will provide storage for BP's product. As of the date of this report, construction continues on our approximately $75 million investment;

- Effective December 1, 2012, TransMontaigne exercised its previously announced option to acquire up to 50% of our Class A member interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO). On this date, TransMontaigne acquired a 42.5% Class A member interest in BOSTCO from us for an aggregate consideration of $79 million, and following this acquisition, we now own a 55% Class A member interest in BOSTCO (we sold a 2.5% Class A member interest in BOSTCO to a third party on January 1, 2012). As of the date of this report, construction continues on the previously announced approximately $430 million BOSTCO oil terminal located on the Houston Ship Channel. The first phase of the project includes construction of 52 storage tanks that will have a capacity of 6.5 million barrels for handling residual fuels, feedstocks, distillates and other black oils. Terminal service agreements or letters of intent have

Table of Contents

been executed with customers for almost all of the capacity. Commercial operations are expected to begin in the third quarter of 2013;

- On January 14, 2013, we announced an expansion project and an acquisition that will provide additional infrastructure to help meet growing demand for liquids storage and dock services along the Texas Gulf Coast. The combined investment will cost approximately $170 million and will include the purchase of 42 acres of land, the construction of a new ship dock to handle ocean going vessels, and the construction of 1.2 million barrels of liquids storage tanks (six 150,000-barrel tanks and four 75,000-barrel tanks). We have entered into a letter of intent with a major oil refiner to develop the tanks with connectivity between our Galena Park liquids terminal and the refiner's Houston Ship Channel refinery. The property will be used to provide dock services for up to eight vessels a month for the refinery and up to four vessels a month for our Galena Park terminal; and

- As of the date of this report, construction also continues on the previously announced Edmonton terminal expansion in Strathcona County, Alberta, Canada. The approximately $310 million phase one project entails building ten tanks with combined new merchant and system tank storage capacity of approximately 3.6 million barrels. The project is expected to be fully completed in December 2013 and is underpinned by long-term commercial agreements with major Canadian oil producers. On January 23, 2013, we announced that we had entered into long-term contracts to support the construction of an additional 1.2 million barrels consisting of four new tanks of merchant storage capacity at the Edmonton terminal. This phase two project is scheduled to commence in the spring of 2013, following receipt of supporting permits, and we expect to complete construction late third quarter of 2014. We estimate this phase two project will cost approximately $112 million, and when complete, will bring total storage capacity at the Edmonton facility to 9.4 million barrels (including the existing Trans Mountain system facility and our North 40 crude oil tank farm).

Kinder Morgan Canada

- On May 23, 2012, our subsidiary Trans Mountain Pipeline L.P. confirmed binding commercial support for its previously announced proposed expansion of our Trans Mountain pipeline system, and on January 10, 2013, Trans Mountain updated the binding commercial support following the completion of a supplemental open season. A total of thirteen companies in the Canadian producing and oil marketing business have signed firm contracts bringing the total volume of committed shippers to approximately 710,000 barrels per day. Trans Mountain is currently in the final stages of securing approval for the commercial terms of this expansion from Canada's National Energy Board, referred to in this report as the NEB. Failure to secure NEB approval of this project at a reasonable toll rate could require us to either delay or cancel this project. We anticipate NEB's approval in the second quarter of 2013.

  Originating in Edmonton, Alberta, our Trans Mountain system is currently designed to carry up to 300,000 barrels per day of crude oil and refined petroleum products to destinations in the northwest United States and on the west coast of British Columbia, and based on the current confirmed shipper response, we would complete the construction of a twin pipeline that could boost system capacity to over 890,000 barrels per day. Trans Mountain plans to file a Facilities Application with the NEB in late 2013, which will seek authorization to build and operate the necessary facilities for the expansion. This filing will initiate a comprehensive regulatory and public review of the proposed expansion. If the application is approved, construction is currently forecast to commence in 2015 or 2016 with the proposed expansion commencing operations in late 2017. Our current estimate of total project construction costs is approximately $5.4 billion; and

- On December 11, 2012, we announced that we had entered into a definitive agreement to sell both our one-third equity ownership interest in the Express pipeline system and our subordinated debt investment in Express to Spectra Energy Corp. for approximately $380 million (before tax). The Express pipeline system is a common carrier, crude oil pipeline system comprised of the Express Pipeline and the Platte Pipeline, collectively referred to in this report as the Express pipeline system. The approximate 1,700-mile integrated oil transportation pipeline system connects Canadian and United States producers to refineries located in the U.S. Rocky Mountain and Midwest regions. Based on the structure of our investment with our Express-Platte partners, we receive approximately $15 million of cash flow on an annual basis from this investment, which is primarily debenture interest. We will redeploy the proceeds from this sale into various growth projects to further benefit our unitholders. The transaction is subject to customary consents and regulatory approvals and is expected to close in the second quarter of 2013. On this date, Spectra also announced that it will acquire the remaining ownership interests in Express, and following its acquisitions, will fully own the Express pipeline system.

Financings

- For information about our 2012 debt offerings and retirements, see Note 8 "Debt—Changes in Debt" to our consolidated financial statements included elsewhere in this report. For information about our 2012 equity offerings, see Note 10 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

2013 Outlook

- As previously announced, we anticipate that for the year 2013, (i) we will declare cash distributions of $5.28 per unit, a 6% increase over our cash distributions of $4.98 per unit for 2012; (ii) our business segments will generate approximately $5.4 billion in earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments and our proportionate share of all non-cash depreciation, depletion and amortization expenses of certain joint ventures accounted for under the equity-method of accounting; (iii) we will distribute over $2.0 billion to our limited partners; (iv) we will produce excess cash flow of more than $30 million above our cash distribution target of $5.28 per unit; and (v) we will invest approximately $2.9 billion for our capital expansion program (including small acquisitions and contributions to joint ventures, but excluding acquisitions from KMI). Our anticipated 2013 expansion investment will help drive earnings and cash flow growth in 2013 and beyond, and we estimate that approximately $625 million of the equity required for our 2013 investment program will be funded by cash retained as a function of distributions to KMR being paid in additional units rather than in cash.

  Our expectations assume an average West Texas Intermediate (WTI) crude oil price of approximately $91.68 per barrel in 2013. Although the overwhelming majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO_2 business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. We hedge the majority of our crude oil production, but do have exposure to unhedged volumes, the majority of which are natural gas liquids volumes. For 2013, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment's cash flows by approximately $6 million (or approximately 0.1% of our combined business segments' anticipated earnings before depreciation, depletion and amortization expenses).

(b) Financial Information about Segments

For financial information on our five reportable business segments, see Note 15 "Reportable Segments" to our consolidated financial statements included elsewhere in this report.

(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 unitholders.

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

We regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, 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 our five operating limited partnerships and their subsidiaries and are grouped into five reportable business segments. These segments are as follows:

- Products Pipelines-which consists of approximately 8,600 miles of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus approximately 62 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the United States;

- Natural Gas Pipelines-which consists of approximately 33,000 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;

- CO_2- which produces, markets and transports, through approximately 1,500 miles of pipelines, carbon dioxide to oil fields that use carbon dioxide to increase production of oil; owns interests in and/or operates seven oil fields in West Texas; and owns and operates a 450-mile crude oil pipeline system in West Texas;

- Terminals-which consists of approximately 113 owned or operated liquids and bulk terminal facilities and approximately 35 rail transloading and materials handling facilities located throughout the United States 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 United States and Canada; and

- Kinder Morgan Canada-which transports crude oil and refined petroleum products through over 2,500 miles of pipelines from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States; plus five associated product terminal facilities.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products and natural gas liquids pipelines and associated terminals, Southeast terminals, and our transmix processing facilities.

West Coast Products Pipelines

Our West Coast Products Pipelines include our SFPP, L.P. operations (often referred to in this report as our Pacific operations), our Calnev pipeline operations, and our West Coast Terminals operations. The assets include interstate common carrier pipelines rate-regulated by the FERC, intrastate pipelines in the state of California rate-regulated by the California Public Utilities Commission, and certain non rate-regulated operations and terminal facilities.

Our 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 United States, including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. In 2012, our Pacific operations' mainline pipeline system transported approximately 1,056,600 barrels per day of refined products, with the product mix being approximately 60% gasoline, 23% diesel fuel, and 17% jet fuel.

Our Calnev pipeline system consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from our facilities at Colton, California to Las Vegas, Nevada. The pipeline serves the Mojave Desert 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 also includes approximately 55 miles of pipeline serving Edwards Air Force Base in California. In 2012, our Calnev pipeline system transported approximately 108,300 barrels per day of refined products, with the product mix being approximately 40% gasoline, 30% diesel fuel, and 30% jet fuel.

Our West Coast Products Pipelines operations include 15 truck-loading terminals (13 on our Pacific operations and two on Calnev) with an aggregate usable tankage capacity of approximately 15.3 million barrels. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

Our West Coast Terminals are fee-based terminals located in the Seattle, Portland, San Francisco and Los Angeles areas along the west coast of the United States with a combined total capacity of approximately 9.9 million barrels of storage for both petroleum products and chemicals. Our West Coast Products Pipelines and associated West Coast Terminals together handled 17.4 million barrels of ethanol in 2012.

Combined, our West Coast Products Pipelines operations' pipelines transport approximately 1.4 million barrels per day of refined petroleum products, providing pipeline service to approximately 28 customer-owned terminals, 11 commercial airports and 15 military bases. The pipeline systems serve approximately 61 shippers in the refined petroleum products market, the largest customers being major petroleum companies, independent refiners, and the United States military. The majority of refined products supplied to our West Coast Product Pipelines come from the major refining centers around Los Angeles, San Francisco, West Texas and Puget Sound, as well as from waterborne terminals and connecting pipelines located near these refining centers.

Plantation Pipe Line Company

We own approximately 51% of Plantation Pipe Line Company, the sole owner of the approximately 3,100-mile refined petroleum products Plantation pipeline system serving the southeastern United States. We operate 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 2012, Plantation delivered approximately 512,400 barrels per day of refined petroleum products, with the product mix being approximately 68% gasoline, 19% diesel fuel, and 13% 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 30 companies to terminals throughout the southeastern United States. Plantation's principal customers are Gulf Coast refining and marketing companies, and fuel wholesalers.

Central Florida Pipeline

Our 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. Our Central Florida pipeline operations also include two separate liquids terminals located in Tampa and Taft, Florida, which we own and operate.

In addition to being connected to our 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 our 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 2012, the pipeline system transported approximately 92,600 barrels per day of refined products, with the product mix being approximately 70% gasoline and ethanol, 10% diesel fuel, and 20% jet fuel.

Our Tampa terminal contains approximately 1.6 million barrels 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. Our Taft terminal contains approximately 0.8 million barrels of storage capacity, for gasoline, ethanol and diesel fuel for further movement into trucks.

Cochin Pipeline System

Our 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 70,000 barrels per day. It includes 31 pump stations spaced at 60 mile intervals and five United States 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 United States and can transport ethane, propane, butane and natural gas liquids to the midwestern United States and eastern Canadian petrochemical and fuel markets. In 2012, the system transported approximately 30,000 barrels per day of propane, and 7,000 barrels per day of ethane-propane mix. In 2014, we expect to complete the expansion and reversal of the Cochin pipeline system to transport 95,000 barrels per day of condensate from a new receipt terminal in Kankakee County, Illinois to third party storage in Fort Saskatchewan, Alberta.

Cypress Pipeline

We own 50% of Cypress Interstate Pipeline LLC, the sole owner of the Cypress pipeline system. We operate the system pursuant to a long-term agreement. The Cypress pipeline is an interstate common carrier natural gas liquids 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 natural gas liquids gathering, transportation, fractionation and storage in the United States. The Cypress pipeline system has a current capacity of approximately 55,000 barrels per day for natural gas liquids. In 2012, the system transported approximately 49,600 barrels per day.

Southeast Terminals

Our Southeast terminal operations consist of 28 high-quality, liquid petroleum products terminals located along the Plantation/Colonial pipeline corridor in the Southeastern United States. The marketing activities of our Southeast terminal operations are focused on the Southeastern United States 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, our Southeast terminals have a total storage capacity of approximately 9.1 million barrels. In 2012, these terminals transferred approximately 383,300 barrels of refined products per day and together handled 12.1 million barrels of ethanol.

Transmix Operations

Our 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. We process and separate 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; Wood River, Illinois; and Greensboro, North Carolina. Combined, our transmix facilities handled approximately 9.2 million barrels in 2012.

Kinder Morgan Crude and Condensate Pipeline

Our 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 24/30-inch pipeline currently originates in Dewitt County, Texas, and extends 175 miles to third party storage. The pipeline operates on a batch basis and has a capacity of 300,000 barrels per day. Pipeline operations began in the fourth quarter of 2012. Deliveries for the year totaled 1,416,000 barrels.

Competition

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

Natural Gas Pipelines

Our Natural Gas Pipelines segment contains both interstate and intrastate pipelines, which are FERC regulated and non-FERC regulated natural gas assets, respectively. Our non-FERC regulated natural gas assets are included in the KM Midstream

Group. Its primary businesses consist of natural gas sales, transportation, storage, gathering, processing and treating. Within this segment, we own approximately 33,000 miles of natural gas pipelines and associated storage and supply lines. Our transportation network provides access to the major gas supply areas in the western United States, Texas, the Midwest and Northeast, as well as major consumer markets.

KM Midstream Group

Texas Intrastate Natural Gas Pipeline Group

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

The two largest systems in the group are our Kinder Morgan Texas Pipeline and our 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 5,800 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 5.5 billion cubic feet per day of natural gas and approximately 130 billion cubic feet of on-system natural gas storage capacity, including approximately 11 billion cubic feet contracted from third parties five of which expires in March of 2013. In addition, the combined system (i) has facilities to both treat approximately 180 million cubic feet per day of natural gas for carbon dioxide and hydrogen sulfide removal, and to process approximately 85 million cubic feet per day of natural gas for liquids extraction; and (ii) holds contractual rights to process natural gas at certain third party facilities.

Our Mier-Monterrey Pipeline consists of a 95-mile natural gas pipeline that stretches from the international border between the United States and Mexico in Starr County, Texas, to Monterrey, Mexico and can transport up to 425 million cubic feet per day. The pipeline connects to the Pemex natural gas transportation system and serves a 1,000-megawatt power plant complex. We have entered into a long-term contract (expiring in 2018) with Pemex, which has subscribed for substantially all of the pipeline's capacity.

Our Kinder Morgan North Texas Pipeline consists of an 82-mile pipeline that transports natural gas from an interconnect with the facilities of Natural Gas Pipeline Company of America LLC (a 20%-owned equity investee of KMI and referred to in this report as NGPL) 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 located near Paris, Texas. It has the capacity to transport 325 million cubic feet per day 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.

Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in our 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 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, our Texas intrastate natural gas pipeline system primarily serves the Texas Gulf Coast by selling, transporting, processing and treating natural gas from multiple onshore and offshore 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. In 2012, the four natural gas pipeline systems in our Texas intrastate group provided an average of approximately 2.69 billion cubic feet per day of natural gas transport services. The Texas intrastate group also sold approximately 879.1 billion cubic feet of natural gas in 2012.

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, we purchase natural gas directly from producers with reserves connected to our intrastate natural gas system in South Texas, East Texas, West Texas, and along the Texas Gulf Coast. In addition, we also purchase gas at interconnects with third-party interstate and intrastate pipelines. While our 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. Our intrastate system has access to both onshore and offshore sources of supply, and is interconnected with both liquefied natural gas import terminals located on the Texas Gulf Coast. Our 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.

Table of Contents

Our subsidiary, Kinder Morgan Treating, L.P., owns and operates (or leases to producers for operation) treating plants that remove impurities (such as carbon dioxide 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, acquired on November 30, 2011, designs, constructs, and sells custom and stock natural gas treating plants and condensate stabilizers. Our rental fleet of treating assets includes approximately 212 natural gas amine-treating plants, approximately 55 hydrocarbon dew point control plants, and more than 178 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 Field Services LLC gathers and treats natural gas in the Haynesville shale gas formation located in northwest Louisiana. Its assets currently consist of approximately 479 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. The system is designed to have approximately 2.0 billion cubic feet per day of throughput capacity. The 2012 average annual throughput was approximately 1.0 billion cubic feet per day of natural gas, however, volumes on the system are declining due to reduced drilling activities.

KinderHawk owns life of lease dedications to gather and treat substantially all of Petrohawk Energy Corporation's (a subsidiary of BHP Billiton) operated Haynesville and Bossier shale gas production in northwest Louisiana 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.

EagleHawk Field Services LLC.

EagleHawk Field Services LLC provides natural gas and condensate gathering, treating, condensate stabilization and transportation services in the Eagle Ford shale formation in South Texas. We own a 25% equity ownership in EagleHawk Field Services LLC. Petrohawk Energy Corporation, a subsidiary of BHP Billiton, operates EagleHawk Field Services LLC and owns the remaining 75% ownership interest. EagleHawk owns two midstream gathering systems in and around Petrohawk's Hawkville and Black Hawk areas of the Eagle Ford shale formation and combined, its assets consist of more than 388 miles of gas gathering pipelines and approximately 266 miles of condensate lines. EagleHawk has a life of lease dedication of certain of Petrohawk's Eagle Ford reserves, and to a limited extent, contracts with other Eagle Ford producers to provide natural gas and condensate gathering, treating, condensate stabilization and transportation services.

Eagle Ford Gathering LLC

We own a 50% equity interest in Eagle Ford Gathering LLC, a joint venture that provides natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford shale gas formation in South Texas. It is owned 50% by us and 50% by Copano. Copano also serves as operator and managing member. Combined, the Eagle Ford Gathering system has approximately 180 miles of pipelines with capacity to gather and process over 700 million cubic feet of natural gas per day. The joint venture has executed long-term firm service agreements with multiple producers for the vast majority of its processing capacity, and has also executed interruptible service agreements with multiple producers under which natural gas can flow on a "as capacity is available" basis.

Red Cedar Gathering Company

We own a 49% equity interest in Red Cedar Gathering Company, a joint venture organized in August 1994 and referred to in this report as Red Cedar. 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 carbon dioxide treating plants. Throughput of the Red Cedar gathering system is approximately 600 million cubic feet per day of natural gas and the treating capacity is approximately 800 million cubic feet per day.

El Paso Midstream Investment Company

We acquired our 50% equity interest in EPMIC on June 1, 2012 from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. The remaining 50% interest in EPMIC is owned by KMI. EPMIC owns the Altamont natural gas

Table of Contents

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 1,200 miles of pipeline infrastructure, over 450 well connections with producers, a natural gas processing plant with a design capacity of 60 million cubic feet per day which is being expanded to 80 million cubic feet per day, and a natural gas liquids fractionator with a design capacity of 5,600 barrels per day. The Camino Real gathering system has the capacity to gather 150 million cubic feet per day of natural gas and 110,000 barrels per day of crude oil.

Endeavor Gathering LLC

We own a 40% equity interest in Endeavor Gathering LLC, which provides natural gas gathering service to GMX Resources 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. The natural gas gathering system has takeaway capacity of approximately 115 million cubic feet per day.

Pecos Valley Producer Services LLC

We own a 50% equity interest in Pecos Valley Producer Services LLC, a joint venture with Prism Midstream formed to develop natural gas gathering, processing and related opportunities in and around Reeves County, Texas. The joint venture's current activities include moving crude oil and natural gas liquids through a commodity rail terminal in Pecos, Texas that began operations on May 1, 2012. The terminal serves the growing oil and natural gas industries in the Permian Basin and offers a variety of services to producers including crude oil hauling, storage, transloading and marketing. The facility is operated by a subsidiary of Watco Companies, LLC, the largest privately held shortline railroad company in the United States. We own a preferred equity position in Watco.

Tennessee Gas Pipeline Company, L.L.C.

Our subsidiary, TGP, owns the approximate 13,900-mile Tennessee Gas natural gas pipeline system. We acquired TGP from KMI in the August 2012 drop-down transaction. The system has a design capacity of approximately 8.0 billion cubic feet per day for natural gas, and during 2012, the average throughput was 7.2 billion cubic feet per day. 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.

Our 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 across the Canadian border; and (iv) the previously discussed Eagle Ford formation, located in South Texas. The TGP system also includes approximately 93 billion cubic feet of underground working natural gas storage capacity through partially owned facilities or long-term contracts. Of this total storage capacity, 29 billion cubic feet is contracted from Bear Creek Storage Company, L.L.C. (Bear Creek) located in Bienville Parish, Louisiana. Bear Creek is a joint venture equally owned by us and El Paso Pipeline Partners, L.P., or EPB, an affiliate of KMI. The facility has 58 billion cubic feet of working natural gas storage capacity that is committed equally to EPB and us.

Our 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 our ability to extend our 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 we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariff, we frequently enter into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive. As of December 31, 2012, our TGP pipeline system serviced approximately 439 firm and interruptible customers, and was a party to approximately 458 firm transportation contracts.

Western Interstate Natural Gas Pipeline Group

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

El Paso Natural Gas Pipeline Company, L.L.C.

Our 50%-owned equity investee, EPNG, is the sole owner of (i) the 10,200-mile El Paso Natural Gas pipeline system; and (ii) Mojave Pipeline Company, LLC, the sole owner of the approximate 500-mile Mojave Pipeline system. We acquired our 50% equity interest in EPNG in the August 2012 drop-down transaction. KMI owns the remaining ownership interest in both pipeline systems. 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 billion cubic feet per day for natural gas (reflecting winter-sustainable west-flow capacity of 4.85 billion cubic feet per day and approximately 800 million cubic feet per day of of east-end delivery capacity). As of December 31, 2012, the EPNG pipeline system serviced approximately 80 firm and interruptible customers, and was a party to approximately 180 firm transportation contracts that had a weighted average remaining contract term of approximately 2.5 years.

The Mojave system connects with other pipeline systems including (i) the EPNG system near Cadiz, California; (ii) the EPNG and Transwestern Pipeline Company, LLC (Transwestern) 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. It has a design capacity of 400 million cubic feet per day (reflecting east to west flow activity). As of December 31, 2012, the Mojave pipeline system serviced approximately six firm and interruptible customers of which two held firm transportation contracts that had a weighted average remaining contract term of approximately three years.

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.

TransColorado Gas Transmission Company LLC

Our subsidiary, TransColorado Gas Transmission Company LLC, referred to in this report as TransColorado, owns a 300-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. Our 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 billion cubic feet per day of natural gas. In 2012, our TransColorado pipeline system transported an average of approximately 400 million cubic feet per day of natural gas.

Our 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

Our Central interstate natural gas pipeline group, which operates primarily in the Mid-Continent region of the United States, consists of the following three natural gas pipeline systems (i) Kinder Morgan Louisiana Pipeline; (ii) our 50% ownership interest in the Midcontinent Express Pipeline; and (iii) our 50% ownership interest in the Fayetteville Express Pipeline.

Kinder Morgan Louisiana Pipeline

Our subsidiary, Kinder Morgan Louisiana Pipeline LLC owns the Kinder Morgan Louisiana natural gas pipeline system. The pipeline system provides approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas 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 is a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas 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 2.3 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 a one-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that extends from the Sabine Pass terminal and connects to NGPL's natural gas pipeline.

Midcontinent Express Pipeline LLC

We own a 50% interest in Midcontinent Express Pipeline LLC, the sole owner of the approximate 500-mile Midcontinent Express natural gas pipeline system. We also operate the Midcontinent Express pipeline system. 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 United States' eastern markets.

The pipeline system is comprised of approximately 30-miles of 30-inch diameter pipe, 275-miles of 42-inch diameter pipe and 197-miles of 36-inch diameter pipe. Midcontinent Express also has four compressor stations and one booster station totaling approximately 144,500 horsepower. It has two rate zones: (i) Zone 1 (which has a capacity of 1.8 billion cubic feet per day) beginning at Bennington and extending to an interconnect with Columbia Gulf Transmission near Delhi, in Madison Parish Louisiana; and (ii) Zone 2 (which has a capacity of 1.2 billion cubic feet per day) 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 2014 and 2020. The majority of volume is contracted to producers moving supply from the Barnett shale and Oklahoma supply basins.

Fayetteville Express Pipeline LLC

We own a 50% interest in Fayetteville Express Pipeline LLC, the sole owner of the Fayetteville Express natural gas pipeline system. The 187-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. On January 1, 2011, Fayetteville Express Pipeline LLC began firm contract pipeline transportation service to its customers. Capacity on the Fayetteville Express system is over 90% contracted under long-term firm service agreements.

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 attachments 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

Our CO_2 segment consists of our subsidiary Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates, collectively referred to in this report as KMCO_2. Our CO_2 business segment produces, transports, and markets carbon dioxide for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. KMCO_2's carbon dioxide pipelines and related assets allow it to market a complete package of carbon dioxide 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 21% net profits interest in the H.T. Boyd unit; (iv) an approximate 99% working interest in the Katz Strawn unit; and (v) 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 United States using carbon dioxide 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 carbon dioxide project initiated by the previous owners and increased production and ultimate oil recovery over the last several years. In 2012, the average purchased carbon dioxide injection rate at SACROC was 118 million cubic feet per day. The average oil production rate for 2012 was approximately 29,000 barrels of oil per day (24,100 net barrels to KMCO_2 per day).

The Yates unit is also one of the largest oil fields ever discovered in the United States. 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 carbon dioxide injection to ensure a relatively steady production profile over the next several years. In 2012, the average purchased carbon dioxide injection rate at the Yates unit was 98 million cubic feet per day, and during 2012, the Yates unit produced approximately 20,800 barrels of oil per day (9,300 net barrels to KMCO_2 per day).

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 2012, the Katz Strawn unit produced approximately 1,700 barrels of oil per day (1,400 net barrels to KMCO_2 per day). In 2012, the average purchased carbon dioxide injection rate at the Katz Strawn unit was 62 million cubic feet per day.

During 2012, KMCO_2 sold its approximate 65% gross working interest in the Claytonville oil field unit located in the Permian Basin area of West Texas to the Scout Energy Group. The Claytonville unit is located nearly 30 miles east of the SACROC unit, in Fisher County, Texas.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we owned interests as of December 31, 2012. The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. When used with respect to acres or wells, "gross" refers to the total acres or wells in which we have a working interest, and "net" refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells (a)		Service Wells (b)		Drilling Wells (c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,089	1,311	924	718	3	3
Natural Gas	5	2	—	—	—	—
Total Wells	2,094	1,313	924	718	3	3

(a) Includes active wells and wells temporarily shut-in. As of December 31, 2012, we did not operate any productive wells with multiple completions.

(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of salt water into an underground formation; and an injection well is a well drilled in a known oil field in order to inject liquids that enhance recovery.

(c) Consists of development wells in the process of being drilled as of December 31, 2012. A development well is a well drilled in an already discovered oil field.

The following table reflects our net productive and dry wells that were completed in each of the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Productive			
Development	59	85	70
Exploratory	—	—	—
Dry			
Development	—	—	—
Exploratory	—	—	—
Total Wells	59	85	70

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

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2012:

	Gross	Net
Developed Acres	68,945	65,811
Undeveloped Acres	14,557	13,971
Total	83,502	79,782

Note: As of December 31, 2012, we have no material amount of acreage expiring in the next three years.

See “Supplemental Information on Oil and Gas Activities (Unaudited)” included elsewhere in this report for additional information with respect to operating statistics and supplemental information on our 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 carbon dioxide projects, specifically the Sharon Ridge and

Table of Contents

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 natural gas liquids at the Snyder gasoline plant during 2012 averaged approximately 18,900 gross barrels per day (9,300 net barrels to $KMCO_2$ per day excluding the value associated to $KMCO_2$'s 28% net profits interest).

Sales and Transportation Activities

Carbon Dioxide

$KMCO_2$ owns approximately 45% of, and operates, the McElmo Dome unit in Colorado, which contains more than 6.6 trillion cubic feet of recoverable carbon dioxide. It also owns approximately 87% of, and operates, the Doe Canyon Deep unit in Colorado, which contains approximately 871 billion cubic feet of recoverable carbon dioxide. For both units combined, compression capacity exceeds 1.4 billion cubic feet per day of carbon dioxide and during 2012, the two units produced approximately 1.21 billion cubic feet per day of carbon dioxide.

$KMCO_2$ also owns approximately 11% of the Bravo Dome unit in New Mexico. The Bravo Dome unit contains approximately 801 billion cubic feet of recoverable carbon dioxide and produced approximately 300 million cubic feet of carbon dioxide per day in 2012.

Our principal market for carbon dioxide is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain strong for the next several years.

Carbon Dioxide Pipelines

As a result of our 50% ownership interest in Cortez Pipeline Company, we own a 50% equity interest in and operate the approximate 500-mile Cortez pipeline. The pipeline carries carbon dioxide from the McElmo Dome and Doe Canyon source fields near Cortez, Colorado to the Denver City, Texas hub. The Cortez pipeline transports approximately 1.2 billion cubic feet of carbon dioxide 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 an ultimate throughput capacity of 700 million cubic feet per day. At its origination point in Denver City, the Central Basin pipeline interconnects with all three major carbon dioxide 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. The tariffs charged by the Central Basin pipeline are not regulated.

$KMCO_2$'s Centerline carbon dioxide 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 million cubic feet per day. The tariffs charged by the Centerline pipeline are not regulated.

$KMCO_2$'s Eastern Shelf carbon dioxide 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. Two 500 horsepower pumps were placed in service in 2012, increasing the capacity of the pipeline from 70 million to 100 million cubic feet per day. The Eastern Shelf Pipeline system is currently flowing 64 million cubic feet per day. The tariffs charged on the Eastern Shelf pipeline are not regulated.

$KMCO_2$ also owns a 13% undivided interest in the 218-mile, Bravo pipeline, which delivers carbon dioxide from the Bravo Dome source field in northeast New Mexico to the Denver City hub and has a capacity of more than 350 million cubic feet per day. 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 million cubic feet per day 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 million cubic feet per day 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 our carbon dioxide pipelines is to customers, including ourselves, using carbon dioxide 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.

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. to transport crude oil into Western's 120,000 barrel per day 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 130,000 barrels of crude oil per day with the use of drag reduction agent (DRA), and it transported approximately 119,000 barrels of oil per day in 2012. The Kinder Morgan Wink Pipeline is regulated by both the FERC and the Texas Railroad Commission.

Competition

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

Terminals

Our Terminals segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately 113 owned or operated liquids and bulk terminal facilities and approximately 35 rail transloading and materials handling facilities. Our terminals are located throughout the United States and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers helps keep customers at our terminals and provides us opportunities for expansion. We often classify our terminal operations based on their handling of either liquids or bulk material products.

Liquids Terminals

Our liquids terminals operations primarily store refined petroleum products, petrochemicals, ethanol, industrial chemicals and vegetable oil products in aboveground storage tanks and transfer products to and from pipelines, vessels, tank trucks, tank barges, and tank railcars. Combined, our approximately 27 liquids terminals facilities possess liquids storage capacity of approximately 60.1 million barrels, and in 2012, these terminals handled approximately 630 million barrels of liquids products, including petroleum products, ethanol and chemicals.

Bulk Terminals

Our bulk terminal operations primarily involve dry-bulk material handling services. We also provide 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. We own or operate approximately 83 dry-bulk terminals in the United States and Canada, and combined, our dry-bulk and material transloading facilities (described below) handled approximately 97 million tons of coal, petroleum coke, fertilizers, steel, ores and other dry-bulk materials in 2012.

Materials Services (rail transloading)

Our materials services operations include rail or truck transloading shipments from one medium of transportation to another conducted at approximately 35 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. We also design and build transloading facilities, perform inventory management services, and provide value-added services such as blending, heating and sparging.

As of March 31, 2013 TRANSFLO, a wholly owned subsidiary of CSX has elected to terminate their contract with our 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 United States. KMMS performed transloading services at the 25 terminals, which included rail-to-truck and truck-to-rail transloading of bulk and liquid products.

Competition

We are one of the largest independent operators of liquids terminals in the United States, based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical and pipeline companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminal services. In some locations, our competitors are smaller, independent operators with lower cost structures. Our rail transloading (material services) operations compete with a variety of single- or multi-site transload, warehouse and terminal operators across the United States. Our ethanol rail transload operations compete with a variety of ethanol handling terminal sites across the United States, many offering waterborne service, truck loading, and unit train capability serviced by Class 1 rail carriers.

Kinder Morgan Canada

Our Kinder Morgan Canada business segment includes our Trans Mountain pipeline system, our ownership of a one-third interest in the Express pipeline system, and our 25-mile Jet Fuel pipeline system. The weighted average remaining life of the shipping contracts on these pipeline systems was approximately two years as of December 31, 2012.

Trans Mountain Pipeline System

Our 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. Trans Mountain's pipeline is 715 miles in length. We also own a connecting pipeline that delivers crude oil to refineries in the state of Washington. The capacity of the line at Edmonton ranges from 300,000 barrels per day when heavy crude represents 20% of the total throughput (which is a historically normal heavy crude percentage), to 400,000 barrels per day with no heavy crude. Trans Mountain is the sole pipeline carrying crude oil and refined petroleum products from Alberta to the west coast. As the recently announced expansion proposal demonstrates, we believe these facilities provide us the opportunity to execute on capacity expansions to the west coast as the market for offshore exports continues to develop.

In 2012, Trans Mountain delivered an average of 291,000 barrels per day. The crude oil and refined petroleum products transported through Trans Mountain's pipeline system originates in Alberta and British Columbia. The refined and partially refined petroleum products transported to Kamloops, British Columbia and Vancouver originates from oil refineries located in Edmonton. Petroleum products delivered through Trans Mountain's pipeline system are used in markets in British Columbia, Washington State and elsewhere offshore.

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 our 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 135,000 barrels per day when heavy crude represents approximately 25% 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.

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. Trans Mountain anticipates National Energy Board approval in the second quarter of 2013.

Express System

We own a one-third ownership interest in the Express pipeline system. We operate the Express pipeline system and account for our one-third investment under the equity method of accounting. The Express pipeline system is a batch-mode, common-carrier, crude oil pipeline system comprised of the Express Pipeline and the Platte Pipeline, collectively referred to in this report as the Express pipeline system. The approximate 1,700-mile integrated oil transportation pipeline connects Canadian and United States producers to refineries located in the U.S. Rocky Mountain and Midwest regions.

The Express Pipeline is a 780-mile, 24-inch diameter pipeline that begins at the crude oil pipeline terminal at Hardisty, Alberta and terminates at the Casper, Wyoming facilities of the Platte Pipeline. The Express Pipeline has a design capacity of 280,000 barrels per day. Receipts at Hardisty averaged 191,700 barrels per day in 2012.

The Platte Pipeline is a 926-mile, 20-inch diameter pipeline that runs from the crude oil pipeline terminal at Casper, Wyoming to refineries and interconnecting pipelines in the Wood River, Illinois area. The Platte Pipeline has a current capacity of approximately 150,000 barrels per day downstream of Casper, Wyoming and approximately 140,000 barrels per day downstream of Guernsey, Wyoming. Platte deliveries averaged 148,000 barrels per day in 2012.

On December 11, 2012, we announced that we had entered into a definitive agreement to sell our interest in the Express Pipeline system to Spectra. Such sale is expected to close in the second quarter of 2013.

Jet Fuel Pipeline System

We also own and operate the approximate 25-mile aviation fuel pipeline that serves the Vancouver International Airport, located in Vancouver, British Columbia, Canada. The turbine fuel pipeline is referred to in this report as our 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 15,000 barrels.

Competition

Trans Mountain and the Express pipeline system are each one of several pipeline alternatives for western Canadian crude oil and refined petroleum production, and each competes against other pipeline providers.

Major Customers

Our total operating revenues are derived from a wide customer base. For each of the years ended December 31, 2012, 2011 and 2010, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, our CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from our Natural Gas Pipelines and CO_2 business segments in 2012, 2011 and 2010 accounted for 29%, 42% and 46%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

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

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

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 16 to our consolidated financial statements included elsewhere in this report.

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 Canada's National Energy Board, referred to in this report as the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service.

Trans Mountain Pipeline. Our subsidiary Trans Mountain Pipeline, L.P. previously had a one-year toll settlement with shippers that expired on December 31, 2012. In February 2013, Trans Mountain Pipeline completed negotiations with the Canadian Association of Petroleum Producers for a new negotiated toll settlement for our Trans Mountain Pipeline to be effective for 2013. Trans Mountain anticipates approval from the NEB in the second quarter of 2013. The toll charged for the portion of Trans Mountain's pipeline system located in the United States falls under the jurisdiction of the FERC. See "-Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations."

Express Pipeline. The Canadian segment of the Express Pipeline is regulated by the NEB as a Group 2 pipeline, which results in rates and terms of service being regulated on a complaint basis only. Express committed contract rates are subject to a 2% inflation adjustment April 1 of each year. The U.S. segment of the Express Pipeline and the Platte Pipeline are regulated by the FERC. See "-Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations." Additionally, movements on the Platte Pipeline within the state of Wyoming are regulated by the Wyoming Public Service Commission, which regulates the tariffs and terms of service of public utilities that operate in the state of Wyoming. The Wyoming Public Service Commission standards applicable to rates are similar to those of the FERC and the NEB.

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.

California Public Utilities Commission Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the California Public Utilities Commission, referred to in this report as the CPUC, under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of our Pacific operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to our intrastate rates. Certain of our Pacific operations' pipeline rates have been, and continue to be, subject to complaints with the CPUC, as is more fully described in Note 16 to our consolidated financial statements included elsewhere in this report.

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) on September 30, 2002 that defines the general and directional conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit has a term of 30 years.

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 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to as 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 U.S. 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. PHMSA recently 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 Federal 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.

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 United States 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 U.S. generally accepted accounting principles, 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 probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency, referred to in this report as the U.S. 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 multiparty 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 $119 million as of December 31, 2012. Our reserve estimates range in value from approximately $119 million to approximately $170 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 to our consolidated financial statements included elsewhere in this report.

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 U.S. 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 Comprehensive Environmental Response, Compensation and Liability Act, also known as 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 U.S. 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 U.S. EPA adopted new regulations under the Clean Air Act that took effect in early 2011 and that establish requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. 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 state waters or waters of the United States. 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.

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 carbon dioxide, 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.

The EPA published in December 2009 its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment. Pursuant to this endangerment finding and other rulemakings and interpretations, EPA concluded that stationary sources would become subject to federal permitting requirements under the Clean Air Act in starting in 2011. In 2010, the EPA issued a final rule, known as the "Tailoring Rule," that defined regulatory emissions thresholds at which certain new and modified stationary sources would become subject to permitting and other requirements for greenhouse gas emissions under the Clean Air Act. Some of our facilities emit greenhouse gases in excess of the Tailoring Rule's thresholds and have been required to obtain, and must continue to comply with, a Title V Permit for greenhouse gas emissions. In 2011, the EPA implemented permitting for new and/or modified sources of greenhouse gas emissions through the existing PSD permitting program. The EPA has indicated in rulemakings that it may reduce the current Tailoring Rule regulatory thresholds for greenhouse gases, making additional sources subject to PSD permitting requirements, but has declined to do so at this time. Permitting requirements for greenhouse gas emissions may also trigger permitting requirements for emissions of other regulated air pollutants as well. Additional direct regulation of greenhouse gas emissions in our industry may be implemented under other Clean Air Act programs, including the New Source Performance Standards, or NSPS, program. The EPA has already proposed to regulate greenhouse gas emissions from certain electric generating units under the NSPS program. A final regulation is expected in 2013. While these proposed NSPS regulations for electric generating units would not directly apply to our operations, the EPA may propose a greenhouse gas NSPS for additional source categories.

In addition, in 2009 the EPA published a final rule requiring that specified large greenhouse gas emissions sources annually report the greenhouse gas emissions for the preceding year in the United States, beginning in 2011 for emissions occurring in 2010. In 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect in December 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. Some of our facilities are required to report under this rule, and operational and/or regulatory changes could require additional facilities to comply with greenhouse gas emissions reporting requirements.

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. Depending on the particular program, we could be required to purchase and surrender emission allowances.

Because our operations, including our compressor stations and processing plants, emit various types of greenhouse gases, primarily methane and carbon dioxide, such new legislation or regulation could increase our costs related to operating and maintaining our facilities. Depending on the particular law, regulation or program, we could be required to incur capital expenditures for installing new emission controls on our facilities, acquire and surrender allowances for our greenhouse gas emissions, pay taxes related to our 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 pipelines, such recovery of costs in all cases is uncertain and may depend on events beyond our 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 U.S. 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 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 the magnitude and direction of these impacts cannot now be predicted, greenhouse gas regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

EPA Regulation of Internal Combustion Engines

Internal combustion engines used in our operations are also subject to EPA regulation under the Clean Air Act. The EPA published new regulations on emissions of hazardous air pollutants from reciprocating internal combustion engines on August 20, 2010. On June 7, 2012, the EPA proposed amendments to these regulations which are expected to be finalized in the near future. The EPA also revised the New Source Performance Standards for stationary compression ignition and spark ignition internal combustion engines on June 28, 2011 and has proposed minor amendments, included in the June 7, 2012 proposed rule. Compliance with these new regulations may require significant capital expenditures for physical modifications and may require operational changes as well. We are not able to estimate such increased costs, however, as is the case with similarly situated entities in the industry, they could be significant for us.

Recent EPA Rules Regarding Oil and Natural Gas Air Emissions

In addition, on April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules were published in the Federal Register on August 16, 2012 and became effective on October 15, 2012. For new or reworked hydraulically fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or “green”) completions until 2015, when the rules require the use of green completions. The rules also establish specific new requirements, effective in 2012, for emissions from compressors, dehydrators, storage tanks, gas processing plants and certain other equipment. These rules may therefore require a number of modifications to our and our customers’ operations, including the installation of new equipment to control emissions. In October 2012, several challenges to EPA’s rules were filed by various parties, including environmental groups and industry associations. Depending on the outcome of such proceedings, the rules may be modified or rescinded or EPA may issue new rules, the costs of compliance with any modified or newly issued rules cannot be predicted.

Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources are appropriate, and, if so, to promulgate performance standards for methane emissions from the oil and gas sector, which was not addressed in the EPA rule that became effective on October 15, 2012. The notice of intent also requested EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules may also make it more difficult for us and our customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business.

Department of Homeland Security

In Section 550 of the Homeland Security Appropriations Act of 2007, the U.S. Congress gave the Department of Homeland Security, referred to in this report as the DHS, regulatory authority over security at certain high-risk chemical facilities. Pursuant to its congressional mandate, on April 9, 2007, the DHS 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

KMGP Services Company, Inc., KMI, Kinder Morgan Canada Inc. and another affiliate employ all persons necessary for the operation of our business. Generally, we reimburse these entities for the services of their employees. As of December 31, 2012, KMGP Services Company, Inc., KMI, Kinder Morgan Canada Inc. and other affiliated entities had, in the aggregate, 10,685 full-time employees. Approximately 818 full-time hourly personnel at certain terminals and pipelines are represented by labor unions under collective bargaining agreements that expire between 2013 and 2017. KMGP Services Company, Inc., KMI, Kinder Morgan Canada Inc. and other affiliated entities each consider relations with their employees to be good. For more information on our related party transactions, see Note 11 to our consolidated financial statements included elsewhere in this report.

Properties

We believe that we have generally 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 to our consolidated financial statements included elsewhere in this report.

(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 Securities and Exchange Commission (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 position, results of operations or cash flows. There are also risks associated with being an owner of common units in a partnership that are different than being an owner of common stock in a corporation. Investors in our common units should be aware that the realization of any of those risks could result in a decline in the trading price of our common units, and they might lose all or part of their investment.

Risks Related to Our Business

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 pipelines and storage facilities 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, 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 to our consolidated financial statements included elsewhere in this report, to the rates we charge on our 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 carbon dioxide 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.

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 compliance costs are pipeline integrity testing and the repairs. 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 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.

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 United States 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. 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 in restricted areas, 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 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 carbon dioxide, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. EPA began regulating the greenhouse gas emissions in 2011, requiring the reporting of greenhouse gas emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large greenhouse gas emission sources, fractionated natural gas liquids, and the production of naturally occurring carbon dioxide, like our McElmo Dome carbon dioxide 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 carbon dioxide, such regulation could increase our costs related to operating and maintaining our facilities and 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. We are not able at this time to estimate such increased costs; however, they 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 our revenues by decreasing the volumes of natural gas transported on our or our joint ventures' 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. Recently, 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 recontract 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.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. A variety of factors outside of our control, such as 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 we have the power of eminent domain for our pipelines, other than interstate natural gas pipelines, varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas or carbon dioxide—and the laws of the particular state. Our interstate natural gas pipelines have federal eminent domain authority. In either case, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

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

Table of Contents

In addition, due to our relationship with KMI, our credit ratings, and thus our ability to access the capital markets and the terms and pricing we receive therein, may be adversely affected by any impairment to KMI's financial condition or adverse changes in its credit ratings. Similarly, 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 debt instruments, as well as the market value of our common units.

Our acquisition strategy and expansion programs require access to new capital. Limitations on our access to capital would impair our ability to grow.

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

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

As of December 31, 2012, we had $15.9 billion of consolidated debt (excluding the value of interest rate swap agreements). 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 distributions 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 distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 8 to our consolidated financial statements included elsewhere in this report.

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

As of December 31, 2012, approximately $6.2 billion (39%) of our total $15.9 billion consolidated debt (excluding the value of interest rate swap agreements) 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 growth strategy may cause difficulties integrating and constructing new operations, and we may not be able to achieve the expected benefits from any future acquisitions or expansions.

Part of our business strategy includes acquiring additional businesses, some of which may occur in drop-down transactions from KMI, expanding existing assets and constructing new facilities. If we do not successfully integrate acquisitions, expansions or newly constructed facilities, we may not realize anticipated operating advantages and cost savings. The integration of acquired companies or new assets involves a number of risks, including (i) demands on management related to the increase in our size; (ii) the diversion of management's attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems; (iv) difficulties in the assimilation and retention of necessary employees; and (v) potential adverse effects on operating results.

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

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 our crude oil, natural gas and refined petroleum products 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 our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves and revenues of the oil and gas producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

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

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

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

The revenues, profitability and future growth of our CO_2 business segment and the carrying value of its oil, natural gas liquids and natural gas properties depend to a large degree on prevailing oil and gas prices. For 2013, we estimate that every $1 change in the average West Texas Intermediate crude oil price per barrel would impact our CO_2 segment's cash flows by approximately $6 million. Prices for oil, natural gas liquids and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil, natural gas liquids and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the United States; (ii) the condition of the United States 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, natural gas liquids or natural gas would result in a commensurate reduction in our revenues, income and cash flows from the production of oil, natural gas liquids, and natural gas and could have a material adverse effect on the carrying value of our proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our 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. For more information about our hedging activities, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Hedging Activities" and Note 13 to our consolidated financial statements included elsewhere in this report.

The recent 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 over-the-counter derivatives market and entities that participate in that market. While the CFTC's rule promulgated pursuant to the Dodd-Frank Act has been vacated by a U.S. District Court and is on appeal, the CFTC has taken the position that the act also requires the CFTC to institute broad new aggregate position limits for over-the-counter 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 new 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.

Our Kinder Morgan Canada 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 our Kinder Morgan Canada business segment, a portion of our consolidated assets, liabilities, revenues and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between United States 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 partners' capital 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 United States 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 natural gas liquids will have a negative impact on the results of our CO_2 business segment. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the United States 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.

Risks Related to Ownership of Our Common Units

The interests of KMI may differ from our interests and the interests of our unitholders.

KMI indirectly owns all of the common stock of our general partner and elects all of its directors. Our general partner owns all of KMR's voting shares and elects all of its directors. Furthermore, some of KMR's and our general partner's directors and officers are also directors and officers of KMI and its other subsidiaries, including EPB, and have fiduciary duties to manage the businesses of KMI and its other subsidiaries in a manner that may not be in the best interests of our unitholders. KMI has a number of interests that differ from the interests of our unitholders. As a result, there is a risk that important business decisions will not be made in the best interests of our unitholders.

Our partnership agreement and the KMR limited liability company agreement restrict or eliminate a number of the fiduciary duties that would otherwise be owed by our general partner and/or its delegate to our unitholders.

Modifications of state law standards of fiduciary duties may significantly limit the ability of our unitholders to successfully challenge the actions of our general partner in the event of a breach of fiduciary duties. These state law standards include the duties of care and loyalty. The duty of loyalty, in the absence of a provision in the limited partnership agreement to the contrary, would generally prohibit our general partner from taking any action or engaging in any transaction as to which it has a conflict of interest. Our limited partnership agreement contains provisions that prohibit limited partners from advancing claims that otherwise might raise issues as to compliance with fiduciary duties or applicable law. For example, that agreement provides that the general partner may take into account the interests of parties other than us in resolving conflicts of interest. It also provides that in the absence of bad faith by the general partner, the resolution of a conflict by the general partner will not be a breach of any duty. The provisions relating to the general partner apply equally to KMR as its delegate. It is not necessary for a limited partner to sign our limited partnership agreement in order for the limited partnership agreement to be enforceable against that person.

Common unitholders have limited voting rights and limited control.

Holders of common units have only limited voting rights on matters affecting us. Our general partner manages partnership activities. Under a delegation of control agreement, our general partner has delegated the management and control of our and our subsidiaries' business and affairs to KMR. Holders of common units have no right to elect the general partner or any of the directors of the general partner or KMR on an annual or other ongoing basis. If the general partner withdraws, however, its successor may be elected by the holders of a majority of the outstanding units of all classes (excluding common units and Class B units owned by the departing general partner and its affiliates and excluding the number of i-units corresponding to the number of any KMR shares owned by the departing general partner and its affiliates).

The limited partners may remove the general partner only if (i) the holders of at least 66 2/3% of the outstanding units of all classes, excluding common units and Class B units owned by the general partner and its affiliates and excluding the number of i-units corresponding to the number of any KMR shares owned by the general partner and its affiliates, vote to remove the general partner; (ii) a successor general partner is approved by the same vote; and (iii) we receive an opinion of counsel opining that the removal would not result in the loss of the limited liability of any limited partner or of the limited partner of an operating partnership, or cause us or an operating partnership to be taxed as a corporation or otherwise to be taxed as an entity for federal income tax purposes.

A person or group owning 20% or more of the common units and KMR shares on a combined basis cannot vote.

Any common units or KMR shares held by a person or group that owns 20% or more of the aggregate number of common units and KMR shares on a combined basis cannot be voted. This limitation does not apply to the general partner and its affiliates. This provision may (i) discourage a person or group from attempting to remove the general partner or otherwise change management; and (ii) reduce the price at which the common units will trade under certain circumstances. For example, a third party will probably not attempt to take over our management by making a tender offer for the common units at a price above their trading market price without removing the general partner and substituting an affiliate of its own.

The general partner's liability to us and our unitholders may be limited.

Our partnership agreement contains language limiting the liability of the general partner to us or the holders of common units. For example, our partnership agreement provides that (i) the general partner does not breach any duty to us or the holders of common units by borrowing funds or approving any borrowing (the general partner is protected even if the purpose or effect of the borrowing is to increase incentive distributions to the general partner); (ii) the general partner does not breach

Table of Contents

any duty to us or the holders of common units by taking any actions consistent with the standards of reasonable discretion outlined in the definitions of available cash and cash from operations contained in our partnership agreement; and (iii) the general partner does not breach any standard of care or duty by resolving conflicts of interest unless the general partner acts in bad faith.

Unitholders may have liability to repay distributions.

Unitholders will not be liable for assessments in addition to their initial capital investment in the common units. Under certain circumstances, however, holders of common units may have to repay us amounts wrongfully returned or distributed to them. Under Delaware law, we may not make a distribution to unitholders if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of such a distribution, a limited partner who receives the distribution and knew at the time of the distribution that the distribution violated Delaware law will be liable to the limited partnership for the distribution amount. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to the assignee at the time the assignee became a limited partner if the liabilities could not be determined from the partnership agreement.

Unitholders may be liable if we have not complied with state partnership law.

We conduct our business in a number of states. In some of those states the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. The unitholders might be held liable for the partnership's obligations as if they were a general partner if (i) a court or government agency determined that we were conducting business in the state but had not complied with the state's partnership statute; or (ii) unitholders' rights to act together to remove or replace the general partner or take other actions under our partnership agreement constitute "control" of our business.

The general partner may buy out minority unitholders if it owns 80% of the aggregate number of common units and KMR shares.

If at any time the general partner and its affiliates own 80% or more of the aggregate number of issued and outstanding common units and KMR shares, the general partner will have the right to purchase all, and only all, of the remaining common units, but only if KMI elects to purchase all, and only all, of the outstanding KMR shares that are not held by KMI and its affiliates pursuant to the purchase provisions that are a part of the limited liability company agreement of KMR. Because of this right, a unitholder could have to sell its common units at a time or price that may be undesirable. The purchase price for such a purchase will be the greatest of (i) the 20-day average closing price for the common units or the KMR shares as of the date five days prior to the date the notice of purchase is mailed; or (ii) the highest purchase price paid by the general partner or its affiliates to acquire common units or KMR shares during the prior 90 days. The general partner can assign this right to its affiliates or to us.

We may sell additional limited partner interests, diluting existing interests of unitholders.

Our partnership agreement allows the general partner to cause us to issue additional common units and other equity securities. When we issue additional equity securities, including additional i-units to KMR when it issues additional shares, unitholders' proportionate partnership interest in us will decrease. Such an issuance could negatively affect the amount of cash distributed to unitholders and the market price of common units. Issuance of additional common units will also diminish the relative voting strength of the previously outstanding common units. Our partnership agreement does not limit the total number of common units or other equity securities we may issue.

The general partner can protect itself against dilution.

Whenever we issue equity securities to any person other than the general partner and its affiliates, the general partner has the right to purchase additional limited partnership interests on the same terms. This allows the general partner to maintain its proportionate partnership interest in us. No other unitholder has a similar right. Therefore, only the general partner may protect itself against dilution caused by issuance of additional equity securities.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for U.S.

federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any tax other matter affecting us.

Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for U.S. federal income tax purposes. Although we do not believe, based on our current operations, that we are or will be so treated, the IRS could disagree with the positions we take or a change in our business (or a change in current law) could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions or credits would flow through to our unitholders. Because tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation for U.S. federal income tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units 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. For example, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. If any additional state income taxes were imposed upon us as an entity, our cash available for distribution would be reduced. 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 an investment in our units.

If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely affected and the costs of such contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS, and the outcome of any IRS contest, may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution.

Our common unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our common unitholders are treated as partners to whom we allocate taxable income that could be different in amount than the cash we distribute, they are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. Common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a common unitholder sells its common units, the common unitholder will recognize a gain or loss equal to the difference between the amount realized and that common unitholder's adjusted tax basis in those common units. Because distributions in excess of a common unitholder's allocable share of our net taxable income result in a decrease of that unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units sold will, in effect, become taxable income allocated to that unitholder if the unitholder sells such common units at a price greater than that unitholder's tax basis in those common units, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a common unitholder's share of our nonrecourse liabilities, a unitholder that sells its common units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Any tax-exempt entity or non-U.S. person should consult its tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we treat each purchaser of our common units as having the same tax benefits with regard to the actual common units purchased and we adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our common unitholders.

Our valuation methodologies may result in a shift of income, gain, loss and deduction between our general partner and the common unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our common unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our common unitholders and our general partner. It also could affect the amount of gain from our common unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our common unitholders' or our general partner's tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in a termination of our partnership for U.S. federal income tax purposes.

We will be considered to have technically terminated as a partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief from the IRS was not available, as described below) for one fiscal year. The termination could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a calender year, the closing of our taxable year may also result in more than twelve months of our taxable income being includable in the common unitholder's taxable income for the year of termination. Under current law, a technical termination would not affect our classification as a partnership for U.S. federal income tax purposes, but instead, after our termination we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby a publicly traded partnership that technically terminated may request publicly traded partnership technical termination relief which, if granted by the IRS, among other things would permit the partnership to provide only one Schedule K-1 to unitholders for the year notwithstanding the two partnership tax years.

A common unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of those common units. If so, the common unitholder would no longer be treated for U.S. federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a common unitholder whose common units are loaned to a "short seller" to effect a short sale may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for U.S. federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the common unitholder and any cash distributions received by the common unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to effect a short sale of common units; therefore, common unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

The issuance of additional i-units may cause more taxable income and gain to be allocated to the common units.

The i-units we issue to KMR generally are not allocated income, gain, loss or deduction for U.S. federal income tax purposes until such time as we are liquidated. Therefore, the issuance of additional i-units may cause more taxable income and gain to be allocated to the common unitholders.

As a result of investing in our common units, a common unitholder will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our common unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our common unitholders will likely be required to file foreign, state and local income tax returns and pay foreign, state and local income taxes in some or all of these various jurisdictions. Further, our common unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in numerous states in the United States and in Canada. It is the responsibility of each common unitholder to file all required U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Unitholders may have negative tax consequences if we default on our debt or sell assets.

If we default on any of our debt, the lenders will have the right to sue us for non-payment. Such an action could cause an investment loss and cause negative tax consequences for unitholders through the realization of taxable income by unitholders without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, unitholders could have increased taxable income without a corresponding cash distribution.

There is the potential for a change of control of our general partner if KMI defaults on debt.

KMI indirectly owns all the common stock of Kinder Morgan G.P., Inc., our general partner. If KMI or Kinder Morgan Kansas, Inc. defaults on its debt, then the lenders under such debt, in exercising their rights as lenders, could acquire control of our general partner or otherwise influence our general partner through control of KMI or Kinder Morgan Kansas, Inc.

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

See Note 16 to our consolidated financial statements included elsewhere in this report.

Item 4. *Mine Safety Disclosures*

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

PART II

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

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported on the New York Stock Exchange, the principal market in which our common units are traded, the amount of cash distributions declared per common and Class B unit, and the fractional i-unit distribution declared per i-unit.

	Price Range			
	High	Low	Declared Cash Distributions	i-unit Distributions
2012				
First Quarter	$ 90.60	$ 80.40	$ 1.20	0.016044
Second Quarter	85.50	74.15	1.23	0.015541
Third Quarter	86.47	78.60	1.26	0.016263
Fourth Quarter	86.32	74.76	1.29	0.015676
2011				
First Quarter	$ 74.51	$ 69.66	$ 1.14	0.017102
Second Quarter	78.00	69.50	1.15	0.017895
Third Quarter	74.00	63.42	1.16	0.017579
Fourth Quarter	84.95	65.00	1.16	0.014863

Distribution information is for distributions declared with respect to that quarter. The declared distributions were paid within 45 days after the end of the quarter. We currently expect to declare cash distributions of $5.28 per unit for 2013; however, no assurance can be given that we will be able to achieve this level of distribution.

Our common units are traded on the New York Stock Exchange under the symbol "KMP." As of January 31, 2013, we had 1,728 unitholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank. Additionally, as of January 31, 2013, there was one holder of our Class B units and one holder of our i-units.

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" and Note 12 "Commitments and Contingent Liabilities—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors" to our consolidated financial statements included elsewhere in this report.

We did not repurchase any units during the fourth quarter of 2012 or sell any unregistered units in the fourth quarter of 2012.

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.

	Year Ended December 31,				
	2012(e)	2011(e)	2010(e)	2009(f)	2008(g)
	(In millions, except per unit and ratio data)				
Income and Cash Flow Data:					
Revenues	$ 8,642	$ 7,889	$ 7,739	$ 6,697	$ 11,362
Operating income	$ 2,340	$ 1,557	$ 1,460	$ 1,367	$ 1,399
Earnings from equity investments	$ 339	$ 224	$ 136	$ 91	$ 76
Income from continuing operations	$ 2,025	$ 1,067	$ 1,092	$ 1,036	$ 1,078
(Loss) income from discontinued operations(a)	$ (669)	$ 201	$ 235	$ 248	$ 240
Net income	$ 1,356	$ 1,268	$ 1,327	$ 1,284	$ 1,319
Limited Partners' interest in net income	$ (78)	$ 83	$ 431	$ 332	$ 499
Limited Partners' net income (loss) per unit:					
Income (loss) per unit from continuing operations	$ 1.64	$ (0.35)	$ 0.65	$ 0.32	$ 1.02
(Loss) income from discontinued operations	(1.86)	0.60	0.75	0.86	0.92
Net (loss) income per unit	$ (0.22)	$ 0.25	$ 1.40	$ 1.18	$ 1.94
Per unit cash distribution declared(b)	$ 4.98	$ 4.61	$ 4.40	$ 4.20	$ 4.02
Ratio of earnings to fixed charges(c)	3.81	2.82	3.07	3.20	3.26
Capital expenditures	$ 1,806	$ 1,199	$ 1,004	$ 1,324	$ 2,533
Balance Sheet Data (at end of period):					
Net property, plant and equipment	$ 19,603	$ 15,596	$ 14,604	$ 14,154	$ 13,241
Total assets	$ 32,094	$ 24,103	$ 21,861	$ 20,262	$ 17,886
Long-term debt(d)	$ 14,714	$ 11,183	$ 10,301	$ 10,022	$ 8,293

(a) Represents income (loss) from the operations and disposal of (i) our Kinder Morgan Interstate Gas Transmission natural gas pipeline system; (ii) our Trailblazer natural gas pipeline system; (iii) our Casper and Douglas natural gas processing operations; (iv) our 50% equity investment in the Rockies Express natural gas pipeline system; and (v) for 2008, our North System natural gas liquids pipeline system. See Notes 1, 2 and 3 of the accompanying notes to our consolidated financial statements for further information about the first four assets listed above.

(b) Represents the amount of cash distributions declared with respect to that year.

(c) For the purpose of computing the ratio of earnings to fixed charges, earnings are defined as income from continuing operations before income taxes, equity earnings (including amortization of excess cost of equity investments) and unamortized capitalized interest, plus fixed charges and distributed income of equity investees. Fixed charges are defined as the sum of interest on all indebtedness (excluding capitalized interest), amortization of debt issuance costs and that portion of rental expense which we believe to be representative of an interest factor.

(d) Excludes debt fair value adjustments. Increases to long-term debt for debt fair value adjustments totaled $1,461 million as of December 31, 2012, $1,055 million as of December 31, 2011, $582 million as of December 31, 2010, $308 million as of December 31, 2009, and $933 million as of December 31, 2008.

(e) For each of the years 2012, 2011 and 2010, includes results of operations for net assets acquired since effective dates of acquisition. For further information on our significant acquisitions for each of these years, see Note 3 to our consolidated financial statements included elsewhere in this report. 2012 also includes results of operations for the net assets of the drop-down asset group for the period beginning May 25, 2012 to the acquisition date. We acquired the drop-down asset group from KMI on August 1, 2012.

(f) Includes results of operations for the terminal assets acquired from Megafleet Towing Co., Inc., the Portland Airport refined products pipeline assets acquired from Chevron Pipe Line Company, the natural gas treating business acquired from Crosstex Energy, L.P. and Crosstex Energy, Inc., and the 40% equity membership interest in Endeavor Gathering LLC acquired from GMX Resources Inc. since effective dates of acquisition. We acquired the terminal assets from Megafleet effective April 23, 2009, the Portland Airport Pipeline assets from Chevron effective July 31, 2009, the natural gas treating business from Crosstex effective October 1, 2009, and the 40% membership interest in Endeavor effective November 1, 2009.

(g) Includes results of operations for the terminal assets acquired from Chemserve, Inc., and the refined petroleum products terminal located in Phoenix, Arizona acquired from ConocoPhillips since effective dates of acquisition. We acquired the terminal assets from Chemserve, Inc. effective August 15, 2008, and we acquired the refined petroleum products terminal from ConocoPhillips effective December 10, 2008. The increase in overall revenues in 2008 was primarily due to incremental revenues earned from the sales of natural gas by our Natural Gas Pipelines business segment.

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 included elsewhere in this report. Additional sections in our Annual Report on Form 10-K for the year ended December 31, 2012, referred to as the 2012 Form 10-K, 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 2012, 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 U.S. generally accepted accounting principles. Accordingly, as discussed in Notes 1, 2, and 3 to our consolidated financial statements included elsewhere in this report, our financial statements reflect:

- the reclassifications necessary to reflect the results of our FTC Natural Gas Pipelines disposal group as discontinued operations. Accordingly, we have excluded the disposal group's financial results from our Natural Gas Pipelines business segment disclosures for the periods presented in this report; and

- our August 1, 2012 acquisition of assets from KMI as if such acquisition had taken place on May 25, 2012, the effective date that KMI acquired the same assets from El Paso Corporation. We refer to this transfer of assets from KMI to us as the drop-down transaction, and we refer to the transferred assets as our drop-down asset group. We accounted for the drop-down transaction as a transfer of net assets between entities under common control, and accordingly, the financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations include the financial results of the drop-down asset group for the period subsequent to May 25, 2012.

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 below 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 energy, bulk commodity and liquids products transportation, storage and distribution; and

- creating long-term value for our unitholders.

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:

- Products Pipelines—the ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Natural Gas Pipelines—the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems, plus the ownership and/or operation of associated natural gas processing and treating facilities;

- CO_2—(i) the production, transportation and marketing of carbon dioxide, referred to as 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;

- Terminals—the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the United States and portions of Canada; and

- Kinder Morgan Canada—(i) 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; (ii) the 33 1/3% interest in the Express crude oil pipeline system, which connects Canadian and U.S. producers to refineries located in the U.S. Rocky Mountain and Midwest regions; and (iii) the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport.

As an energy infrastructure owner and operator in multiple facets of the United States' 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. 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.

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 our Texas Intrastate Natural Gas Group, we currently derive approximately 75% of our 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, 2012, the remaining average contract life of our natural gas transportation contracts (including our intrastate pipelines' purchase and sales contracts) was approximately six years.

Our CO_2 sales and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2012, had a remaining average contract life of approximately 10 years. Carbon dioxide 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 2013, and utilizing the average oil price per barrel contained in our 2013 budget, approximately 72% of our contractual volumes are based on a fixed fee or floor price, and 28% fluctuate with the price of oil. In the long-term, our success in this portion of the CO_2 business segment is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In our CO_2 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, natural gas liquids and carbon dioxide 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. Our realized weighted average crude oil price per barrel, with all hedges allocated to oil, was $87.72 per barrel in 2012, $69.73 per barrel in 2011 and $59.96 per barrel in 2010. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $89.91 per barrel in 2012, $92.61 per barrel in 2011 and $76.93 per barrel in 2010.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. 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 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. Continuing our history of making accretive acquisitions and economically advantageous expansions of existing businesses, in 2012, we invested approximately $2.1 billion for both strategic business acquisitions and expansions of existing assets (not including our August 1, 2012 acquisition of net assets from KMI). Our capital investments have helped us to achieve compound annual growth rates in cash distributions to our limited partners of 8.0%, 5.8% and 7.4%, respectively, for the one-year, three-year and five-year periods ended December 31, 2012.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately $2.9 billion for our 2013 capital expansion program (including small acquisitions and investment contributions, but excluding asset acquisitions from KMI). We regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. These potential acquisitions include the following:

- KMI has offered to sell us (drop-down), in 2013, the remaining 50% ownership interest that we do not already own in (i) EPNG, the sole owner of the El Paso and Mojave natural gas pipeline systems; and (ii) EPMIC, the joint venture that owns both the Altamont natural gas gathering system, processing plant and fractionation facilities located in the Uinta basin of Utah, and the Camino Real natural gas and oil gathering system located in the Eagle Ford shale formation in South Texas; and

- On January 29, 2013, we and Copano Energy, L.L.C. announced a definitive agreement whereby we will acquire all of Copano's outstanding units, including convertible preferred units, for a total purchase price of approximately $5 billion, including the assumption of debt. The transaction is subject to customary closing conditions, regulatory approvals, and a vote of the Copano unitholders; however, TPG Advisors VI, Inc., Copano's largest unitholder, has agreed to support the transaction and we expect the transaction to close in the third quarter of 2013.

  The acquisition of Copano is expected to be accretive to cash available for distribution to our unitholders upon closing. Our general partner, has agreed to forego a portion of its incremental incentive distributions in 2013 in an amount dependent on the time of closing. Additionally, our general partner intends to forgo incentive distribution amounts of $120 million in 2014, $120 million in 2015, and $110 million in 2016 and annual amounts thereafter decreasing by $5 million per year from this level. The transaction is expected to be modestly accretive to us in 2013, given the partial year, and about $0.10 per unit accretive for at least the next five years beginning in 2014.

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 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 a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our 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 our stable cash flows, our investment grade credit rating, and our historical record 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 our public debt and equity offerings in 2012, please see "—Liquidity and Capital Resources" below.

In addition, a portion of our business portfolio (including our Kinder Morgan Canada business segment, the Canadian portion of our Cochin Pipeline, and our 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 U.S. generally accepted accounting principles 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; (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 to our consolidated financial statements included elsewhere in this report. 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.

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.

These environmental liability adjustments are recorded pursuant to our management's requirement to recognize contingent environmental liabilities whenever the associated environmental issue is likely to occur and the amount of our liability can be reasonably estimated. 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 our environmental disclosures, see Note 16 to our consolidated financial statements included elsewhere in this report.

Legal Matters

Many of our operations are regulated by various U.S. and Canadian regulatory bodies and we are subject to litigation and regulatory proceedings 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; 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. When we identify specific litigation that is expected to continue for a significant period of time, is reasonably possible to occur, and may require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement. 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.

As of December 31, 2012, our most significant ongoing litigation proceedings involved our West Coast Products 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 our regulatory proceedings, see Note 16 to our consolidated financial statements included elsewhere in this report.

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, 2012 impairment testing, and no event indicating an impairment has occurred subsequent to that date. For more information on our goodwill, see Notes 2 and 7 to our consolidated financial statements included elsewhere in this report.

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 to our consolidated financial statements included elsewhere in this report.

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 Activities (Unaudited)" included elsewhere in this report.

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 U.S. generally accepted accounting principles, 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.

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 to our consolidated financial statements included elsewhere in this report.

Results of Operations

Consolidated

	Year Ended December 31,		
	2012	**2011**	**2010**
		(In millions)	
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)			
Products Pipelines	$ 670	$ 463	$ 505
Natural Gas Pipelines	1,349	546	576
CO_2	1,322	1,099	965
Terminals	709	704	641
Kinder Morgan Canada	229	202	182
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(b)	4,279	3,014	2,869
Depreciation, depletion and amortization expense(c)	(1,093)	(928)	(879)
Amortization of excess cost of equity investments	(7)	(7)	(6)
General and administrative expenses(d)	(493)	(473)	(375)
Interest expense, net of unallocable interest income(e)	(652)	(531)	(507)
Unallocable income tax expense	(9)	(8)	(10)
Income from continuing operations	2,025	1,067	1,092
(Loss) income from discontinued operations(f)	(669)	201	235
Net income	1,356	1,268	1,327
Net income attributable to noncontrolling interests(g)	(17)	(10)	(11)
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 1,339	$ 1,258	$ 1,316

(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.

(b) 2012, 2011 and 2010 amounts include an increase in earnings of $62 million, a decrease in earnings of $387 million, and a decrease in earnings of $183 million, respectively, related to the combined effect from the 2012, 2011 and 2010 certain items disclosed below in our management discussion and analysis of segment results.

(c) 2012 amount includes a $31 million increase in expense attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012.

(d) 2012, 2011 and 2010 amounts include increases in expense of $70 million, $94 million and $10 million, respectively, related to the combined effect from the 2012, 2011 and 2010 certain items related to general and administrative expenses disclosed below in "—Other."

(e) 2012 and 2010 amounts include increases in expense of $20 million and $1 million, respectively, related to the combined effect from the 2012 and 2010 certain items related to interest expense disclosed below in "—Other."

(f) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount includes a combined $829 million loss from the remeasurement of net assets to fair value and the disposal 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.

(g) 2012, 2011 and 2010 amounts include decreases of $5 million, $7 million and $5 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2012, 2011 and 2010 certain items disclosed below in both our management discussion and analysis of segment results and "—Other."

Distributable Cash Flow

Our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves). Distributable cash flow, sometimes referred to as DCF, is an overall performance metric we use as a measure of available cash. The following table discloses the calculation of our DCF for each of the years ended December 31, 2012, 2011 and 2010 (calculated before the combined effect from all of the 2012, 2011 and 2010 certain items disclosed in the footnotes to the tables above):

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Net Income	$ 1,356	$ 1,268	$ 1,327
Add-back: Certain items - combined expense(a)	888	491	194
Net Income before certain items	2,244	1,759	1,521
Less: Net Income before certain items attributable to noncontrolling interests	(22)	(17)	(16)
Net Income before certain items attributable to Kinder Morgan Energy Partners, L.P.	2,222	1,742	1,505
Less: General Partner's interest in Net Income before certain items(b)	(1,412)	(1,180)	(887)
Less: General Partner's interim capital transaction impact(c)	—	—	(166)
Limited Partners' interest in Net Income before certain items	810	562	452
Depreciation, depletion and amortization(d)	1,252	1,133	1,056
Book (cash) taxes paid, net	(2)	27	26
Incremental contributions from equity investments in the Express Pipeline, Endeavor Gathering LLC and for 2010 only, Eagle Ford Gathering LLC	3	15	5
Sustaining capital expenditures(e)	(285)	(212)	(179)
Distributable cash flow before certain items	$ 1,778	$ 1,525	$ 1,360

(a) Equal to the combined effect from the 2012, 2011 and 2010 items disclosed in the footnotes to the Results of Operations table included above.

Table of Contents

(b) 2012, 2011 and 2010 amounts include reductions of $26 million, $29 million and $18 million, respectively, for waived general partner incentive amounts related to common units issued to finance a portion of our May 2010 and July 2011 KinderHawk Field Services LLC acquisitions.

(c) 2010 amount represents our portion (net of noncontrolling interest) of reduced general partner incentive distribution amount due to a portion of our available cash distribution for the second quarter of 2010 being a distribution of cash from interim capital transactions, rather than a distribution of cash from operations.

(d) 2012, 2011 and 2010 amounts include (i) expense amounts of $176 million, $171 million and $146 million, respectively, for our proportionate share of the depreciation expense associated with the following equity investments: Rockies Express Pipeline LLC; Midcontinent Express Pipeline LLC; Fayetteville Express Pipeline LLC; Cypress Interstate Pipeline LLC; EagleHawk Field Services LLC; Red Cedar Gathering LLC; Eagle Ford Gathering LLC; El Paso Midstream Investment Company LLC; El Paso Natural Gas Pipeline LLC; Bear Creek Storage LLC; and KinderHawk Field Services LLC; and (ii) expense amounts of $7 million, $27 million and $26 million, respectively, from our FTC Natural Gas Pipelines disposal group. 2012 amount also excludes a $31 million expense attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012.

(e) 2012 and 2011 amounts include increases in expenditures of $19 million and $10 million, respectively, for our proportionate share of the sustaining capital expenditures associated with the following equity investments: Rockies Express Pipeline LLC; Midcontinent Express Pipeline LLC; Fayetteville Express Pipeline LLC; Cypress Interstate Pipeline LLC; EagleHawk Field Services LLC; Eagle Ford Gathering LLC; Red Cedar Gathering LLC; El Paso Natural Gas Pipeline LLC; Bear Creek Storage LLC; and El Paso Midstream Investment Company, LLC.

Segment earnings before depreciation, depletion and amortization expenses

With regard to our reportable business segments, we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, (EBDA) to be an important measure of our success in maximizing returns to our partners. 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 five reportable business segments.

For the comparable years of 2012 and 2011, total segment EBDA increased $1,265 million (42%) in 2012; however, this overall increase:

- included a $449 million increase in EBDA from the effect of the certain items described in footnote (b) to the "—Results of Operations" table above; and

- excluded a $71 million decrease in EBDA from discontinued operations (as described in footnote (f) to the "—Results of Operations" table above and excluding both the combined $829 million loss from the remeasurement of net assets to fair value and disposal costs from the sale of net assets in 2012 and the $10 million increase in expense in 2011 from the write-off of a receivable for fuel under-collected prior to 2011).

After adjusting for these two items, the remaining $745 million (20%) increase in segment earnings before depreciation, depletion and amortization in 2012 versus 2011 resulted from higher earnings from all five of our reportable business segments, driven mainly by increases attributable to our Natural Gas Pipelines and CO_2 business segments.

For the comparable years of 2011 and 2010, total segment EBDA increased $145 million (5%) in 2011; however, this overall increase:

- included a $204 million decrease in EBDA from the effect of the certain items described in footnote (b) to the "—Results of Operations" table above; and

- excluded a $23 million decrease in EBDA from discontinued operations (as described in footnote (f) to the "—Results of Operations" table above and excluding the $10 million increase in expense in 2011 from the write-off of a receivable for fuel under-collected prior to 2011).

After adjusting for these two items, the remaining $326 million (10%) increase in segment EBDA in 2011 versus 2010 resulted from better performance from all five of our reportable business segments, primarily due to increases attributable to our CO_2, Natural Gas Pipelines, and Terminals business segments.

Products Pipelines

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except operating statistics)		
Revenues	$ 1,370	$ 914	$ 883
Operating expenses	(759)	(500)	(414)
Other income (expense)	7	10	(4)
Earnings from equity investments	58	51	33
Interest income and Other, net	11	8	16
Income tax (expense)	(17)	(20)	(9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	$ 670	$ 463	$ 505
Gasoline (MMBbl)(b)	395.3	398.0	403.5
Diesel fuel (MMBbl)	141.5	148.9	148.3
Jet fuel (MMBbl)	110.6	110.5	106.2
Total refined product volumes (MMBbl)	647.4	657.4	658.0
Natural gas liquids (MMBbl)	31.7	26.1	25.2
Total delivery volumes (MMBbl)(c)	679.1	683.5	683.2
Ethanol (MMBbl)(d)	33.1	30.4	29.9

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(a) 2012, 2011 and 2010 amounts include decreases in earnings of $33 million, $231 million and $183 million, respectively, related to the combined effect from certain items. 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. 2010 amount consists of a $172 million increase in expense associated with rate case liability adjustments, an $18 million decrease in earnings associated with incremental expenses and losses from the disposal of property related to the sale of a portion of our former Gaffey Street, California terminal land, and a combined $7 million increase in earnings from other certain items.

(b) Volumes include ethanol pipeline volumes.

(c) Includes Pacific, Plantation, Calnev, Central Florida, Cochin, and Cypress pipeline volumes.

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

Combined, the certain items described in the footnotes to the table above accounted for a $198 million increase in segment EBDA in 2012, and a $48 million decrease in EBDA in 2011, when compared with the respective prior year. Following is information related to the segment's (i) remaining $9 million (1%) and $6 million (1%) increases in EBDA; and (ii) $456 million (50%) and $31 million (4%) increases in operating revenues in both 2012 and 2011, when compared with the respective prior year:

Table of Contents

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 %
Crude & Condensate Pipeline	5	230 %	4	n/a
Plantation Pipeline	4	7 %	1	3 %
Southeast Terminals	4	5 %	3	3 %
Transmix operations	(18)	(54)%	447	928 %
Pacific operations	(9)	(3)%	(10)	(2)%
Calnev Pipeline	(8)	(16)%	(6)	(8)%
All others (including eliminations)	9	7 %	13	7 %
Total Products Pipelines	$ 9	1 %	$ 456	50 %

n/a - not applicable

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

- a $22 million (43%) increase from our Cochin natural gas liquids 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 our Kinder Morgan Crude & Condensate Pipeline, which began transporting crude oil and condensate volumes in October 2012.

- a $4 million (7%) increase from our approximate 51% equity interest in the Plantation pipeline system—due largely to higher transportation revenues driven by higher average tariff rates since the end of 2011;

- a $4 million (5%) increase from our 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 our 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, we now directly purchase incremental volumes of transmix and sell incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;

- a $9 million (3%) decrease from our 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 our Calnev Pipeline—chiefly due to an approximate 9% decrease in pipeline delivery volumes that were due in part to incremental services offered by a competing pipeline.

Table of Contents

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline	$ 18	53 %	$ 30	66 %
Plantation Pipeline	9	19 %	1	6 %
West Coast Terminals	8	11 %	10	10 %
Pacific operations	(18)	(6)%	(11)	(3)%
Calnev Pipeline	(5)	(8)%	(4)	(5)%
Transmix operations	(4)	(9)%	3	6 %
All others (including eliminations)	(2)	(2)%	2	1 %
Total Products Pipelines	$ 6	1 %	$ 31	4 %

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The primary increases and decreases in our Products Pipelines business segment's EBDA in 2011 compared to 2010 were attributable to the following:

- an $18 million (53%) increase from our Cochin pipeline system—largely related to a 33% increase in system-wide throughput volumes, partially offset by increased income tax expense due to the year-over-year increase in pre-tax income;

- a $9 million (19%) increase from our equity interest in Plantation. The increase in Plantation's earnings was primarily due to higher oil loss allowance revenues, a 4% increase in transport volumes, and the absence of an expense from the write-off of an uncollectible receivable in the first quarter of 2010;

- an $8 million (11%) increase from our West Coast terminal operations—due mainly to the completion of various terminal expansion projects that increased liquids tank capacity, and partly to higher rates on existing storage;

- an $18 million (6%) decrease from our Pacific operations—due largely to an $11 million decrease in revenues and a $6 million increase in combined operating expenses. The decrease in revenues was primarily due to lower average tariffs, due both to lower rates on the system's East Line deliveries as a result of rate case settlements since the end of 2010, and to lower military tenders. The increase in operating expenses was associated mainly with liability adjustments made pursuant to an adverse tentative court decision on the amount of 2011 rights-of-way lease payment obligations;

- a $5 million (8%) decrease from our Calnev Pipeline—due largely to a 21% drop in ethanol handling volumes that related to both lower deliveries to the Las Vegas market and incremental ethanol blending services offered by a competing terminal; and

- a $4 million (9%) decrease from our transmix processing operations—due mainly to lower product gains relative to 2010.

Natural Gas Pipelines

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except operating statistics)		
Revenues(a)	$ 3,926	$ 3,943	$ 4,078
Operating expenses	(2,817)	(3,370)	(3,583)
Other expense	(1)	—	—
Earnings from equity investments	230	140	82
Interest income and Other, net	6	(164)	2
Income tax benefit (expense)	5	(3)	(3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments from continuing operations(b)	1,349	546	576
Discontinued operations(c)(d)	(662)	228	261
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments including discontinued operations	$ 687	$ 774	$ 837
Natural gas transport volumes (Bcf)(e)	5,866.0	5,273.2	4,514.8
Natural gas sales volumes (Bcf)(e)	879.1	804.7	797.9

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(a) 2012 amount includes an increase of $181 million attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012.

(b) 2012 amount includes an increase in earnings of $131 million attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012, and a combined $11 million increase from other certain items. 2011 amount includes a $167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value.

(c) Represents EBDA attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount includes a combined loss of $829 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.

(d) 2012, 2011 and 2010 amounts include revenues of $227 million, $322 million and $339 million, respectively.

(e) Includes pipeline volumes for TransColorado Gas Transmission Company LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC, Fayetteville Express Pipeline LLC, Tennessee Gas Pipeline Company, L.L.C., El Paso Natural Gas Pipeline Company, L.L.C., Texas intrastate natural gas pipeline group, and for 2010, 2011 and the first ten months of 2012 only, Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC and Rockies Express Pipeline LLC. Volumes for acquired pipelines are included for all periods.

Combined, the certain items described in footnotes (a) through (c) to the table above decreased our Natural Gas Pipelines business segment's EBDA (including discontinued operations) by $510 million in 2012, and by $177 million in 2011, when compared with the respective prior year. In addition, the certain items described in footnotes (a) and (d) to the table above accounted for a $181 million increase in segment revenues in 2012 versus 2011. Following is information, including discontinued operations, related to the segment's remaining (i) $423 million (44%) and $114 million (14%) increases in EBDA; and (ii) $293 million (7%) and $152 million (3%) decreases in operating revenues in 2012 and 2011, when compared with the respective prior year:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Tennessee Gas Pipeline	$ 308	n/a	$ 421	n/a
KinderHawk Field Services(a)	58	52 %	95	96 %
El Paso Natural Gas Pipeline(b)	36	n/a	—	n/a
Kinder Morgan Treating operations	33	70 %	69	79 %
Fayetteville Express Pipeline(b)	31	131 %	—	n/a
Eagle Ford Gathering(b)	23	203 %	—	n/a
Texas Intrastate Natural Gas Pipeline Group	(6)	(2)%	(776)	(22)%
All others (including eliminations)	11	6 %	(7)	(6)%
Total Natural Gas Pipelines-continuing operations	494	69 %	(198)	(5)%
Discontinued operations(c)	(71)	(30)%	(95)	(29)%
Total Natural Gas Pipelines-including discontinued operations	$ 423	44 %	$ (293)	(7)%

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n/a - not applicable

(a) Equity investment until July 1, 2011. See Note (b).

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

(c) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

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

- incremental earnings of $344 million from our drop-down asset group (our Tennessee Gas Pipeline and our 50%-owned El Paso Natural Gas Pipeline), which we acquired from KMI effective August 1, 2012;

- incremental earnings of $58 million from our now wholly-owned KinderHawk Field Services LLC, due principally to the inclusion of a full year of operations in 2012 (we acquired the remaining 50% ownership interest in KinderHawk that we did not already own and began accounting for our 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 our 50% interest in the Fayetteville Express pipeline system—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's refinancing of its prior bank credit facility in July 2011;

- incremental equity earnings of $23 million from our 50%-owned Eagle Ford Gathering LLC, which initiated flow on its natural gas gathering system on August 1, 2011; and

- a $6 million (2%) decrease from our 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 natural gas liquids prices, and the year-over-year decrease in sales margin was due to lower average natural gas sales prices relative 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 our Kinder Morgan Interstate Gas Transmission pipeline system and our Trailblazer pipeline system decreased $29 million (33%) and $20 million (59%), 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 operating 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.

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 92	n/a	$ 99	n/a
Fayetteville Express Pipeline(b)	24	n/a	n/a	n/a
Midcontinent Express Pipeline(b)	12	42 %	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	6	2 %	(252)	(6)%
All others (including eliminations)	3	2 %	18	9 %
Total Natural Gas Pipelines-continuing operations	137	24 %	(135)	(3)%
Discontinued operations(c)	(23)	(9)%	(17)	(5)%
Total Natural Gas Pipelines-including discontinued operations	$ 114	14 %	$ (152)	(3)%

n/a - not applicable

(a) Equity investment until July 1, 2011. See Note (b).

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

(c) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

The primary increases and decreases in our Natural Gas Pipelines business segment's EBDA from continuing operations in 2011 compared to 2010 were attributable to the following:

- a $92 million increase from incremental earnings from KinderHawk Field Services LLC;
- a $24 million increase from incremental equity earnings from our 50% interest in the Fayetteville Express pipeline system, which began firm contract transportation service on January 1, 2011;
- a $12 million (42%) increase in equity earnings from our 50% interest in the Midcontinent Express pipeline system—driven by higher transportation revenues and by the June 2010 completion of an expansion project that increased the system's Zone 1 transportation capacity from 1.5 billion to 1.8 billion cubic feet per day, and Zone 2 capacity from 1.0 billion to 1.2 billion cubic feet per day; and
- a $6 million (2%) increase from our Texas intrastate natural gas pipeline group—primarily due to higher margins from both natural gas storage and transportation services (due to favorable storage price spreads and a 15% increase in transportation volumes) and incremental equity earnings from our 50% interest in Eagle Ford Gathering LLC. The overall increase in earnings was partly offset by lower natural gas sales margins (mainly attributable to higher costs of natural gas supplies relative to sales price), and higher operating expenses (attributable primarily to higher pipeline integrity and remediation expenses).

The primary increases and decreases in our Natural Gas Pipelines business segment's EBDA from discontinued operations in 2011 compared to 2010 were attributable to the following:

- an $18 million (17%) decrease from our Kinder Morgan Interstate Gas Transmission pipeline system— driven by a $12 million decrease due to lower net fuel recoveries, related to both lower recovery factors resulting from a FERC regulatory settlement reached with shippers that became effective June 1, 2011, and lower average collection prices due to an overall drop in natural gas market prices relative to 2010; and

- an $11 million (25%) decrease from our Trailblazer pipeline system—mainly attributable to both a $5 million increase in expense from the write-off of receivables for under-collected fuel (incremental to the $10 million increase in expense that is described in footnote (f) to the results of operations table above and which relates to periods prior to 2011), and a $3 million decrease in natural gas transmission revenues, due largely to lower transportation base rates implemented in 2011 as a result of a 2010 rate case settlement.

The overall changes in both segment revenues and segment operating expenses (from continuing operations) in both pairs of comparable years primarily relate to the natural gas purchase and sale activities of our Texas intrastate natural gas pipeline group, with the variances from year-to-year in both revenues and operating expenses (which include natural gas costs of sales) mainly due to corresponding changes in the intrastate group's average prices and volumes for natural gas purchased and sold. Our intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its natural gas sales revenues are largely offset by corresponding increases and decreases in its natural gas purchase costs. It realizes earnings by capturing the favorable differences between the changes in its gas sales prices, purchase prices and transportation costs, including fuel. Our intrastate group accounted for 73%, 92% and 95%, respectively, of the segment's revenues in 2012, 2011 and 2010, and 91%, 98% and 99%, respectively, of the segment's operating expenses in 2012, 2011 and 2010.

CO_2

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except operating statistics)		
Revenues(a)	$ 1,677	$ 1,416	$ 1,246
Operating expenses	(381)	(342)	(309)
Other income	7	—	—
Earnings from equity investments	25	24	23
Interest income and Other, net	(1)	5	4
Income tax (expense) benefit	(5)	(4)	1
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)(b)	$ 1,322	$ 1,099	$ 965
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(c)	1.2	1.3	1.3
Southwest Colorado carbon dioxide production (net) (Bcf/d)(c)	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	29.0	28.6	29.2
SACROC oil production (net)(MBbl/d)(e)	24.1	23.8	24.3
Yates oil production (gross)(MBbl/d)(d)	20.8	21.7	24.0
Yates oil production (net)(MBbl/d)(e)	9.3	9.6	10.7
Katz oil production (gross)(MBbl/d)(d)	1.7	0.5	0.3
Katz oil production (net)(MBbl/d)(e)	1.4	0.4	0.2
Natural gas liquids sales volumes (net)(MBbl/d)(e)	9.5	8.5	10.0
Realized weighted average oil price per Bbl(f)	$ 87.72	$ 69.73	$ 59.96
Realized weighted average natural gas liquids price per Bbl(g)	$ 50.95	$ 65.61	$ 51.03

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(a) 2012, 2011 and 2010 amounts include unrealized losses of $11 million, unrealized gains of $5 million and unrealized gains of $5 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales.

(b) 2012 amount also includes a $7 million gain from the sale of our ownership interest in the Claytonville oil field unit.

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

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

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

(f) Includes all of our crude oil production properties.

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

Our CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. 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 (i) decreased EBDA and revenues by $9 million in 2012, when compared to 2011; and (ii) decreased revenues by $16 million in 2012, when compared to 2011. For each of the segment's two primary businesses, following is information related to the remaining (i) $232 million (21%) and $134 million (14%) increases in EBDA; and (ii) $277 million (20%) and $170 million (14%) increases in operating revenues in both 2012 and 2011, when compared with the respective prior year:

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	$ 232	21%	$ 277	20%

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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 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, increased oil production at the Katz field unit, and increased oil production at the SACROC field unit. When compared to 2011, our 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 natural gas liquids (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 carbon dioxide 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 carbon dioxide being delivered under higher price contracts; and (ii) heavier weighting of new carbon dioxide contract prices to the price of crude oil; and

- a $22 million (22%) increase in all other operating 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.

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA increase/(decrease)			Revenues increase/(decrease)		
	(In millions, except percentages)					
Oil and Gas Producing Activities	$	96	14%	$	127	13 %
Sales and Transportation Activities		38	14%		55	19 %
Intrasegment Eliminations		—	—		(12)	(23)%
Total CO_2	$	134	14%	$	170	14 %

When compared to 2010, the increase in earnings from the segment's oil and gas producing activities in 2011 was mainly due to the following:

- a $92 million (12%) increase due to higher crude oil sales revenues—due to higher average realized sales prices for U.S. crude oil. Our realized weighted average price per barrel of crude oil increased 16% in 2011 versus 2010. The overall increase in crude oil sales revenues was partially offset, however, by a 4% decrease in oil production volumes (volumes presented in the results of operations table above), due primarily to a general year-over-year decline in production at both the SACROC and Yates field units;

- a $19 million (133%) increase due to higher net profits interest revenues from our 28% net profits interest in the Snyder, Texas natural gas processing plant—driven by higher natural gas liquids prices, increased producing volumes in the last half of 2011, and the favorable impact from the restructuring of certain liquids processing contracts that became effective at the beginning of 2011. The contractual changes increased liquids processing production allocated to the plant, and decreased liquids production allocated to the SACROC field unit;

- a $17 million (9%) increase due to higher natural gas plant products sales revenues—due to a 29% increase in our realized weighted average price per barrel of natural gas liquids. The increase in revenues from higher realized sales prices was partially offset, however, by a 15% decrease in liquids sales volumes, mainly related to the contractual reduction in our net interest in liquids production from the SACROC field (described above); and

- a $30 million (10%) decrease due to higher combined operating expenses—driven primarily by higher carbon dioxide supply expenses that related to both initiating carbon dioxide injections into the Katz field and higher carbon dioxide prices.

The increase in EBDA from the segment's sales and transportation activities in 2011 compared to 2010 was attributable to the following:

- a $43 million (21%) increase due to higher carbon dioxide sales revenues—primarily due to higher average sales prices. The segment's average price received for all carbon dioxide sales in 2011 increased 19% compared to 2010, due largely to the fact that a portion of its carbon dioxide sales contracts were indexed to higher oil prices. In addition, overall carbon dioxide sales volumes increased slightly (1%) in 2011 versus 2010;

- an $8 million (10%) increase due to higher carbon dioxide and crude oil pipeline transportation revenues—due mainly to incremental transportation service on our Eastern Shelf carbon dioxide pipeline. We completed construction of the pipeline in December 2010; and

- a $16 million (30%) decrease due to higher combined operating expenses—driven by higher severance tax expenses and higher carbon dioxide supply expenses, both related to higher commodity prices in 2011.

Table of Contents

Terminals

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except operating statistics)		
Revenues	$ 1,359	$ 1,315	$ 1,265
Operating expenses	(685)	(634)	(629)
Other income	15	1	4
Earnings from equity investments	21	11	1
Interest income and Other, net	2	6	5
Income tax (expense) benefit	(3)	5	(5)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	$ 709	$ 704	$ 641
Bulk transload tonnage (MMtons)(b)	96.6	99.8	92.5
Ethanol (MMBbl)	65.3	61.0	57.9
Liquids leaseable capacity (MMBbl)	60.1	60.2	58.2
Liquids utilization %	93.2%	94.5%	96.2%

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(a) 2012, 2011 and 2010 amounts include a decrease of $43 million, an increase of $3 million, and a decrease of $5 million, respectively, related to the combined effect from certain items. 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 our 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 us from KMI (however, we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense), and a combined $2 million decrease from other certain items. 2010 amount consists of a $7 million decrease in earnings from casualty insurance deductibles and the repair of assets related to casualty losses, and a combined $2 million increase from other certain items.

(b) Volumes for acquired terminals are included for all periods.

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

Combined, the certain items described in the footnotes to the table above decreased segment EBDA by $46 million in 2012 and increased EBDA by $8 million in 2011, when compared with the respective prior year. Following is information related to the segment's (i) remaining $51 million (7%) and $55 million (9%) increases in EBDA; and (ii) $44 million (3%) and $50 million (4%) increases in operating revenues in both 2012 and 2011, when compared with the respective prior year:

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	$ 51	7 %	$ 44	3 %

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The overall increases in EBDA from our Terminals segment were driven by higher contributions from the terminal facilities included in our Gulf Liquids, Mid-Atlantic and Northeast regions. The increase from our Gulf Liquids facilities were driven by higher warehousing revenues (as a result of new and renewed customer agreements at higher rates) at our Galena Park and Pasadena, Texas facilities, higher ethanol volumes through our Deer Park, Texas rail terminal, and higher overall gasoline throughput volumes. We also benefited from both higher capitalized overhead associated with the ongoing construction of our majority-owned Battleground Texas oil terminal located on the Houston Ship Channel, and higher earnings from our crude oil storage operations located in Cushing, Oklahoma.

The year-to-year earnings increase from our Mid-Atlantic region resulted primarily from higher export coal shipments from our Pier IX terminal, located in Newport News, Virginia, and higher import steel and iron ore imports from our Fairless Hills, Pennsylvania bulk terminal. Economic expansion in developing countries has generated a growth cycle in the coal export market. Due both to this growth in demand and to completed infrastructure expansions since the end of 2011, our 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 our Northeast terminal operations was driven by higher contributions from our Staten Island terminal due to new and favorable contract changes. Despite being affected heavily by hurricane Sandy in 2012, our liquid terminal in Carteret, New Jersey increased earnings primarily due to higher transfer and storage rates, and to new and renegotiated contracts. We also benefited from incremental earnings from our Philadelphia liquids terminal, due largely to new and restructured customer contracts at higher rates, and from our 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 our additional equity investment in the short-line railroad operations of Watco Companies, LLC (acquired in December 2011) and our bulk terminal that handles petroleum coke for the Total refinery in Port Arthur, Texas (acquired in June 2011). 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 we owned the assets in 2011.

The remaining increases and decreases in our Terminals 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 our 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.

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic	$ 20	53 %	$ 28	30 %
Acquired assets and businesses	15	n/a	12	n/a
Northeast	9	12 %	13	10 %
Gulf Liquids	9	5 %	20	10 %
Midwest	5	12 %	7	7 %
Southeast	3	6 %	3	2 %
Ohio Valley	(4)	(12)%	(1)	(2)%
West	(4)	(6)%	(6)	(5)%
All others (including intrasegment eliminations and unallocated income tax expenses)	2	1 %	(26)	(6)%
Total Terminals	$ 55	9 %	$ 50	4 %

The increase in earnings from the terminals included in our Mid-Atlantic region was driven by an $18 million increase from our Pier IX terminal, located in Newport News, Virginia. Pier IX benefited from a $21 million increase in operating revenues that related chiefly to a 5.2 million ton (74%) increase in coal transload volumes. The increase in volumes was due to the ongoing domestic economic recovery, growth in the export market (due to greater foreign demand for both U.S. metallurgical and steam coal), and completed terminal expansions since the end of 2010. Including all terminals, coal volumes handled increased by 20% in 2011 compared to 2010.

The incremental earnings and revenues from acquired assets and businesses primarily represent contributions from (i) our initial equity investment in Watco Companies, LLC (acquired in January 2011); (ii) our Port Arthur petroleum coke bulk terminal (acquired in June 2011 and discussed above); and (iii) the bulk and liquids terminal assets we acquired from Slay Industries in March 2010. For more information on our 2011 terminal acquisitions, see Note 3 to our consolidated financial statements included elsewhere in this report.

The increase in earnings from our Northeast terminals was primarily due to a $7 million increase from our Carteret, New Jersey liquids terminal, driven by both completed liquids tank expansion projects since the end of 2010 (which increased liquids storage capacity by approximately one million barrels), and higher transfer and storage rates. Including all terminals, we increased our liquids terminals' leasable capacity by 2.0 million barrels (3.4%) during 2011, via both terminal acquisitions and completed terminal expansion projects and, at the same time, our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) at the end of 2011 decreased by only 1.7% since the end of 2010.

The increase in earnings from our Gulf Liquids terminals primarily related to higher operating results from our Galena Park and Pasadena liquids facilities, driven by higher ethanol volumes, higher distillate warehousing revenues, and new and renewed customer agreements at higher rates. We also benefited from the March 2011 completion of our Deer Park Rail Terminal and its related ethanol handling assets at our Pasadena terminal. For all of our Gulf Liquids terminals combined, total ethanol handling volumes increased by 86% in 2011 compared to 2010.

The overall increase in earnings from our Midwest terminals was mainly due to higher earnings from the combined operations of our Argo and Chicago, Illinois liquids terminals, due to increased ethanol throughput and incremental liquids storage and handling business, and to higher contributions from our Dakota Bulk terminal located in St. Paul, Minnesota, due to higher sand and salt transload volumes.

The increase in earnings from our Southeast terminals was due mainly to higher chemical revenues, increased salt handling, and higher storage fees at our Shipyard River Terminal, located in Charleston, South Carolina, and to higher margins from tank blending services involving various agricultural products at our liquids terminal facility located in Wilmington, North Carolina.

Higher overall earnings from our Terminals segment in 2011 versus 2010 were partially offset by lower earnings from terminal operations included in the segment's Ohio Valley and West regions, due mainly to both lower revenues earned from steel handling and iron ore stevedoring services, and lower agricultural exports due to higher soybean meal exports during 2010 as a result of drought conditions in South America.

The remaining increases and decreases in our Terminals 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 decrease in revenues relate largely to terminal assets we sold (or contributed to joint ventures) and no longer consolidate since the end of 2010.

Kinder Morgan Canada

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except operating statistics)		
Revenues	$ 311	$ 302	$ 268
Operating expenses	(103)	(97)	(91)
Earnings from equity investments	5	(2)	(3)
Interest income and Other, net	17	14	16
Income tax (expense)	(1)	(15)	(8)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	$ 229	$ 202	$ 182
Transport volumes (MMBbl)(b)	106.1	99.9	108.4

(a) 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 us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense).

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and our one-third ownership interest in the Express crude oil pipeline system. The certain item relating to income tax savings described in footnote (a) to the table above accounted for both a $3 million decrease in segment EBDA in 2012, and a $3 million increase in EBDA in 2011, when compared with the respective prior year.

Following is information related to the segment's (i) remaining $30 million (15%) and $17 million (9%) increases in EBDA; and (ii) $9 million (3%) and $34 million (13%) increases in operating revenues in both 2012 and 2011, when compared with the respective prior year:

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	$ 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 our 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.

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 21	13 %	$ 34	13%
Express Pipeline	(4)	(26)%	—	—
Total Kinder Morgan Canada	$ 17	9 %	$ 34	13%

The overall increase in Trans Mountain's EBDA in 2011 compared to 2010 included an increase of $5 million due to favorable currency impacts, primarily related to favorable changes from the translation of earnings.

Trans Mountain's remaining $16 million year-over-year increase in EBDA was driven by higher operating revenues, primarily due to favorable impacts from a negotiated pipeline toll settlement agreement which became effective on January 1, 2011. The one-year negotiated toll agreement was formally approved by the National Energy Board (Canada) on April 29, 2011, and replaced the previous mainline toll settlement agreement that expired on December 31, 2010.

The decrease in earnings from our investment in the Express pipeline system was driven by a $5 million increase in income tax expenses, due to a drop in income tax expense in 2010 related to a valuation allowance release on previously established deferred tax balances. The overall decrease in earnings was partially offset by a $1 million increase in equity earnings, primarily due to higher domestic transportation volumes on the Platte Pipeline segment.

Other

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
General and administrative expenses(a)	$ 493	$ 473	$ 375
Interest expense, net of unallocable interest income(b)	$ 652	$ 531	$ 507
Unallocable income tax expense	$ 9	$ 8	$ 10
Net income attributable to noncontrolling interests(c)	$ 17	$ 10	$ 11

(a) 2012, 2011 and 2010 amounts include increases in expense of $70 million, $94 million and $10 million, respectively, related to the combined effect from certain items. 2012 amount consists of a $56 million increase in expense attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012, an $8 million increase in unallocated severance expense, and a combined $6 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 us from KMI; however, we do not have any obligation, nor did we pay any amounts related to this expense, and a combined $4 million increase in expense from other certain items. 2010 amount consists of $5 million increase in non-cash compensation expense allocated to us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this expense), and a combined $5 million increase in expense from other certain items.

(b) 2012 and 2010 amounts include increases in expense of $20 million and $1 million, respectively, related to the combined effect from certain items. 2012 amount consists of a $21 million increase in expense attributable to our drop-down asset group for the period prior to our acquisition date of August 1, 2012, and a combined $1 million decrease in expense from other certain items. 2010 amount consists of a $1 million increase in imputed interest expense, related to our January 1, 2007 Cochin Pipeline acquisition.

(c) 2012, 2011 and 2010 amounts include decreases of $5 million, $7 million and $5 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2012, 2011 and 2010 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as unallocated salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services. These expenses are generally not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. For this reason and because we manage our business based on our reportable business segments and not on the basis of our ownership structure, we do not specifically allocate our general and administrative expenses to our business segments. As discussed previously, we use segment EBDA internally as a measure of profit and loss used for evaluating segment performance, and each of our segment's EBDA includes all costs directly incurred by that segment.

Combined, the certain items described in footnote (a) to the table above decreased our general and administrative expenses by $24 million in 2012, and increased our general and administrative expenses by $84 million in 2011, when compared with the respective prior year. The remaining $44 million (12%) increase in general and administrative expenses in 2012 versus 2011 was driven by the acquisition of additional business, associated primarily with the Tennessee Gas and El Paso Natural Gas (50% interest) pipeline systems we acquired from KMI effective August 1, 2012. We also realized higher benefit and payroll tax expenses, and higher employee labor expenses, which were impacted by cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force. The remaining $14 million (4%) increase in general and administrative expenses in 2011 compared to 2010 was driven by (i) a combined $11 million increase due to higher employee benefits and payroll tax expenses (due mainly to both cost inflation increases on work-based health and insurance benefits and higher wage rates); (ii) higher overall salary and labor expenses; and (iii) higher environmental and pension expenses related to our Canadian pipeline operations.

In the table above, we report our interest expense as "net," meaning that we have subtracted unallocated interest income and capitalized interest from our interest expense to arrive at one interest amount, and after taking into effect the certain items described in footnote (b) to the table above, our unallocable interest expense increased $101 million (19%) in 2012 compared to 2011, and increased $25 million (5%) in 2011 compared to 2010. For both pairs of comparable years, the increase in interest expense was attributable to higher average borrowings.

Our average debt balances increased 18% in 2012 and 10% in 2011, when compared to the respective prior year. The increases in average borrowings were largely due to the capital expenditures, external business acquisitions (including debt assumed from the drop-down transaction), and investment contributions we have made since the beginning of 2010. For more information on our capital expenditures, capital contributions, and acquisition expenditures, see "—Liquidity and Capital Resources."

The weighted average interest rate on all of our borrowings—including both short-term and long-term amounts—was essentially flat across both 2012 and 2011, but decreased by 2% in 2011 versus 2010 (the weighted average interest rate on all of our borrowings was 4.24% during 2012, 4.26% during 2011 and 4.35% during 2010). The lower average rate in 2011 was due primarily to a decrease in the variable interest rate we paid on the borrowings made under our commercial paper program as compared to borrowing under our revolving bank credit facility in 2010.

We use interest rate swap agreements to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt, and as of December 31, 2012, approximately 39% of our consolidated debt balances (excluding debt fair value adjustments) was 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. As of December 31, 2011, approximately 47% of our consolidated debt balances (excluding debt fair value adjustments) was subject to variable interest rates. For more information on our interest rate swaps, see Note 13 to our consolidated financial statements included elsewhere in this report.

Liquidity and Capital Resources

General

As of December 31, 2012, we had $518 million of "Cash and cash equivalents" on our consolidated balance sheet (included elsewhere in this report), an increase of $109 million (27%) from December 31, 2011. We also had, as of December 31, 2012, approximately $1.4 billion of borrowing capacity available under our $2.2 billion senior unsecured revolving credit facility (discussed below in "—Short-term Liquidity"). We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;

- expansion capital expenditures and working capital deficits with retained cash (which may result from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings (including commercial paper issuances), and the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;

- interest payments with cash flows from operating activities; and

- debt principal payments, as such debt principal payments become due, with additional borrowings or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

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

Credit Ratings and Capital Market Liquidity

Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (stable) and BBB (stable), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. Our short-term corporate debt credit rating is A-2 (susceptible to adverse economic conditions, however, capacity to meet financial commitments is satisfactory), Prime-2 (strong ability to repay short-term debt obligations) and F2 (good quality grade with satisfactory capacity to meet financial commitments), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. Our credit ratings affect our ability to access the commercial paper market and the public and private debt markets, as well as the terms and pricing of our debt (see Part I, Item 1A "Risk Factors"). Based on these credit ratings, we expect that our short-term liquidity needs will be met primarily through borrowings under our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our 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.

Short-term Liquidity

As of December 31, 2012, our principal sources of short-term liquidity were (i) our $2.2 billion senior unsecured revolving credit facility with a diverse syndicate of banks that matures July 1, 2016; (ii) our $2.2 billion short-term commercial paper program (which is supported by our credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings and letters of credit); and (iii) cash from operations (discussed below in "—Operating Activities"). The loan commitments under our revolving credit facility can be used to fund borrowings for general partnership purposes and as a backup for our commercial paper program, and our $2.2 billion long-term senior unsecured revolving credit facility can be amended to allow for borrowings of up to $2.5 billion. As of both December 31, 2012 and 2011, we had no outstanding borrowings under our credit facility.

Our outstanding short-term debt as of December 31, 2012 was $1,155 million, primarily consisting of (i) $621 million of outstanding commercial paper borrowings; and (ii) $500 million in principal amount of 5.00% senior notes that mature December 15, 2013. As of December 31, 2011, our outstanding short-term debt was $1,638 million, primarily consisting of (i) $645 million of commercial paper borrowings; (ii) $450 million in principal amount of 7.125% senior notes that matured March 15, 2012; and (iii) $500 million in principal amount of 5.85% senior notes that matured September 15, 2012. We intend to refinance our 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.

We had a working capital deficit of $921 million as of December 31, 2012, and a working capital deficit of $1,543 million as of December 31, 2011. The overall $622 million (40%) favorable change from year-end 2011 was primarily due to the $483 million decrease in short-term debt discussed above. 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 cash and cash equivalent balances as a result of debt or equity issuances (discussed below in "—Long-term Financing").

We employ a centralized cash management program for our U.S.-based bank accounts that essentially concentrates the cash assets of our operating partnerships and their subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. Our centralized cash management program provides that funds in excess of the daily needs of our operating partnerships and their subsidiaries are concentrated, consolidated, or otherwise made available for use by other entities within our consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to parent companies other than restrictions that may be contained in agreements governing the indebtedness of those entities. However, our cash and the cash of our subsidiaries is not concentrated into accounts of KMI or any company not in our consolidated group of companies, and KMI has no rights with respect to our cash except as permitted pursuant to our partnership agreement.

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

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions of cash from operations to our common unitholders, Class B unitholder and general partner) through issuing long-term debt securities or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

Our equity offerings consist of the issuance of additional common units or the issuance of additional i-units to KMR (which KMR purchases with the proceeds from the sale of additional KMR shares). As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors. For more information about our equity issuances during 2012, see Note 10 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. Our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate senior notes provide that we may redeem the notes 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.

In addition, from time to time our subsidiary Tennessee Gas Pipeline Company, L.L.C. (TGP) has issued long-term debt securities, often referred to as its senior notes. As of December 31, 2012, TGP is the obligor of six separate series of fixed-rate unsecured senior notes having a combined principal amount of $1,790 million. The interest rates on these notes range from 7% per annum through 8.375% per annum, and the maturity dates range from February 2016 through April 2037. We assumed these senior notes as part of the drop-down transaction.

As of December 31, 2012 and 2011, the aggregate principal amount of the various series of our senior notes was $13,350 million and $12,050 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries (including TGP's senior notes discussed above) was $1,898 million and $126 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt obligations and our debt related transactions in 2012, see Note 8 "Debt" to our consolidated financial statements included elsewhere in this report.

Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term senior notes in the future. If we were unable or unwilling to issue additional limited partner units, 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 credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, financing our expansion capital expenditures and acquisitions with approximately 50% equity and 50% debt. In the short-term, we fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both. With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable interest rates. We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset. For the years ended December 31, 2012 and 2011, our sustaining capital expenditures totaled $285 million and $212 million, respectively. These amounts included $19 million and $10 million, respectively, for our proportionate share of the unconsolidated joint venture sustaining capital expenditures of (i) Midcontinent Express Pipeline LLC; (ii) Fayetteville Express Pipeline LLC; (iii) Cypress Interstate Pipeline LLC; (iv) EagleHawk Field Services LLC; (v) Eagle Ford Gathering LLC; (vi) Red Cedar Gathering Company; (vii) Rockies Express Pipeline LLC; (viii) KinderHawk Field Services LLC; (ix) El Paso Natural Gas Pipeline Company, L.L.C.; (x) Bear Creek Storage Company, L.L.C.; and (xi) El Paso Midstream Investment Company, LLC.

We forecasted $339 million for sustaining capital expenditures in our 2013 budget. This amount includes $6 million for our proportionate share of our unconsolidated joint ventures' (described above) sustaining capital expenditures. Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Midcontinent Express and Fayetteville Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, with proceeds from issuing their own long-term notes, or with proceeds from contributions received from their member owners. We have no contingent debt obligations with respect to Midcontinent Express, or Fayetteville Express.

In addition to the sustaining capital expenditures described above (excluding the proportionate share of the sustaining capital expenditures of our unconsolidated joint ventures also described above), our consolidated statements of cash flows for the years ended December 31, 2012 and 2011 included capital expenditures of $1,540 million and $997 million, respectively. We report our total consolidated capital expenditures separately as "Capital expenditures" within the "Cash Flows from Investing Activities" section on our accompanying cash flow statements (included elsewhere in this report), and the overall $607 million (51%) year-to-year increase in our consolidated capital expenditures in 2012 versus 2011 was primarily due to higher investment undertaken to expand and improve our Terminals and Natural Gas Pipelines business segments. The overall $195 million (19%) increase in our consolidated capital expenditures in 2011 compared to 2010 was primarily due to higher investment undertaken in 2011 to expand and improve our Products Pipelines and CO_2 business segments.

We forecasted $2,470 million for discretionary capital expenditures in our 2013 budget. This amount does not include forecasted discretionary expenditures by our equity investees, forecasted capital contributions to our equity investees, or forecasted expenditures for asset acquisitions. Generally, we initially fund our capital expenditures through borrowings under our commercial paper program or our revolving credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

Capital Requirements for August 2012 Drop-Down Transaction

In 2012, our cash outlays for the drop-down transaction totaled $3,482 million (net of an acquired cash balance of $3 million) and we reported this amount separately as "Payment to KMI for drop-down asset group, net of cash acquired" on our accompanying consolidated statement of cash flow included elsewhere in this report. With the exception of our partial payment of the combined purchase price to KMI by the issuance of addition common units (valued at $381 million), we funded this acquisition with proceeds received from (i) our August 2012 issuance of long-term senior notes; (ii) our third quarter 2012 issuances of additional i-units to KMR; (iii) our third and fourth quarter issuances of additional common units; (iv) borrowings under our short-term bridge loan credit facility; and (v) borrowings under our commercial paper program. We subsequently repaid the borrowings made under our short-term bridge loan credit facility with proceeds received from the sale of our FTC Natural Gas Pipelines disposal group, and we terminated our bridge loan credit facility on November 16, 2012.

Additional Capital Requirements

In 2012, we announced that we will proceed with our proposal to expand our existing Trans Mountain pipeline system. When completed, the proposed expansion will increase capacity on Trans Mountain from its current 300,000 barrels per day of crude oil and refined petroleum products to approximately 890,000 barrels per day. In 2012, we confirmed binding commercial support for this project, and pending the filing and approval of tolling and facilities applications with the NEB, we expect to begin construction in 2015 or 2016, with the proposed project operating in late 2017. Our current estimate of total construction costs on the project is approximately $5.4 billion. Trans Mountain is currently in the final stages of securing NEB approval for the commercial terms of the expansion. Failure to secure NEB approval of this project at a reasonable toll rate could require us to either delay or cancel this project. We anticipate NEB's approval in the second quarter of 2013.

As described above in "—General," KMI has offered to sell both its 50% ownership interest in EPNG and its 50% ownership interest in EPMIC to us in 2013 (in a future drop-down transaction). We would expect to fund the purchase price of these drop-down assets by the issuance of additional common units and/or incremental borrowings under our commercial paper program.

With regard to our definitive agreement to acquire all of Copano Energy, L.L.C.'s outstanding units, the transaction, will be a 100% unit for unit transaction with an exchange ratio of 0.4563 of our common units for each Copano unit. The transaction is subject to customary closing conditions, regulatory approvals, and a vote of the Copano unitholders; however, it has been approved by the board of directors of both our general partner and Copano, and TPG Advisors VI, Inc., Copano's largest unitholder, has agreed to support the transaction. We expect the transaction to close in the third quarter of 2013.

In addition, we regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. Such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations. For the year 2013, we have forecasted to invest approximately $2.9 billion for our capital expansion program (including small acquisitions and contributions to joint ventures, but excluding acquisitions from KMI and the Copano acquisition).

Our ability to make accretive acquisitions (i) is a function of the availability of suitable acquisition candidates at the right cost; (ii) is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions; and (iii) 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 ability to expand our assets is also impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such expansions.

As a master limited partnership, we distribute all of our available cash (except to the extent that we retain cash from the payment of distributions on i-units in additional i-units) and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our 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 our stable cash flows, our investment grade credit rating, and our historical record 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.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 12 to our consolidated financial statements included elsewhere in this report. Additional information regarding the nature and business purpose of our investments is included in Note 6 to our consolidated financial statements included elsewhere in this report.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In millions)		
Contractual Obligations:					
Debt borrowings-principal payments	$ 15,869	$ 1,155	$ 801	$ 1,650	$ 12,263
Interest payments(a)	13,547	913	1,733	1,572	9,329
Lease obligations(b)	278	54	83	62	79
Pension and postretirement welfare plans(c)	108	9	19	20	60
Other obligations(d)	8	7	1	—	—
Total	$ 29,810	$ 2,138	$ 2,637	$ 3,304	$ 21,731
Other commercial commitments:					
Standby letters of credit(e)	$ 290	$ 290	$ —	$ —	$ —
Capital expenditures(f)	$ 607	$ 607	$ —	$ —	$ —

(a) Interest payment obligations exclude adjustments for interest rate swap agreements and assumes no change in variable interest rates from those in effect at December 31, 2012.

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

(c) Represents expected benefit payments from pension and postretirement welfare plans as of December 31, 2012.

(d) For the Less than 1 year column, represents (i) $6 million due under carbon dioxide take-or-pay contracts; and (ii) $1 million due pursuant to our purchase and sale agreement with Slay Industries for the acquisition of certain bulk and liquid terminal assets effective March 5, 2010. For the 1 to 3 year column, represents amount due under carbon dioxide take-or-pay contracts.

(e) The $290 million in letters of credit outstanding as of December 31, 2012 consisted of the following: (i) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) our $30 million guarantee under letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (iii) a $45 million letter of credit supporting our pipeline and terminal operations in Canada; (iv) a $25 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (v) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (vi) a $15 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; (vii) a $12 million letter of credit supporting debt securities issued by the Express pipeline system; (viii) a $5 million letter of credit supporting our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (ix) a combined $18 million in twelve letters of credit supporting environmental and other obligations of us and our subsidiaries.

(f) Represents commitments for the purchase of plant, property and equipment as of December 31, 2012.

Operating Activities

Net cash provided by operating activities was $3,177 million in 2012, versus $2,874 million in 2011. The overall year-to-year increase of $303 million (11%) in cash flows from operations primarily consisted of:

- a $396 million increase in cash from overall higher partnership income—after adjusting our year-to-year $88 million increase in net income for the following five non-cash items: (i) a $584 million increase from higher non-cash losses from both the remeasurement of net assets to fair value (discussed further in Note 3 to our consolidated financial statements included elsewhere in this report) and the sale of our FTC Natural Gas Pipelines disposal group; (ii) a $145 million increase due to higher depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); (iii) a $240 million decrease related to higher non-cash expenses in 2011 as a result of adjustments to our rate case, leased rights-of-ways and other legal liabilities; (iv) a $98 million decrease due to higher earnings from equity investees in 2012; and (v) an $83 million decrease due to certain higher non-cash compensation and severance expenses allocated to us from KMI in 2011 (as discussed in Note 11 "Related Party Transactions—Non-Cash Compensation and Severance Expenses" to our consolidated financial statements included elsewhere in this report, we do not have any obligation, nor did we pay any amounts related to these allocated expenses). The year-to-year change in partnership income in 2012 versus 2011 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes);

- an $80 million increase in cash from higher distributions of earnings from equity investees, primarily due to incremental distributions received from the El Paso and Fayetteville Express natural gas pipeline systems; and

- a $196 million decrease in cash related to net changes in both non-current assets and liabilities, including, among other things, lower net dock premiums and toll collections received from our Trans Mountain pipeline system customers.

Investing Activities

Net cash used in investing activities was $3,501 million for the year ended December 31, 2012, compared to $2,417 million for the prior year. The year-to-year $1,084 million (45%) decrease in cash due to higher cash expended for investing activities was primarily attributable to the following:

- a $3,482 million decrease from our cash outlay (net of an acquired cash balance of $3 million) as partial payment for the drop-down asset group in August 2012, as described above in "—Capital Requirements for August 2012 Drop-Down Transaction;"

- a $607 million decrease in cash due to higher capital expenditures, as described above in "—Capital Expenditures;"

- a $1,791 million increase in cash from the proceeds we received from the disposal of our FTC Natural Gas Pipelines disposal group; and

- a $1,096 million increase in cash due to lower expenditures for the acquisitions of assets and investments from unrelated parties. In 2012, we paid a combined $83 million for asset acquisitions, including (i) $30 million to Enhanced Oil Resources to acquire a carbon dioxide source field and related assets located in Apache County, Arizona, and Catron County, New Mexico; and (ii) $28 million to Lincoln Oil Co. Inc. to acquire an ethanol and biodiesel terminaling facility located in Belton, South Carolina. In 2011, we spent a aggregate amount of $1,179 million for asset and investment acquisitions, including (i) $835 million for both our remaining 50% ownership interest in KinderHawk Field Services LLC and our 25% equity interest in EagleHawk Field Services LLC; (ii) $152 million for natural gas treating assets acquired from SouthTex Treaters, Inc.; (iii) $100 million for a preferred equity interest in Watco Companies, LLC; and (iv) $43 million for a newly constructed petroleum coke terminal located in Port Arthur, Texas.

Financing Activities

Net cash provided by financing activities amounted to $425 million for 2012. In the comparable prior year, we used $169 million in cash from financing activities. The $594 million (351%) overall increase in cash in 2012 versus 2011 was mainly due to the following:

- a $681 million increase in cash due to higher partnership equity issuances. This increase reflects the $1,636 million we received, after commissions and underwriting expenses, from the sales of additional common units and i-units in 2012, versus the $955 million we received from the sales of additional common units in 2011. All of our 2012 and 2011 equity issuances are discussed in Note 10 to our consolidated financial statements included elsewhere in this report;

- a $153 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. This increase in cash was primarily due to (i) a $154 million increase due to the immediate repayment of all of the outstanding borrowings under KinderHawk Field Services LLC's bank credit facility that we assumed on our July 1, 2011 acquisition date; (ii) a combined $144 million increase due to higher net issuances of our senior notes (in 2012 and 2011, we generated net proceeds of $1,280 million and $1,136 million, respectively, from both issuing and repaying senior notes); and (iii) a $147 million decrease due to lower short-term net borrowings under our commercial paper program. For more information about our debt financing activities, see Note 8 to our consolidated financial statements included elsewhere in this report;

- a $78 million increase in cash from incremental contributions received from both noncontrolling interests and our general partner; and

- a $317 million decrease in cash due to higher partnership distributions. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our noncontrolling interests, totaled $2,560 million in 2012, versus $2,243 million in 2011. For further information regarding our 2012 and 2011 partnership distributions, see Notes 10 and 11 to our consolidated financial statements included elsewhere in this report.

Noncash Investing and Financing Activities

In June 2012, we issued an aggregate consideration of $289 million in common units for the acquisition of a 50% ownership interest in El Paso Midstream Investment Company, LLC, and in August 2012, we issued an aggregate consideration of $381 million in common units as partial payment for the drop-down asset group. We included both of these amounts within "Noncash Investing and Financing Activities—Assets acquired or liabilities settled by the issuance of common units" on our accompanying consolidated statement of cash flows for the year ended December 31, 2012 included elsewhere in this report.

Recent Accounting Pronouncements

Please refer to Note 18 to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

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, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions 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 ability to complete our proposed merger with Copano;

- failure to obtain, delays in obtaining or adverse conditions contained in, any required regulatory approvals or clearances for our proposed merger with Copano;

- the potential impact of the announcement or consummation of the proposed merger with Copano on relationships, including with employees, suppliers, customers and competitors;

- our ability to successfully integrate Copano's operations and to realize synergies from the proposed merger;

- the terms and timing of the proposed drop-down of assets from KMI;

- the timing and extent of changes in price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, 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 implemented by the Federal Energy Regulatory Commission, the California Public Utilities Commission, Canada's National Energy Board or another regulatory agency;

- our ability to acquire new businesses and assets and integrate those operations into our existing 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 access or construct new pipeline, gas processing and NGL fractionation capacity;

- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;

- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;

- 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, Pennsylvania and Texas, 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 and natural gas production or reserves that we may experience;

- the ability to complete expansion projects on time and on budget;

- the timing and success of our business development efforts;

- 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 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, and/or place us at competitive disadvantages 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 greater than our insurance coverage limits;

- possible changes in credit ratings;

- capital and credit markets conditions, inflation and 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 timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in developing and producing oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 16 to our consolidated financial statements included elsewhere in this report.

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, 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.

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 in order to maintain a more stable and predictable earnings stream. Stated another way, we execute 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, natural gas liquids and crude oil. The derivative contracts we use include energy products traded on the New York Mercantile Exchange and over-the-counter markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps.

Fundamentally, our hedging strategy involves taking a simultaneous position in the futures market that is equal and opposite to our 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, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby directly offsetting any change in prices, either positive or negative. A hedge is successful when gains or losses in the cash market are neutralized by losses or gains in the futures transaction.

Our policies require that we only enter into derivative contracts 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 we 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 Ratings Services):

	Credit Rating
J. Aron & Company / Goldman Sachs	A-
Bank of America / Merrill Lynch	A-
Deutsche Bank	A+

As discussed above, our 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, natural gas liquids and crude oil. Using derivative contracts for this purpose helps provide us increased certainty with regard to our operating cash flows and helps us undertake further capital improvement projects, attain budget results and meet distribution targets to our partners. We 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 included within

"Accumulated other comprehensive income" in our accompanying consolidated balance sheets but not included in our net income (portions attributable to our noncontrolling interests are included 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) 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 income" (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. For more information on our other comprehensive income and our "Accumulated other comprehensive income," see Notes 2 and 13 to our consolidated financial statements included elsewhere in this report.

We measure the risk of price changes in our natural gas and crude oil 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 both December 31, 2012 and December 31, 2011, a hypothetical 10% movement in underlying commodity natural gas prices would affect the estimated fair value of our natural gas derivatives by $7 million and $4 million, respectively. As of both December 31, 2012 and December 31, 2011, a hypothetical 10% movement in underlying commodity crude oil prices would affect the estimated fair value of our crude oil derivatives by $196 million and $194 million, respectively. As discussed above, we enter into our 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 and crude oil 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. For more information on our energy commodity risk management activities, see Note 13 to our consolidated financial statements included elsewhere in this report.

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, we do not have 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 our fixed rate debt until we would be required to refinance such debt.

As of December 31, 2012 and 2011, the carrying values of our fixed rate debt (including our debt fair value adjustments) were $16,620 million and $13,142 million, respectively. These amounts compare to, as of December 31, 2012 and 2011, fair values of $18,201 million and $13,504 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 2012 and 2011, would result in changes of approximately $644 million and $526 million, respectively, in the fair values of these instruments.

The carrying value and fair value of our variable rate debt, excluding the value of interest rate swap agreements (discussed following), was $710 million as of December 31, 2012 and $734 million as of December 31, 2011. As of December 31, 2012 and 2011, we were a party to interest rate swap agreements with notional principal amounts of $5.5 billion and $5.3 billion, 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 42 basis points in 2012 and 43 basis points in 2011), when applied to our outstanding balance of variable rate debt as of December 31, 2012 and 2011, including adjustments for the notional swap amounts described above, would result in changes of approximately $26 million in both our 2012 and 2011 annual pre-tax earnings.

We entered into our interest rate swap agreements for the purpose of transforming a portion of the underlying cash flows related to our 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 our fixed rate debt varies with changes in the market rate of interest, we enter into swap agreements 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 our fixed rate debt due to market rate changes.

We monitor our mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time may alter that mix by, for example, refinancing balances outstanding under our 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, we attempt to maintain an overall target mix of approximately 50% fixed rate debt and 50% variable rate debt.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 13 to our consolidated financial statements included elsewhere in this report.

Item 8. *Financial Statements and Supplementary Data.*

The information required in this Item 8 is included in this report as set forth in the "Index to Financial Statements" on page 109.

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, 2012, 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 evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012, 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 Tennessee Gas Pipeline Company, L.L.C. (TGP) from KMI effective August 1, 2012. TGP was acquired by KMI as part of KMI's acquisition of El Paso Corporation on May 25, 2012. TGP owns the Tennessee Gas natural gas pipeline system, and we excluded this business from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2012. TGP constituted 7% of our total revenues for 2012 and 25% of our total assets as of December 31, 2012.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2012 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*

Directors and Executive Officers of our General Partner and its Delegate

Set forth below is information concerning the directors and executive officers of our general partner and KMR, the delegate of our general partner. All directors of our general partner are elected annually by, and may be removed by, Kinder Morgan (Delaware), Inc. as its sole common shareholder, and all directors of KMR are elected annually by, and may be removed by, our general partner as the sole holder of KMR's voting shares. All officers of our general partner and all officers of KMR serve at the discretion of the board of directors of our general partner.

Name	Age	Position with our General Partner and KMR
Richard D. Kinder	68	Director, Chairman and Chief Executive Officer
C. Park Shaper	44	Director and President
Steven J. Kean	51	Executive Vice President and Chief Operating Officer
Ted A. Gardner	55	Director
Gary L. Hultquist	69	Director
Perry M. Waughtal	77	Director
Kimberly A. Dang	43	Vice President and Chief Financial Officer
Jeffrey R. Armstrong	44	Vice President (President, Terminals)
Thomas A. Bannigan	59	Vice President (President, Products Pipelines)
Richard T. Bradley	57	Vice President (President, CO_2)
David D. Kinder	38	Vice President, Corporate Development and Treasurer
Joseph Listengart	44	Vice President, General Counsel and Secretary
Thomas A. Martin	51	Vice President (President, Natural Gas Pipelines)
James E. Street	56	Vice President, Human Resources and Administration

Richard D. Kinder is Director, Chairman and Chief Executive Officer of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Kinder has served as Director, Chairman and Chief Executive Officer of KMR since its formation in February 2001. He was elected Director, Chairman and Chief Executive Officer of KMI in October 1999. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. in February 1997. He also served as Chief Manager, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Chairman and Chief Executive Officer of KMI upon its conversion. In May 2012, he was elected as a Director, Chairman and appointed as Chief Executive Officer of the general partner of El Paso Pipeline Partners, L.P. Mr. Kinder is the uncle of David Kinder, Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc., KMI and the general partner of El Paso Pipeline Partners, L.P. Mr. Kinder's experience as Chief Executive Officer of KMI, KMR, Kinder Morgan G.P., Inc. and the general partner of El Paso Pipeline Partners, L.P., provide him with a familiarity with our strategy, operations and finances that can be matched by no one else. In addition, we believe that with Mr. Kinder's significant direct and indirect equity ownership in us, his economic interests are aligned with those of our other equity investors.

C. Park Shaper is Director and President of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Shaper was elected President of KMR, Kinder Morgan G.P., Inc. and KMI in May 2005. Mr. Shaper was elected Director of KMR and Kinder Morgan G.P., Inc. in January 2003. He also served as President, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Director and President of KMI upon its conversion. He has served in various management roles for the Kinder Morgan companies since 2000. In May 2012, he was elected as a director and appointed as President of the general partner of El Paso Pipeline Partners, L.P. He received a Masters of Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University. Mr. Shaper also has a Bachelor of Science degree in Industrial Engineering and a Bachelor of Arts degree in Quantitative Economics from Stanford University. Mr. Shaper is also a trust manager of Weingarten Realty Investors. Mr. Shaper's experience as President of KMI, KMR, Kinder Morgan G.P., Inc. and the general partner of El Paso Pipeline Partners, L.P., and as an executive officer of various Kinder Morgan entities, provides him valuable management and operational expertise and intimate knowledge of our business operations, finances and strategy.

Steven J. Kean is Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Kean was elected Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc. and KMI in January 2006. He also served as President, Natural Gas Pipelines of KMR and Kinder Morgan G.P., Inc. from July 2008 to November 2009. He also served as Chief Operating Officer, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Director, Executive Vice President and Chief Operating Officer of KMI upon its conversion. He has served in various management roles for the Kinder Morgan companies since 2002. In May 2012, he was elected as a director and appointed as Executive Vice President and Chief Operating Officer of the general partner of El Paso Pipeline Partners, L.P. Mr. Kean received his Juris Doctor from the University of Iowa in May 1985 and received a Bachelor of Arts degree from Iowa State University in May 1982.

Ted A. Gardner is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Gardner was elected Director of KMR and Kinder Morgan G.P., Inc. in July 2011 to fill the vacancy left by Mr. C. Berdon Lawrence, who resigned from the KMR and Kinder Morgan G.P., Inc. boards of directors that same month. Since June 2005, Mr. Gardner has been a Managing Partner of Silverhawk Capital Partners in Charlotte, North Carolina. Formerly, he was a Director of KMI from 1999 to 2007, and was a Director of Encore Acquisition Company from 2001 to 2010. Mr. Gardner also served as Managing Partner of Wachovia Capital Partners and was a Senior Vice President of Wachovia Corporation from 1990 to June 2003. He is currently a Director of Summit Materials Holdings and Spartan Energy Partners. We believe Mr. Gardner's prior management, business and leadership experience, and his previous board experience with KMI, provides us with the perspectives and judgment necessary to guide our business strategies, thereby qualifying him to serve as a director.

Gary L. Hultquist is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Hultquist was elected Director of KMR upon its formation in February 2001. He was elected Director of Kinder Morgan G.P., Inc. in October 1999. Since 1995, Mr. Hultquist has been the Managing Director of Hultquist Capital, LLC, a San Francisco-based strategic and merger advisory firm. Since 2009, Mr. Hultquist has also been Chairman of the board of directors of Prairie Bankers, LLC, a data center development company, and a Principal of NewCap Partners Inc., a FINRA-registered broker-dealer and investment bank, specializing in technology, mergers and acquisitions. Mr. Hultquist has over 20 years of experience as an investment banker and over 15 years experience practicing law. This combination of experience provides him an understanding of the business and legal risks applicable to us.

Perry M. Waughtal is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Waughtal was elected Director of KMR upon its formation in February 2001. Mr. Waughtal was elected Director of Kinder Morgan G.P., Inc. in April 2000. Since 1994, Mr. Waughtal has been the Chairman of Songy Partners Limited, an Atlanta, Georgia based real estate investment company. Mr. Waughtal was a Director of HealthTronics, Inc. from 2004 to 2009. We believe Mr. Waughtal's 30 years of experience with Hines Interests Limited Partnership, a privately owned, international real estate firm, including as Vice Chairman of development and operations and Chief Financial Officer, and 15 years of experience as Chairman of Songy Partners Limited provide him with planning, management, finance and accounting experience with, and an understanding of, large organizations with capital-intensive projects analogous to the types in which we typically engage, thereby qualifying him to serve as a director.

Kimberly A. Dang is Vice President and Chief Financial Officer of KMR, Kinder Morgan G.P., Inc., and KMI. Mrs. Dang was elected Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and KMI in May 2005. She was elected Vice President, Investor Relations of KMR, Kinder Morgan G.P., Inc. and KMI in July 2002 and served in that role until January 2009. She also served as Chief Financial Officer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President and Chief Financial Officer of KMI upon its conversion. She has served in various management roles for the Kinder Morgan companies since 2001. In May 2012, she was appointed as Vice President and Chief Financial Officer of the general partner of El Paso Pipeline Partners, L.P. Mrs. Dang received a Masters in Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University and a Bachelor of Business Administration degree in accounting from Texas A&M University.

Jeffrey R. Armstrong is Vice President (President, Terminals) of KMR and Kinder Morgan G.P., Inc. Mr. Armstrong became Vice President (President, Terminals) in July 2003. He served as President, Kinder Morgan Liquids Terminals LLC from March 1, 2001, when the company was formed via the acquisition of GATX Terminals, through July 2003. From 1994 to 2001, Mr. Armstrong worked for GATX Terminals, where he was General Manager of their East Coast operations. He received his Bachelor's degree from the United States Merchant Marine Academy and an MBA from the University of Notre Dame.

Thomas A. Bannigan is Vice President (President, Products Pipelines) of KMR and Kinder Morgan G.P., Inc. and President and Chief Executive Officer of Plantation Pipe Line Company. Mr. Bannigan was elected Vice President (President, Products Pipelines) of KMR upon its formation in February 2001. He was elected Vice President (President, Products Pipelines) of Kinder Morgan G.P., Inc. in October 1999. Mr. Bannigan has served as President and Chief Executive Officer of Plantation

Pipe Line Company since May 1998. Mr. Bannigan received his Juris Doctor, cum laude, from Loyola University in 1980 and received a Bachelors degree from the State University of New York in Buffalo.

Richard T. Bradley is Vice President (President, CO_2) of KMR and of Kinder Morgan G.P., Inc. and President of Kinder Morgan CO_2 Company, L.P. Mr. Bradley was elected Vice President (President, CO_2) of KMR upon its formation in February 2001 and Vice President (President, CO_2) of Kinder Morgan G.P., Inc. in April 2000. Mr. Bradley has been President of Kinder Morgan CO_2 Company, L.P. (formerly known as Shell CO_2 Company, Ltd.) since March 1998. Mr. Bradley received a Bachelor of Science in Petroleum Engineering from the University of Missouri at Rolla.

David D. Kinder is Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Kinder was elected Treasurer of KMR, Kinder Morgan G.P., Inc. and KMI in May 2005. He was elected Vice President, Corporate Development of KMR, Kinder Morgan G.P., Inc. and KMI in October 2002 and has served in various management roles for the Kinder Morgan companies since 2000. He also served as Treasurer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President, Corporate Development and Treasurer of KMI upon its conversion. In May 2012, he was appointed as Vice President, Corporate Development and Treasurer of the general partner of El Paso Pipeline Partners, L.P. Mr. Kinder graduated cum laude with a Bachelors degree in Finance from Texas Christian University in 1996. Mr. Kinder is the nephew of Richard D. Kinder.

Joseph Listengart is Vice President, General Counsel and Secretary of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Listengart was elected Vice President, General Counsel and Secretary of KMR upon its formation in February 2001. He was elected Vice President and General Counsel of Kinder Morgan G.P., Inc. and Vice President, General Counsel and Secretary of KMI in October 1999 and has been an employee of Kinder Morgan G.P., Inc. since March 1998. He also served as General Counsel and Secretary of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President, General Counsel and Secretary of KMI upon its conversion. In May 2012, he was appointed as Vice President, General Counsel and Secretary of the general partner of El Paso Pipeline Partners, L.P. Mr. Listengart received his Masters in Business Administration from Boston University in January 1995, his Juris Doctor, magna cum laude, from Boston University in May 1994, and his Bachelor of Arts degree in Economics from Stanford University in June 1990.

Thomas A. Martin is Vice President (President, Natural Gas Pipelines) of KMR, Kinder Morgan G.P., Inc and KMI. Mr. Martin was elected Vice President (President, Natural Gas Pipelines) of KMR and Kinder Morgan G.P., Inc. in November 2009 and was elected Vice President (President, Natural Gas Pipelines) of KMI in 2012. Mr. Martin served as President, Texas Intrastate Pipeline Group from May 2005 until November 2009 has served in various management roles for the Kinder Morgan companies since 2003. In May 2012, he was elected as a director and appointed as Vice President (President, Natural Gas Pipelines) of the general partner of El Paso Pipeline Partners, L.P. Mr. Martin received a Bachelor of Business Administration degree from Texas A&M University.

James E. Street is Vice President, Human Resources and Administration of KMR, Kinder Morgan G.P., Inc., and KMI. Mr. Street was elected Vice President, Human Resources and Administration of KMR upon its formation in February 2001. He was elected Vice President, Human Resources and Administration of Kinder Morgan G.P., Inc. and KMI in August 1999. He has been Vice President, Human Resources and Administration of KMI since February 2011. In May 2012, he was appointed as Vice President, Human Resources and Administration of the general partner of El Paso Pipeline Partners, L.P. Mr. Street received a Masters of Business Administration degree from the University of Nebraska at Omaha and a Bachelor of Science degree from the University of Nebraska at Kearney.

Organizational Changes

We announced on January 16, 2013 a number of management changes at KMR and our general partner, which will be substantially completed by March 31, 2013. Included in the previously announced management changes are the following:

- C. Park Shaper will be retiring as Director and President effective March 31, 2013, but will remain a member of KMI’s board. At such time, Steven J. Kean will be elected as Director, President and Chief Operating Officer;

- Jeffrey R. Armstrong will be retiring as Vice President (President, Terminals) and will become Vice President of Corporate Strategy. At such time, John Schlosser will be elected Vice President (President, Terminals);

- Thomas A. Bannigan will be retiring as Vice President (President, Products Pipelines). At such time, Ron McClain will be elected Vice President (President, Products Pipelines);

- Richard T. Bradley will be retiring as Vice President (President, CO2). At such time, Jim Wuerth will be elected Vice President (President, President, CO2);

- David D. Kinder will be retiring as Vice President, Corporate Development and Treasurer. At such time, Dax Sanders will be elected Vice President, Corporate Development; and

- Joseph Listengart will be retiring as Vice President and General Counsel and Secretary, but will continue working for the company, assisting as needed on significant transactions and other matters. At such time, David DeVeau will be elected Vice President and General Counsel.

John W. Schlosser, 49, is Vice President (President, Terminals) Elect of KMR and Kinder Morgan G.P., Inc. Mr. Schlosser was elected Vice President (President, Terminals) of KMR and Kinder Morgan G.P., Inc. in January 2013, such election to be effective in March 2013. Mr. Schlosser was named Senior Vice President and Chief Commercial Officer of Kinder Morgan's Terminals group in 2010, and previously served as Vice President of Sales and Business Development for Kinder Morgan's Terminals group since he joined Kinder Morgan in 2001 in connection with Kinder Morgan's purchase of the U.S. pipeline and terminal assets of the GATX Corporation, where he served as Vice President of Sales. Mr. Schlosser has more than 27 years of experience in commodity transportation and logistics, business development and sales, sales management and operations. Mr. Schlosser holds a Bachelor of Science degree from Miami University, Oxford, Ohio.

Ronald G. McClain, 60, is Vice President (President, Products Pipelines) Elect of KMR and Kinder Morgan G.P., Inc. Mr. McClain was elected Vice President (President, Products Pipelines) of KMR and Kinder Morgan G.P., Inc. in January 2013, such election to be effective in March 2013. Since 2005, Mr. McClain has served as Vice President of operations and engineering for Kinder Morgan's Products Pipelines group. Mr. McClain joined Kinder Morgan over 30 years ago and, prior to 2005, held various operations and engineering positions in Kinder Morgan's Products Pipelines and Natural Gas Pipelines groups. Mr. McClain holds a bachelor's degree in computer science from Aurora University.

James P. Wuerth, 56, is Vice President (President, CO2) Elect of KMR and Kinder Morgan G.P., Inc. Mr. Wuerth was elected Vice President (President, CO2) of KMR and Kinder Morgan G.P., Inc. in January 2013, such election to be effective in March 2013. Mr. Wuerth has served as Vice President of Finance and Accounting for Kinder Morgan's CO2 segment since joining Kinder Morgan in 2000. He has more than 30 years of oil and gas industry experience in accounting, operations, field development and business development. Prior to joining Kinder Morgan, he worked for Shell Oil Company. Mr. Wuerth holds a bachelor's degree in accounting from the University of Washington in Seattle and is a Certified Public Accountant in the State of Texas.

Dax A. Sanders, 37, is Vice President Elect, Corporate Development of KMR, Kinder Morgan G.P., Inc., KMI and El Paso Pipeline GP Company, L.L.C. Mr. Sanders was elected Vice President, Corporate Development of KMR and Kinder Morgan G.P., Inc. in January 2013, such election to be effective in March 2013. Mr. Sanders is currently a Vice President within Kinder Morgan's Corporate Development group, where he has served since 2009. From 2006 until 2009, Mr. Sanders was Vice President of Finance for Kinder Morgan Canada. Mr. Sanders joined Kinder Morgan in 2000, and from 2000 to 2006 served in various finance and business development roles within the Corporate Development, Investor Relations, Gas and Products groups, with the exception of a two-year period while he attended business school. Mr. Sanders holds a master's degree in business administration from the Harvard Business School and a master's and a bachelor's degree in accounting from Texas A&M University. He is also a Certified Public Accountant in the State of Texas.

David R. DeVeau, 47, is Vice President and General Counsel Elect of KMR, Kinder Morgan G.P., Inc., KMI and El Paso Pipeline GP Company, L.L.C. Mr. DeVeau was elected Vice President and General Counsel of KMR and Kinder Morgan G.P., Inc. in January 2013, such election to be effective in Mach 2013. Mr. DeVeau joined Kinder Morgan in 2001 and has served as Deputy General Counsel since 2006. Mr. DeVeau received a J.D. degree from The Dickinson School of Law, Pennsylvania State University, and a bachelor's degree, cum laude, in political science from Norwich University.

Corporate Governance

We have a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 comprised of Messrs. Gardner, Hultquist and Waughtal. Mr. Waughtal is the chairman of the audit committee and has been determined by the board to be an "audit committee financial expert." The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

We have not, nor has our general partner nor KMR, made, within the preceding three years, contributions to any tax-exempt organization in which any of our or KMR's independent directors serves as an executive officer that in any single fiscal year exceeded the greater of $1.0 million or 2% of such tax-exempt organization's consolidated gross revenues.

We make available free of charge within the "Investors" information section of our Internet website, at www.kindermorgan.com, the governance guidelines, the charters of the audit committee, compensation committee and nominating and governance committee, and our code of business conduct and ethics (which applies to senior financial and accounting officers and the chief executive officer, among others). We intend to disclose any amendments to our code of business conduct and ethics that would otherwise be disclosed on Form 8-K and any waiver from a provision of that code granted to our executive officers or directors that would otherwise be disclosed on Form 8-K on our website within four business days following such amendment or waiver. The information contained on or connected to our 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.

Interested parties may contact our lead director (Mr. Waughtal, discussed in Item 13), the chairpersons of any of the board's committees, the independent directors as a group or the full board by mail to Kinder Morgan Management, LLC, 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the "Contact Us" section of our Internet website, at www.kindermorgan.com. Any communication should specify the intended recipient.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934 requires our directors and officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the Securities and Exchange Commission. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2012.

Item 11. *Executive Compensation.*

As is commonly the case for publicly traded limited partnerships, we have no officers. Under our limited partnership agreement, Kinder Morgan G.P., Inc., as our general partner, is to direct, control and manage all of our activities. Pursuant to a delegation of control agreement, Kinder Morgan G.P., Inc. has delegated to KMR the management and control of our business and affairs to the maximum extent permitted by our partnership agreement and Delaware law, subject to our general partner's right to approve certain actions by KMR. The executive officers and directors of Kinder Morgan G.P., Inc. serve in the same capacities for KMR, and certain of those executive officers also serve as executive officers of KMI.

Except as indicated otherwise, all information in this report with respect to compensation of executive officers describes the total compensation received by those persons in all capacities for services rendered to us, our subsidiaries and our affiliates, including KMI. In this Item 11, "we," "our" or "us" refers to Kinder Morgan Energy Partners, L.P. and, where appropriate, Kinder Morgan G.P., Inc., KMR, and KMI.

Compensation Discussion and Analysis

Program Objectives

We seek to attract and retain executives who will help us achieve our primary business strategy objective of growing the value of our portfolio of businesses for the benefit of our unitholders. To help accomplish this goal, we have designed an executive compensation program that rewards individuals with competitive compensation that consists of a mix of cash, benefit plans and long-term compensation, with a majority of executive compensation tied to the "at-risk" portions of the annual cash bonus.

The key objectives of our executive compensation program are to attract, motivate and retain executives who will advance our overall business strategies and objectives to create and return value to our unitholders. We believe that an effective executive compensation program should link total compensation to financial performance and to the attainment of short-term and long-term strategic, operational, and financial objectives. We believe operational objectives should take into account adherence to and promotion of our Code of Business Conduct and Ethics and our Environmental Health and Safety Policy

Statement. We also believe it should provide competitive total compensation opportunities at a reasonable cost. In designing our executive compensation program, we have recognized that our executives have a much greater portion of their overall compensation at-risk than do our other employees. Consequently, we have tried to establish the at-risk portions of our executives' total compensation at levels that recognize their much increased level of responsibility and their ability to influence business results.

Since 2007, our executive compensation program has been principally composed of the following two elements: (i) base cash salary; and (ii) possible annual cash bonus (reflected in the Summary Compensation Table below as Non-Equity Incentive Plan Compensation). From 2010 through 2012, our executives' annual base cash salary did not exceed $300,000, which we believe was below annual base salaries for comparable positions in the marketplace during that time period.

In addition, we believe that the compensation of our Chief Executive Officer, Chief Financial Officer and the other executives named in the Summary Compensation Table below (collectively referred to in this Item 11 as our named executive officers), should be directly and materially tied to the financial performance of KMI and us, and should be aligned with the interests of our unitholders. Therefore, the majority of our named executive officers' compensation is allocated to the "at-risk" portion of our compensation program—the annual cash bonus. Accordingly, for 2012, our executive compensation was weighted toward the cash bonus, payable on the basis of the achievement of (i) a dividend per share target by KMI; and (ii) a cash distribution per common unit target by us.

Our compensation is determined independently without the use of any compensation consultants. Nevertheless, we annually compare our executive compensation components with market information, consisting of third-party surveys in which we participate. The surveys we use in reviewing our executive compensation consist of the following: (i) Towers Watson Executive Survey, in which over 400 companies participate and (ii) the Aon Hewitt Executive Survey, in which approximately 300 to 400 companies participate. The purpose of this comparison is to ensure that our total compensation package operates effectively, remains both reasonable and competitive with the energy industry, and is generally comparable to the compensation offered by companies of similar size and scope as us. We also keep abreast of current trends, developments, and emerging issues in executive compensation, and if appropriate, will obtain advice and assistance from outside legal, compensation or other advisors.

We have endeavored to design our executive compensation program and practices with appropriate consideration of all tax, accounting, legal and regulatory requirements. Section 162(m) of the Internal Revenue Code limits the deductibility of certain compensation for executive officers to $1,000,000 of compensation per year; however, if specified conditions are met, certain compensation may be excluded from consideration of the $1,000,000 limit. Since the bonuses paid to our executive officers were paid under KMI's Annual Incentive Plan as a result of reaching designated financial targets established by KMI's and KMR's compensation committee, we expect that all compensation paid to our executives would qualify for deductibility under federal income tax rules. Though we are advised that limited partnerships, such as us, are not subject to section 162(m), we have chosen to generally operate as if this code section does apply to us as a measure of appropriate governance.

In January 2013, the Compensation Committee increased the annual base salary cap for our executive officers from $300,000 to $400,000, other than our Chairman and Chief Executive who receives $1 of base salary per year. However, we expect to only increase our executives' salaries to $325,000 for 2013 and we do not expect our executives' annual base salaries to reach the cap for a period of years. We continue to believe that even at the $400,000 cap our executive officers base salaries would be below annual base salaries for comparable positions in the marketplace. In addition, all of the long-term incentive compensation received in the Going Private Transaction discussed below in "Compensation Related to the Going Private Transaction" was converted into Class P shares of KMI and wound up in 2012. Accordingly, in 2013 we expect the Compensation Committee to support the granting of long-term incentive compensation in the form of restricted KMI stock to the named executives under KMI's 2011 Stock Incentive Plan. Any awards granted will be subject to a multi-year vesting schedule exceeding three years.

Behaviors Designed to Reward

Our executive compensation program is designed to reward individuals for advancing our business strategies and the interests of our stakeholders, and prohibits engaging in any detrimental activities, such as performing services for a competitor, disclosing confidential information or violating appropriate business conduct standards. Each executive is held accountable to uphold and comply with company guidelines, which require the individual to maintain a discrimination-free workplace, to comply with orders of regulatory bodies, and to maintain high standards of operating safety and environmental protection.

Unlike many companies, we have no executive perquisites, supplemental executive retirement, non-qualified supplemental defined benefit/contribution, deferred compensation or split-dollar life insurance programs for our executive officers. We have no executive company cars or executive car allowances nor do we pay for financial planning services. Additionally, we do not own any corporate aircraft, and we do not pay for executives to fly first class. We believe that this area of our overall compensation package is below competitive levels for comparable companies; however, we have no current plans to change our policy of not offering such executive benefits or perquisite programs.

We do not have employment agreements (other than with Richard D. Kinder) or change of control agreements with our executive officers. In connection with KMI's initial public offering in February 2011, one of our affiliated companies entered into severance agreements with eleven of our executive officers. See "—Other Compensation—Other Potential Post-Employment Benefits."

At his request, Richard D. Kinder receives $1 of base salary per year from KMI. Additionally, Mr. Kinder has requested that he receive no annual bonus or other compensation from us or any of our affiliates (other than the KMI Class B unit awards that he received in 2007 in connection with KMI's going-private transaction; see "Elements of Compensation-Compensation Related to the Going-Private Transaction"). Mr. Kinder does not have any deferred compensation, supplemental retirement or any other special benefit, compensation or perquisite arrangement with us, and each year, Mr. Kinder reimburses us for his portion of health care premiums and parking expenses.

Elements of Compensation

As outlined above, since 2007 our executive compensation program is principally composed of the following two elements: (i) a base cash salary; and (ii) a possible annual cash bonus. With respect to our named executive officers other than our Chief Executive Officer, KMR's compensation committee reviews and approves annually the financial goals and objectives of both us and KMI that are relevant to the compensation of our named executive officers.

The KMR compensation committee solicits information from Richard D. Kinder and James E. Street (Vice President, Human Resources and Administration), with respect to the performance of C. Park Shaper, President, and Steven J. Kean, Executive Vice President and Chief Operating Officer. Similarly, the compensation committee solicits information from Messrs. Kinder, Shaper, Kean and Street with respect to the performance of the other named executive officers. The compensation committee also obtains information from Mr. Street with respect to compensation of comparable positions of responsibility at comparable companies. All of this information is taken into account by the compensation committee, which makes final determinations regarding compensation of the named executive officers. No named executive officer reviews his or her own performance or approves his or her own compensation.

Furthermore, if any of our general partner's or KMR's executive officers is also an executive officer of KMI, the compensation determination or recommendation (i) may be with respect to the aggregate compensation to be received by such officer from KMI, KMR, and our general partner that is to be allocated among them; or alternatively (ii) may be with respect to the compensation to be received by such executive officers from KMI, KMR or our general partner, as the case may be, in which case such compensation will be allocated among KMI, on the one hand, and KMR and our general partner, on the other hand.

Base Salary

Base salary is paid in cash. The base salary cap for our executive officers, with the exception of our Chairman and Chief Executive Officer who receives $1 of base salary per year as described above, for each of the years 2010 through 2012 was an annual amount not to exceed $300,000. Generally, we believe that our executive officers' base salaries are below base salaries for executives in similar positions and with similar responsibilities at companies of comparable size and scope, based upon independent salary surveys in which we participate.

Possible Annual Cash Bonus (Non-Equity Cash Incentive)

For the 2010 bonus year, KMI's board of directors approved an Annual Incentive Plan, which became effective January 1, 2010. Commencing with bonus awards for the 2011 bonus year, KMI's board of directors approved a new Annual Incentive Plan (referred to in this discussion as the Annual Incentive Plan or the plan) that mirrored the previous plan. The overall purpose of the Annual Incentive Plan is to increase our executive officers' and our employees' personal stake in the continued success of KMI, and us, by providing to them additional incentives through the possible payment of annual cash bonuses. Under the plan, a budget amount is established for annual cash bonuses at the beginning of each year that may be paid to our executive officers and other employees depending on whether KMI and its subsidiaries (including us) meet certain financial performance objectives (as discussed below). The amount included in our budget for bonuses is not allocated between our executive officers and non-executive officers. Assuming the financial performance objectives are met, the budgeted pool of bonus dollars is further assessed and potentially increased if the financial performance objectives are exceeded. The budget for bonuses also may be adjusted upward or downward based on KMI's and its subsidiaries' overall performance in other areas, including but not limited to safety and environmental goals and regulatory compliance.

All of KMI's employees and the employees of its subsidiaries, including KMGP Services Company, Inc., are eligible to participate in the plan, except employees who are included in a unit of employees covered by a collective bargaining agreement unless such agreement expressly provides for eligibility under the plan. However, only eligible employees who are selected by KMR's compensation committee will actually participate in the plan and receive bonuses.

The plan consists of two components: the executive plan component and the non-executive plan component. Our Chairman and Chief Executive Officer, and all employees who report directly to the Chairman, including all of the named executive officers, are eligible for the executive plan component; however, as stated elsewhere in this "Compensation Discussion and Analysis," Richard D. Kinder has elected to not participate under the plan. As of December 31, 2012, excluding Mr. Kinder, eleven of our executive officers were eligible to participate in the executive plan component. All other U.S. and Canadian eligible employees were eligible for the non-executive plan component.

At or before the start of each calendar year (or later, to the extent allowed under Internal Revenue Code regulations), financial performance objectives based on one or more of the criteria set forth in the plan are established by KMR's compensation committee. Two financial performance objectives were set for 2012 under both the executive plan component and the non-executive plan component. The two financial performance objectives were:

- $4.98 in cash distributions per common unit by us (the same as our previously disclosed 2012 budget expectations); and

- $1.35 in cash dividends per share paid by KMI.

A third objective which could potentially decrease or increase the budgeted pool of bonus dollars for 2012 was a goal to achieve our environmental, health, and safety performance objectives, by (i) beating industry average incident rates; (ii) improving incident rates compared to our previous three year averages; and (iii) experiencing no significant incidents in our operations or expansions.

At the end of 2012, the extent to which the financial performance objectives have been attained and the extent to which the bonus opportunity has been earned under the formula previously established by KMR's compensation committee was determined. For 2012:

- we distributed $4.98 in cash per common unit—generating enough cash from operations in 2012 to fully cover our cash distribution target; but due to deteriorating natural gas liquids prices, slightly below our budgeted amounts; and

- KMI paid $1.40 in cash dividends per share.

Based on the above, the KMR compensation committee approved approximately 94% of the 2012 budgeted cash bonus opportunity be earned and funded under the plan. The executive funding level of 86% lowered the overall funding percentage. The approved funding level includes any premium pay calculations for bonus awards paid to non-exempt employees.

In addition to determining the financial performance objectives under the Annual Incentive Plan, at or before the start of each calendar year, the compensation committee sets the bonus opportunities available to each executive officer, see table "Grants of Plan-Based Awards." If neither of the financial performance objectives was met, no bonus opportunity would be available to the named executive officers. The maximum payout to any individual under the plan for any year is $3 million. The compensation committee may reduce the amount of the bonus actually paid to any executive officer from the amount of any bonus opportunity open to such executive officer. Because payments under the plan for our executive officers are determined by comparing actual performance to the performance objectives established each year for eligible executive officers chosen to participate for that year, it is not possible to accurately predict any amounts that will actually be paid under the executive portion of the plan over the life of the plan. The compensation committee set maximum bonus opportunities under the plan for 2012 for the executive officers at dollar amounts in excess of those which were expected to actually be paid under the plan. In fact, while achievement of the financial performance objectives sets the maximum bonus opportunity for each executive officer, the compensation committee has never awarded the maximum bonus opportunity to a current named executive officer. The actual payout amounts under the Annual Incentive Plan for 2012 (paid in 2013) are set forth in the Summary Compensation Table in the column entitled "Non-Equity Incentive Plan Compensation."

The 2012 bonuses for our executive officers were overwhelmingly based on whether the established financial performance objectives were met. The compensation committee also considered, in a purely subjective manner, how well the executive officer performed his or her duties during the year. Information was solicited from relevant members of senior management regarding the performance of our named executive officers (described following), and determinations and recommendations were made at the regularly scheduled first quarter board and compensation committee meetings held in January 2013. Other factors considered by the compensation committee primarily consisted of the amount of the bonus paid to the executive officer in the prior year and market data about compensation of comparable positions of responsibility at comparable companies, consisting of the compensation surveys referred to above. With respect to using these other factors in assessing performance, KMR's compensation committee did not find it practicable to, and did not, use a "score card" or quantify or assign relative weight to the specific criteria considered. The amount of a downward adjustment, subject to the maximum bonus opportunity that was established at the beginning of the year, was not subject to a formula. Specific aspects of an individual's performance were not identified in advance. Rather, adjustments were based on KMR's compensation committee's judgment, giving consideration to the totality of the record presented, including the individual's performance and the magnitude of any other positive or negative factors.

Upon the occurrence of a change in control, the compensation committee may take any action with respect to outstanding awards that it deems appropriate; and in the event that such action is to distribute an award, the award will be distributed in a lump sum no later than 30 days after the change in control. Under the plan, "change in control" means (i) that any person, other than a permitted holder (as defined below), becomes the beneficial owner of securities representing 50% or more of the voting power of KMI; (ii) a sale, merger or other business combination as a result of which transaction the voting securities of KMI, outstanding immediately before such transaction do not continue to represent at least 50% of the voting power of KMI after giving effect to such transaction; (iii) the sale or transfer of all or substantially all of the assets of KMI or one of its parent entities, including us, other than to an entity of which more than 50% of the voting power is held by permitted holders (as defined below); (iv) during any period of two consecutive years following the closing of KMI's initial public offering, individuals who were directors at the beginning of the period or whose election or nomination for election by KMI's stockholders was approved by a vote of two-thirds of the directors then still in office who had been directors at the beginning of the period or previously so approved, cease for any reason other than normal retirement, death or disability to constitute at least a majority of the board of directors then in office; or (v) the stockholders of KMI approve a plan of complete liquidation of KMI or an agreement for the sale or disposition by KMI of all or substantially all of its assets. Under the plan, a "permitted holder" means Richard D. Kinder and investment funds advised by or affiliated with Goldman, Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC.

If, in connection with a change in control, Richard D. Kinder is no longer our Chairman:

- each participant under the executive component of the plan will be deemed to have earned 100% of the bonus opportunity available to him or her, unless the compensation committee has previously determined that the participant should receive a lesser percentage of the bonus opportunity;

- each participant under the non-executive component of the plan will receive an award equal to the award most recently paid to such participant under the Annual Incentive Plan, or if no awards have been paid under the plan, an award equal to the most recent award paid to such participant under any prior Annual Incentive Plan; and

- the awards to executive and non-executive participants will be paid in a cash lump sum within 30 days after the change in control.

Compensation Related to the Going-Private Transaction

In connection with KMI's going-private transaction, members of our management were awarded Kinder Morgan Holdco LLC Class A-1 and Class B units. In accordance with generally accepted accounting principles, we are 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 do not have any obligation, nor did we pay any amounts related to these compensation expenses as all expenses were borne by 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." 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 "Total Partners' Capital" on our balance sheet. The awards and terms of the Class B units granted to members of our 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 sold their interests in KMI or converted their Class A shares into Class P shares of KMI. 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 KMI's initial public offering. As of December 26, 2012, all Class B shares and Class C shares had converted into Class P shares.

Other Compensation

Kinder Morgan Savings Plan. The Kinder Morgan Savings Plan is a defined contribution 401(k) plan. The Kinder Morgan savings plan permits eligible employees of KMI and those of KMGP Services Company, Inc., including the named executive officers, to contribute between 1% and 50% of base compensation, on a pre-tax or Roth 401(k) basis, into participant accounts. For more information on this plan, see Note 9 "Employee Benefits—Kinder Morgan Savings Plan" to our consolidated financial statements included elsewhere in this report.

Kinder Morgan Retirement Plan. Employees of KMI and KMGP Services Company, Inc., including the named executive officers, are also eligible to participate in the Kinder Morgan Retirement Plan ("Plan"), a cash balance plan. Employees accrue benefits through a Personal Retirement Account ("PRA") in the Plan. Prior to 2013, KMI allocated contribution credits equivalent to 3% of eligible compensation every pay period to participants' PRA. Beginning January 1, 2013, KMI began allocating contribution credits of 4% or 5% of eligible compensation every pay period to participants' PRA based on age and years of eligible service as of December 31 of the prior year. For plan years prior to 2011, interest was credited to the PRA at the 30-year U.S. Treasury bond rate published in the Internal Revenue Bulletin for the November of the prior year. Beginning January 1, 2011, interest was credited to the PRA at the 5-year U.S. Treasury bond rate published in the Internal Revenue Bulletin for the November of the prior year, plus 0.25%. Employees become 100% vested in the plan after three years and may take a lump sum distribution upon termination of employment or retirement.

The following table sets forth the estimated actuarial present value of each named executive officer's accumulated pension benefit as of December 31, 2012, under the provisions of the Cash Balance Retirement Plan. With respect to our named executive officers, the benefits were computed using the same assumptions used for financial statement purposes, assuming current remuneration levels without any salary projection, and assuming participation until normal retirement at age 65. These benefits are subject to federal and state income taxes, where applicable, but are not subject to deduction for social security or other offset amounts.

Cash Balance Plan Pension Benefits

Name	Current Credited Yrs of Service	Present Value of Accumulated Benefit (a)	Contributions During 2012
Richard D. Kinder	12	$ —	$ —
Kimberly A. Dang	11	70,030	8,270
Steven J. Kean	11	82,098	8,409
Thomas A. Martin	10	67,803	8,244
C. Park Shaper	12	93,049	8,535

(a) The present values in the Pension Benefits table are current year-end balances.

Contingent Payment Obligations Under Shareholders Agreement. KMI has certain contingent payment obligations under the terms of its shareholders agreement that may be considered compensation to former holders of Class B shares and Class C shares, including the agreement to pay certain tax compliance expenses for a former holder of Class B shares or Class C shares in certain events related to such holder's ownership of Class B shares or Class C shares.

Potential Payments Upon Termination or Change-in-Control. Our named executive officers (excluding Richard D. Kinder) are entitled to certain benefits in the event their employment is terminated by KMI without cause or by them with good reason, whether or not related to a change in control. See "—Other Potential Post-Employment Benefits—Severance Agreements" below for a description of the terms. Mr. Kinder is also entitled to certain benefits under his employment agreement upon his termination by KMI without cause or by him with good reason, whether or not related to a change in control. See "Other Potential Post-Employment Benefits—Employment Agreement" below for a description of the terms.

The following tables list separately the potential payments and benefits upon a change in control of KMI and upon a termination of employment for our named executive officers. The tables assume the triggering event for the payments or provision of benefits occurred on December 31, 2012. Actual amounts payable to each executive listed below can only be determined definitively at the time of each executive's actual departure. In addition to the amounts shown in the tables below, each executive would receive payments for amounts of base salary and vacation time accrued through the date of termination and payment for any reimbursable business expenses incurred prior to the date of termination.

Potential Payments Upon Termination of Employment or Change in Control for Richard D. Kinder

	Termination Payment	Benefit Continuation
Termination without "cause" or "good reason" or due to "change in duties"(a)(c)	$ 2,250,000	$ 36,407
Termination due to death or "disability"(a)(b)	750,000	—
Upon a change in control	N/A	N/A

N/A - not applicable

(a) As such terms are defined in Mr. Kinder's employment agreement and described under "—Other Potential Post-Employment Benefits—Employment Agreement."

(b) If Mr. Kinder becomes disabled, he is eligible for the same medical benefits as most other employees.

Potential Payments Upon Termination of Employment or Change in Control for Other Named Executive Officers

	Termination Without Cause or Good Reason	
Name	**Salary Continuation**	**Benefit Continuation**
Kimberly A. Dang	$ 300,000	$ 14,345
Steven J. Kean	300,000	14,000
Thomas A. Martin	300,000	14,000
C. Park Shaper	600,000	29,568

Other Potential Post-Employment Benefits

Employment Agreement. On October 7, 1999, Mr. Kinder entered into an employment agreement with KMI pursuant to which he agreed to serve as its Chairman and Chief Executive Officer. His employment agreement provides for a term of three years and one year extensions on each anniversary of October 7th. Mr. Kinder, at his initiative, accepted an annual salary of $1 to demonstrate his belief in our long-term viability. Mr. Kinder continues to accept an annual salary of $1, and he receives no other compensation from us.

We believe that Mr. Kinder's employment agreement contains provisions that are beneficial to us and accordingly, Mr. Kinder's employment agreement is extended annually at the request of KMI's and KMR's boards of directors. For example, with limited exceptions, Mr. Kinder is prevented from competing in any manner with KMI or any of its subsidiaries, while he is employed by KMI and for 12 months following the termination of his employment with KMI. The employment agreement provides that he will receive a severance payment equal to $2.25 million in the event his employment is terminated without "cause" or in the event he is subject to a "change in duties" without his consent. His employment agreement also provides that in the event of his death or termination due to his total and permanent disability, he or his estate will receive an amount equal to the greater of his annual salary ($1) or $750,000, and in the case of his total and permanent disability, such amount will be an annual amount until the effective date of termination of employment. In addition, under the terms of KMI's shareholders agreement, Mr. Kinder also has agreed not to compete with KMI or any of its subsidiaries for an additional period of one year and not to solicit KMI's or any of its subsidiaries' employees or interfere with certain of its business relationships during the term of his employment and for two years thereafter.

Upon a change in control and a termination of Mr. Kinder's employment by KMI or by Mr. Kinder, certain payments made to him could be subject to the excise tax imposed on "excess parachute payments" by the Internal Revenue Code. Pursuant to his employment agreement, Mr. Kinder is entitled to have his compensation "grossed up" for all such excise taxes and any federal, state and local taxes applicable to such gross-up payment (including any penalties and interest). We estimate the amount of such gross up payment for Mr. Kinder's termination payment and benefits to be approximately $1.17 million. The estimate of "excess parachute payments" for purposes of these calculations does not take into account any mitigation for payments which could be shown (under the facts and circumstances) not to be contingent on a change in control or for any payments being made in consideration of non-competition agreements or as reasonable compensation. The gross-up calculations assume an excise tax rate of 20%, a statutory federal income tax rate of 39.6%, and a Medicare tax rate of 1.45%.

Under the employment agreement, "cause" means (i) a grand jury indictment or prosecutorial information charging Mr. Kinder with illegal or fraudulent acts, criminal conduct or willful misconduct; (ii) a grand jury indictment or prosecutorial information charging Mr. Kinder with any criminal acts involving moral turpitude; (iii) grossly negligent failure by Mr. Kinder to perform his duties in a manner which he has reason to know is in KMI's best interest; (iv) bad faith refusal by Mr. Kinder to carry out reasonable instructions of the board of directors of KMI's; and (v) a material violation by Mr. Kinder of any of the terms of the employment agreement.

Under the employment agreement, "change in duties" means, without Mr. Kinder's written consent, any of the following (i) a significant reduction in the nature, scope of authority or duties of Mr. Kinder; (ii) a substantial reduction in Mr. Kinder's existing annual base salary or bonus opportunity; (iii) receipt of employee benefits by Mr. Kinder that are materially inconsistent with the employee benefits provided by KMI to executives with comparable duties; or (iv) a change of more than 50 miles in the location of Mr. Kinder's principal place of employment.

Severance Agreements. In connection with KMI's initial public offering, a subsidiary of KMI entered into severance agreements eleven of our executive officers (including our named executive officers other than Richard D. Kinder) that provide severance in the amount of the executive's salary plus benefits during the executive's non-compete period, ranging from one to two years following the executive's termination of employment, if the executive voluntarily terminates his or her employment for "good reason" or the executive's employment with KMI and its subsidiaries is terminated "without cause." Other employees who did not enter into severance agreements with KMI are eligible for the same severance as all regular full time U.S.-based employees not covered by a bargaining agreement, which caps severance payments at an amount equal to six months of salary.

Under the severance agreements, "cause" means any of the following (i) conviction of a felony; (ii) commission of fraud or embezzlement against us or any of our subsidiaries; (iii) gross neglect of, or gross or willful misconduct in connection with the performance of, duties that is not cured within 30 days after written notice; (iv) willful failure or refusal to carry out reasonable and lawful instructions of the Chief Executive Officer or the board of directors that is not cured within 30 days after written notice; (v) failure to perform duties and responsibilities as the individual's primary business activity; (vi) judicial determination that the individual breached fiduciary duties; (vii) willful and material breach of the shareholders agreement, certificate of incorporation or bylaws that is not cured within 30 days after written notice; or (viii) material breach of a non-compete provision in the case of specified officers that is not cured with 30 days after written notice.

Under the shareholders agreement, "good reason" occurs when one of the following events occurs without an employee's consent, such employee provides written notice, such event is not corrected after such notice and the employee resigns (i) material diminution in the employee's duties and responsibilities; (ii) material reduction in the employee's annual base salary or aggregate benefits; (iii) material reduction in the employee's bonus opportunity; (iv) relocation of the employee's primary place of employment by more than 50 miles; or (v) willful and intentional breach of the shareholders agreement by us that has a material and adverse effect on the employee.

Summary Compensation Table

The following table shows compensation paid or otherwise awarded to (i) our principal executive officer; (ii) our principal financial officer; and (iii) our three most highly compensated executive officers (other than our principal executive officer and principal financial officer) serving at fiscal year end 2012 (collectively referred to as the "named executive officers") for services rendered to us, our subsidiaries or our affiliates, including KMI (collectively referred to as the KMI affiliated entities), during fiscal years 2012, 2011 and 2010, as applicable. The amounts in the columns below represent the total compensation paid or awarded to the named executive officers by all the KMI affiliated entities, and as a result, the amounts are in excess of the compensation expense allocated to, recognized and paid by us for services rendered to us.

Name and Principal Position	Year	Salary	(a) Bonus	(b) Non-Equity Incentive Plan Compensation	(c) Change in Pension Value	(d) All Other Compensation	Total
Richard D. Kinder Director,	2012	$ 1	$ —	$ —	$ —	$ —	$ 1
Chairman and Chief Executive	2011	1	—	—	—	—	1
Officer	2010	1	—	—	—	—	1
Kimberly A. Dang Vice President	2012	300,000	600,000	800,000	8,270	14,205	1,722,475
and Chief Financial Officer	2011	300,000	175,000	625,000	8,280	13,330	1,121,610
	2010	294,444	—	500,000	9,544	11,704	815,692
Steven J. Kean Executive Vice	2012	300,000	600,000	1,200,000	8,409	15,063	2,123,472
President and Chief Operating	2011	300,000	—	1,250,000	8,469	15,028	1,573,497
Officer	2010	294,444	—	1,000,000	10,058	13,247	1,317,749
Thomas A. Martin, Vice President	2012	300,000	600,000	850,000	8,244	14,018	1,772,262
and President Natural Gas	2011	—	—	—	—	—	—
Pipelines (e)	2010	—	—	—	—	—	—
C. Park Shaper Director and	2012	300,000	600,000	1,250,000	8,535	14,205	2,172,740
President	2011	300,000	250,000	1,300,000	8,641	14,170	1,872,811
	2010	294,444	—	1,040,000	10,524	12,925	1,357,893

(a) Represents bonus payments awarded and paid by KMI to the executive officers in connection with their efforts in KMI's February 2011 initial public offering and in 2012 for their efforts associated with the 2012 EP acquisition.

(b) Represents amounts paid according to the provisions of the Annual Incentive Plan then in effect. Amounts were earned in the fiscal year indicated but were paid in the next fiscal year.

(c) Represents the 2012, 2011 and 2010, as applicable, change in the actuarial present value of accumulated defined pension benefit (including unvested benefits) according to the provisions of KMI's Cash Balance Retirement Plan.

(d) Amounts include value of contributions to the KMI Savings Plan (a 401(k) plan), value of group-term life insurance exceeding $50,000, and taxable parking subsidy. Amounts in 2012, 2011 and 2010 representing the value of contributions to the KMI Savings Plan are $12,500, $12,250 and $11,022, respectively.

(e) Mr. Martin was not a named executive officer during years 2010 or 2011.

Grants of Plan-Based Awards

The following supplemental compensation table shows compensation details on the value of all non-guaranteed and non-discretionary incentive awards granted during 2012 to our named executive officers. The table includes awards made during or for 2012. The information in the table under the caption "Estimated Future Payouts Annual Incentive Plan Awards" represents the threshold, target and maximum amounts payable under the Kinder Morgan, Inc. Annual Incentive Plan for performance in 2012. Amounts actually paid under that plan for 2012 are set forth in the Summary Compensation Table under the caption "Non-Equity Incentive Plan Compensation."

	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(a)		
Name	Threshold(b)	Target(c)	Maximum(d)
Richard D. Kinder(e)	$ —	$ —	$ —
Kimberly A. Dang	500,000	1,000,000	1,500,000
Steven J. Kean	750,000	1,500,000	3,000,000
Thomas A. Martin	500,000	1,000,000	1,500,000
C. Park Shaper	750,000	1,500,000	3,000,000

Table of Contents

(a) See "—Compensation Discussion and Analysis—Elements of Compensation" and "—Possible Annual Cash Bonus (Annual Cash Incentive)" above for further discussion of these awards.

(b) Represents the maximum bonus opportunity available to the executive officer if one of the financial performance objectives was met.

(c) Represents the maximum bonus opportunity available to the executive officer if both of the financial performance objectives were met.

(d) Represents the maximum bonus opportunity available to the executive officer if both of the financial performance objectives were exceeded by 10% or more.

(e) Declined to participate.

Outstanding Equity Awards at Fiscal Year-End

Option Awards and Stock Awards

For each of the fiscal years 2010 through 2012, none of the named executive officers has been awarded any stock options, restricted stock or similar stock-based awards, and we had no expectation of granting any such awards to the named executive officers while any of the Sponsor Investors held Class A shares. On December 26, 2012, the last of the Sponsor Investors converted its remaining Class A shares into Class P shares. As a result, all Class B shares have also converted into Class P shares, and none were outstanding as of December 31, 2012.

Stock Vested

The Class B shares were not subject to time vesting. However, viewing the conversion of Class B shares into Class P shares as "vesting" of stock awards, the following table sets forth (i) the number of Class P shares acquired by the named executive officers upon the conversions of Class B shares during 2012; and (ii) the value realized upon such conversions and from Class B share priority dividends during 2012. The Class P shares acquired and value realized set forth in the following table reduced both the number of Class P shares and the amount of dividends that otherwise would have been received by the Investors with respect to their Class A shares. These shares acquired and value realized in no way diluted, or impacted the dividends received by, KMI's public shareholders.

Name	Number of Class P shares acquired(a)	Value realized(b)
Richard D. Kinder(c)	31,562,473	$ 1,116,685,088
Kimberly A. Dang(d)	1,972,654	69,792,802
Steven J. Kean	6,312,493	223,336,965
Thomas A. Martin	789,061	27,917,100
C. Park Shaper(e)	8,679,678	307,088,334

(a) The number of Class B shares converted was as follows: Mr. Kinder – 37,653,039; Mrs. Dang – 2,353,315; Mr. Kean – 7,530,608; Mr. Martin – 941,326; and Mr. Shaper – 10,354,586. See notes (c), (d) and (e).

(b) Calculated as the number of Class P shares acquired on the applicable conversion date, multiplied by, the closing market price of the Class P shares on such date. Also includes the amount of "priority dividends" (as defined in KMI's certificate of incorporation) received on the Class B shares, which dividends reduced the value that was ultimately realized on the Class B shares.

(c) Includes 10,520,824 Class P shares acquired by a limited partnership into which Mr. Kinder had transferred 12,551,013 Class B shares that converted to Class P shares in 2012. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.

(d) Includes 1,972,654 Class P shares acquired by a limited partnership into which Ms. Dang had transferred all of her Class B shares. Mrs. Dang disclaims 10% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.

(e) Includes 8,679,678 Class P shares acquired by a limited partnership into which Mr. Shaper transferred all of his Class B shares. Mr. Shaper disclaims 21% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.

Risks Associated with Compensation Practices

KMGP Services Company, Inc., KMI and Kinder Morgan Canada Inc. employ all persons necessary for the operation of our business, and in our opinion, our compensation policies and practices for all persons necessary for the operation of our business do not create risks that are reasonably likely to have a material adverse effect on our business, financial position, results of operations or cash flows. Our belief is based on the fact that our employee compensation—primarily consisting of annual salaries and cash bonuses—is based on performance that does not reward risky behavior and is not tied to entering into transactions that pose undue risks to us.

Director Compensation

Compensation Committee Interlocks and Insider Participation

The compensation committee of KMR functions as our compensation committee. KMR's compensation committee is comprised of Mr. Ted A. Gardner, Mr. Gary L. Hultquist and Mr. Perry M. Waughtal. KMR's compensation committee makes compensation decisions regarding the executive officers of our general partner and its delegate, KMR. Mr. Richard D. Kinder, Mr. James E. Street, Mr. C. Park Shaper and Mr. Steven J. Kean, who are executive officers of KMR, participate in the deliberations of the KMR compensation committee concerning executive officer compensation. None of the members of KMR's compensation committee is or has been one of our officers or employees, and none of our executive officers served during 2012 on a board of directors or compensation committee of another entity which has employed any of the members of KMR's board of directors or compensation committee.

Directors Fees

Awards under our Common Unit Compensation Plan for Non-Employee Directors serve as compensation for each of KMR's three non-employee directors. This plan is described in Note 12 "—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors" to our consolidated financial statements included elsewhere in this report. Directors of KMR who are also employees of KMI (Messrs. Richard D. Kinder and C. Park Shaper) do not receive compensation in their capacity as directors.

The following table discloses the compensation earned by each of KMR's non-employee directors for board service during fiscal year 2012. In addition, directors are reimbursed for reasonable expenses in connection with board meetings.

Name	Fees Earned or Paid in Cash	Common Unit Awards	All Other Compensation	Total
Ted A. Gardner	$ 180,000	$ —	$ —	$ 180,000
Gary L. Hultquist	180,000	—	—	180,000
Perry M. Waughtal	180,000	—	—	180,000

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Compensation Committee Report

Throughout fiscal 2012, the compensation committee of KMR's board of directors was comprised of three directors (Mr. Ted A. Gardner, Mr. Gary L. Hultquist and and Mr. Perry M. Waughtal), each of whom the KMR board of directors has determined meets the criteria for independence under KMR's governance guidelines and the New York Stock Exchange rules.

The KMR compensation committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2012 with management. Based on this review and discussion, the KMR compensation committee recommended to its board of directors that this Compensation Discussion and Analysis be included in this annual report on Form 10-K for the fiscal year 2012.

KMR Compensation Committee:

Ted A. Gardner

Gary L. Hultquist

Perry M. Waughtal

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

The following table sets forth information as of January 31, 2013, regarding (i) the beneficial ownership of our common and KMR shares by all directors of our general partner and KMR, its delegate, by each of the named executive officers identified in Item 11 "Executive Compensation" and by all directors and executive officers as a group; and (ii) the beneficial ownership of our common units and KMR shares by all persons known by our general partner to own beneficially at least 5% of such units or shares. Unless otherwise noted, the address of each person below is c/o Kinder Morgan Energy Partners, L.P., 1001 Louisiana Street, Suite 1000, Houston, Texas 77002.

Amount and Nature of Beneficial Ownership(a)

	Common Units		Class B Units		Kinder Morgan Management Shares	
Name	**Number of Units**	**Percent of Class(b)**	**Number of Units**	**Percent of Class(c)**	**Number of Shares**	**Percent of Class(d)**
Richard D. Kinder(e)	315,979	*	—	—	294,952	*
C. Park Shaper	4,000	*	—	—	38,356	*
Ted A. Gardner	43,404	*	—	—	70,744	*
Gary L. Hultquist	1,000	*	—	—	—	—
Perry M. Waughtal(f)	46,918	*	—	—	85,448	*
Steven J. Kean	1,780	*	—	—	2,591	*
Thomas A. Martin	—	—	—	—	5,460	*
Kimberly A. Dang	121	*	—	—	636	*
Directors and Executive Officers as a group (14 persons)(g)	419,793	*	—	—	510,446	*
Kinder Morgan, Inc.(h)	21,038,003	8.32%	5,313,400	100.00%	14,957,793	12.99%
Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne(i)	—	—	—	—	9,054,240	7.87%

* Less than 1%.

(a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the units and shares listed.

(b) As of January 31, 2013, we had 252,756,425 common units issued and outstanding.

(c) As of January 31, 2013, we had 5,313,400 Class B units issued and outstanding.

(d) Represent the limited liability company shares of KMR. As of January 31, 2013, there were 115,118,338 issued and outstanding KMR shares, including three voting shares owned by our general partner. In all cases, our i-units will be voted in proportion to the affirmative and negative votes, abstentions and non-votes of owners of KMR shares. Through the provisions in our partnership agreement and KMR's limited liability company agreement, the number of outstanding KMR shares, including voting shares owned by our general partner, and the number of our i-units will at all times be equal.

(e) Includes 7,879 common units and 1,218 KMR shares owned by Mr. Kinder's spouse. Mr. Kinder disclaims all beneficial and pecuniary interest in these common units and KMR shares.

(f) Includes 17,500 KMR shares held by a limited partnership, the general partner of which is owned 50% by Mr. Waughtal and 50% by his spouse and jointly controlled by Mr. Waughtal and his spouse. Mr. Waughtal disclaims 99.5% of any beneficial and pecuniary interest in these shares.

(g) See notes (e) through (g). Also includes 963 KMR shares held by a custodial account for the benefit of children of an executive officer. The executive officer disclaims any beneficial ownership in such KMR shares.

(h) Includes common units owned by KMI and its consolidated subsidiaries, including 1,724,000 common units owned by Kinder Morgan G.P., Inc.

(i) As reported on the Schedule 13G/A filed January 9, 2013 by Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne, Kayne Anderson Capital Advisors, L.P. reported that in regard to KMR shares, it had sole voting power over 0 shares, shared voting power over 9,054,240 shares, sole disposition power over 0 shares and shared disposition power over 9,054,240 shares. Mr. Kayne reports that in regard to KMR shares, he had sole voting power over 495 shares, shared voting power over 9,054,240 shares, sole disposition power over 495 shares and shared disposition power over 9,054,240 shares. Kayne Anderson Capital Advisors, L.P.'s and Richard A. Kayne's address is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067.

KMR's board of directors and its compensation committee previously established a minimum ownership requirement for members of the board with respect to KMP units, KMR shares or a combination thereof. As of December 31, 2012, one member of the board, Mr. Hultquist, did not satisfy this minimum ownership requirement. Effective February 13, 2013, the board, by unanimous consent, determined to provide a waiver of the minimum ownership requirement in the case of Mr. Hultquist until December 31, 2013, or such later date determined by the board.

The following table sets forth information as of January 31, 2013, regarding the beneficial ownership of KMI Class P shares by all directors of our general partner and KMR, its delegate, by each of the named executive officers identified in Item 11 "Executive Compensation" and by all directors and executive officers as a group.

Amount and Nature of Beneficial Ownership(a)

	KMI Class P Shares	
Name	**Number of Shares**	**Percent of Class(b)**
Richard D. Kinder(c)	240,872,511	23.3%
C. Park Shaper(d)	10,663,504	1.0%
Ted A. Gardner	200,000	*
Gary L. Hultquist	—	—
Perry M. Waughtal(e)	10,000	*
Steven J. Kean(f)	7,394,843	*
Thomas A. Martin(g)	883,824	*
Kimberly A. Dang(h)	2,110,498	*
Directors and Executive Officers as a group (14 persons)(i)	277,105,824	26.8%

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* Less than 1%.

(a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the shares listed.

(b) As of January 31, 2013, KMI had 1,035,669,044 Class P shares issued and outstanding.

(c) Includes 40,467 Class P shares owned by Mr. Kinder's wife. Mr. Kinder disclaims any and all beneficial or pecuniary interest in the Class P shares held by his wife. Also includes 11,072,258 Class P shares held by a limited partnership of which Mr. Kinder controls the voting and disposition power. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in these shares.

(d) Includes 1,957,784 Class P shares held by a limited partnership of which Mr. Shaper controls the voting and disposition power. Mr. Shaper disclaims 98% of any beneficial and pecuniary interest in these Class P shares.

(e) Includes 10,000 Class P shares held by a limited partnership, the general partner of which is owned 50% by Mr. Waughtal and 50% by his spouse and jointly controlled by Mr. Waughtal and his spouse. Mr. Waughtal disclaims 99.5% of any beneficial and pecuniary interest in these shares.

(f) Includes 230,000 Class P shares held by a limited partnership. Mr. Kean is the sole general partner of the limited partnership, and two trusts of which family members of Mr. Kean are sole beneficiaries and Mr. Kean is sole trustee each own a 49.5% limited partner interest in the limited partnership. Mr. Kean disclaims beneficial ownership of the Class P shares held by the limited partnership except to the extent of his pecuniary interest therein. Also includes 700,000 Class P shares owned by a charitable foundation of which Mr. Kean is a member of the board of directors and shares voting and investment power. Mr. Kean disclaims any beneficial ownership in these 700,000 shares.

(g) Includes 148,950 Class P shares held by a trust for the benefit of family members of Mr. Martin with respect to which Mr. Martin shares voting and disposition power. Mr. Martin disclaims any beneficial ownership in these shares.

(h) Includes 2,026,048 Class P shares held by a limited partnership of which Mrs. Dang controls the voting and disposition power. Mrs. Dang disclaims 10% of any beneficial and pecuniary interest in these shares.

(i) See notes (c) through (h) above. Also includes 5,532,122 Class P shares held by limited partnerships, limited liability companies or trusts with respect to which executive officers have sole or shared voting or disposition power, but in respect of which Class P shares the executive officers disclaim all or a portion of any beneficial or pecuniary interest.

Equity Compensation Plan Information

The following table sets forth information regarding our equity compensation plans as of December 31, 2012. Specifically, the table provides information regarding our Common Unit Compensation Plan for Non-Employee Directors, described in Item 11 "Executive Compensation—Director Compensation—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors," and Note 12 to our consolidated financial statements included elsewhere in this report.

Plan Category	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—
Equity compensation plans not approved by security holders	69,782
Total	69,782

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Related Transactions

Our policy is that (i) employees must obtain authorization from the appropriate business unit president of the relevant company or head of corporate function, and (ii) directors, business unit presidents, executive officers and heads of corporate functions must obtain authorization from the non-interested members of the audit committee of the applicable board of directors, for any business relationship or proposed business transaction in which they or an immediate family member has a direct or indirect interest, or from which they or an immediate family member may derive a personal benefit (a "related party transaction"). When deciding whether to authorize a related party transaction, our business unit presidents and the non-interested members of the audit committee of the applicable board of directors, consider, among other things, the nature of the transaction and the relationship, the dollar amount involved, and the availability of reasonable alternatives.

The maximum dollar amount of related party transactions that may be approved as described above in this paragraph in any calendar year is $1.0 million. Any related party transactions that would bring the total value of such transactions to greater than $1.0 million must be referred to the audit committee of the appropriate board of directors for approval or to determine the procedure for approval.

For further information regarding our related party transactions, see Note 11 to our consolidated financial statements included elsewhere in this report.

Director Independence

Our limited partnership agreement provides for us to have a general partner rather than a board of directors. Pursuant to a delegation of control agreement, our general partner delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. Through the operation of that agreement and our partnership agreement, KMR manages and controls our business and affairs, and the board of directors of KMR performs the functions of and acts as our board of directors. Similarly, the standing committees of KMR's board of directors function as standing committees of our board. KMR's board of directors is comprised of the same persons who comprise our general partner's board of directors. References in this report to the board mean KMR's board, acting as our board of directors, and references to committees mean KMR's committees, acting as committees of our board of directors.

The board has adopted governance guidelines for the board and charters for the audit committee, nominating and governance committee and compensation committee. The governance guidelines and the rules of the New York Stock Exchange require that a majority of the directors be independent, as described in those guidelines, the committee charters and rules, respectively. Copies of the guidelines and committee charters are available on our Internet website at www.kindermorgan.com.

As described above, each of Mr. Gardner, Mr. Hultquist and Mr. Waughtal is also an independent director of our general partner. Further, each has no family relationship with any of the directors or executive officers of KMR, our general partner or us, and each has no direct or indirect material interest in any transaction or proposed transaction required to be reported under Section 404(a) of Regulation S-K.

The board has affirmatively determined that Messrs. Gardner, Hultquist and Waughtal, who constitute a majority of the directors, are independent as described in our governance guidelines and the New York Stock Exchange rules. In conjunction with all regular quarterly and certain special board meetings, these three non-management directors also meet in executive session without members of management. In January 2013, Mr. Waughtal was elected for a one year term to serve as lead director to develop the agendas for and preside at these executive sessions of independent directors.

The governance guidelines and our audit committee charter, as well as the rules of the New York Stock Exchange and the Securities and Exchange Commission, require that members of the audit committee satisfy independence requirements in addition to those above. The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

Item 14. *Principal Accounting Fees and Services*

The following sets forth fees billed for the audit and other services provided by PricewaterhouseCoopers LLP for the fiscal years ended December 31, 2012 and 2011 (in dollars):

	Year Ended December 31,	
	2012	2011
Audit fees(a)	$ 3,861,670	$ 2,949,566
Tax fees(b)	2,280,153	2,366,165
Total	$ 6,141,823	$ 5,315,731

(a) Includes fees for integrated audit of annual financial statements and internal control over financial reporting, reviews of the related quarterly financial statements, and reviews of documents filed with the Securities and Exchange Commission. 2012 and 2011 amounts also include fees of $909,000 and $643,000, respectively, for GAAP audits of certain stand-alone financial statements; and fees of $525,000 for 2012 audit costs related to our FTC Natural Gas Pipelines disposal group.

(b) For 2012 and 2011, amounts include fees of $2,267448 and $2,350,480, respectively, billed for professional services rendered for tax processing and preparation of Forms K-1 for our unitholders; and fees of $12,705 and $15,685, respectively, billed for professional services rendered for Internal Revenue Service assistance, tax function effectiveness, and for general state, local and foreign tax compliance and consulting services.

All services rendered by PricewaterhouseCoopers LLP are permissible under applicable laws and regulations, and were pre-approved by the audit committee of KMR and our general partner. Pursuant to the charter of the audit committee of KMR, the delegate of our general partner, the committee's primary purposes include the following: (i) to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; (ii) to pre-approve all audit and non-audit services, including tax services, to be provided, consistent with all applicable laws, to us by our external auditors; and (iii) to establish the fees and other compensation to be paid to our external auditors. The audit committee has reviewed the external auditors' fees for audit and non audit services for fiscal year 2012. The audit committee has also considered whether such non audit services are compatible with maintaining the external auditors' independence and has concluded that they are compatible at this time.

Furthermore, the audit committee will review the external auditors' proposed audit scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, will regularly review with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and will, at least annually, use its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items): (i) the auditors' internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors; (iii) the independence of the external auditors; and (iv) the aggregate fees billed by our external auditors for each of the previous two fiscal years.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) *Financial Statements and Financial Statement Schedules*

See “Index to Financial Statements” set forth on page 109.

(a)(3) *Exhibits*

*2.1— Purchase and Sale Agreement, dated as of August 17, 2012, between Kinder Morgan Operating L.P. “A” and Tallgrass Energy Partners, LP (filed as exhibit 2.1 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K filed August 23, 2012).

*2.2— Purchase and Sale Agreement, dated as of August 17, 2012, between Kinder Morgan Operating L.P. “A” and Tallgrass Energy Partners, LP (filed as exhibit 2.2 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K filed August 23, 2012).

*2.3— Contribution Agreement, dated as of August 6, 2012, among Kinder Morgan, Inc., El Paso TGPC Investments, L.L.C., El Paso EPNG Investments, L.L.C. and Kinder Morgan Energy Partners, L.P. (filed as exhibit 2.1 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K filed August 6, 2012).

*3.1— 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 (File No. 1-11234) for the quarter ended June 30, 2001, filed on August 9, 2001).

*3.2— 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 (File No. 1-11234), filed November 22, 2004).

*3.3— 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 (File No. 1-11234), filed May 5, 2005).

*3.4— 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).

3.5— Amendment No. 4 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P.

*4.1— Form of certificate evidencing Common Units representing the common units of Kinder Morgan Energy Partners, L.P. (included as Exhibit A to Third Amended and Restated Agreement of Limited Partnership, filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P.’s quarterly report on Form 10-Q for the quarter ended June 30, 2001 File No. 1701930, filed August 9, 2001).

*4.2— 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 the Partnership’s Current Report on Form 8-K filed February 16, 1999, File No. 1-11234 (the “February 16, 1999 Form 8-K”)).

*4.3— 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. Form 10-K for 2001 (File No. 1-11234)).

*4.4— Indenture dated January 2, 2001 between Kinder Morgan Energy Partners 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. Form 10-K (File No. 1-11234) for 2000).

*4.5— Indenture dated January 2, 2001 between Kinder Morgan Energy Partners and First Union National Bank, as trustee, relating to Subordinated Debt Securities (including form of Subordinated Debt Securities) (filed as Exhibit 4.12 to Kinder Morgan Energy Partners, L.P. Form 10-K (File No. 1-11234) for 2000).

*4.6— Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed on March 14, 2001).

*4.7— 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. Form 8-K (File No. 1-11234), filed on March 14, 2001).

*4.8— 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. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.9— Specimen of 7.125% Notes due March 15, 2012 in book-entry form (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.10— 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. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.11— 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 (File No. 333-100346) filed on October 4, 2002 (the “October 4, 2002 Form S-4”)).

*4.12— 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 the October 4, 2002 Form S-4 (File No. 333-100346)).

*4.13— Form of 7.30% Note (contained in the Indenture filed as Exhibit 4.1 to the October 4, 2002 Form S-4 (File No. 333-100346)).

*4.14— 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 (File No. 333-102961) filed on February 4, 2003 (the “February 4, 2003 Form S-3”)).

*4.15— 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 February 4, 2003 Form S-3 (File No. 333-102961)).

*4.16— Subordinated Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.4 to the February 4, 2003 Form S-3 (File No. 333-102961)).

*4.17— Form of Subordinated Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Subordinated Indenture filed as Exhibit 4.4 to the February 4, 2003 Form S-3 (File No. 333-102961)).

*4.18— 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. Form 10-K for 2003 filed March 5, 2004 (File No. 001-11234)).

*4.19— 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. Form 10-K for 2004 filed March 4, 2005 (File No. 1-11234)).

*4.20— 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. Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005 (File No. 1-11234)).

*4.21— 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 February 1, 2017 and 6.50% Senior Notes due February 1, 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2006 filed March 1, 2007 (File No. 1-11234)).

*4.22— 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 January 15, 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2007 filed August 8, 2007 (File No. 1-11234)).

*4.23— 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 February 15, 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2007 filed February 26, 2008 (File No. 1-11234)).

*4.24— 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 February 1, 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2008 filed February 23, 2009).

*4.25— 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 February 15, 2015, and the 6.85% Senior Notes due February 15, 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2009 filed August 3, 2009).

*4.26— 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 March 1, 2021, and the 6.50% Senior Notes due September 1, 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2009 filed October 30, 2009).

*4.27— Registration Rights Agreement, dated as of January 15, 2010, between US Development Group LLC and Kinder Morgan Energy Partners, L.P. (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed January 19, 2010).

*4.28— Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due September 15, 2020, and the 6.55% Senior Notes due September 15, 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2010 filed July 30, 2010).

*4.29— Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.50% Senior Notes due March 1, 2016, and the 6.375% Senior Notes due March 1, 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended March 31, 2011 filed April 29, 2011).

*4.30— Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.15% Senior Notes due March 1, 2022, and the 5.625% Senior Notes due September 1, 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011).

Table of Contents

*4.31— 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 3.95% Senior Notes due September 1, 2022 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended March 31, 2012 filed April 27, 2012).

*4.32— Certificate of the Vice President and Chief Financial Officer and the 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 3.45% Senior Notes due February 15, 2023, and the 5.00% Senior Notes due August 15, 2042 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2012 filed October 29, 2012).

4.33— Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

*10.1— 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)).

*10.2— 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)).

*10.3— 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)).

*10.4— 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)).

*10.5— Three-Year 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.'s Current Report on Form 8-K, filed on June 24, 2010).

*10.6— 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 the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2011 (File No. 1-11234)).

*10.7— Kinder Morgan, Inc. 2011 Stock Incentive Plan (filed as Exhibit 10.1 to Kinder Morgan, Inc.'s Form 10-Q for the quarter ended March 31, 2011 (File No. 1-35081) (the "KMI 10-Q")).

*10.8— Form of Restricted Stock Agreement (filed as Exhibit 10.2 to the KMI 10-Q).

*10.9— Kinder Morgan, Inc. Employee Stock Purchase Plan (filed as Exhibit 10.5 to the KMI 10-Q).

*10.10— Kinder Morgan, Inc. Annual Incentive Plan (filed as Exhibit 10.6 to the KMI 10-Q).

*10.11— Severance Agreement with C. Park Shaper (filed as Exhibit 10.7 to the KMI 10-Q).

*10.12— Severance Agreement with Steven J. Kean (filed as Exhibit 10.8 to the KMI 10-Q).

*10.13— Severance Agreement with Kimberly A. Dang (filed as Exhibit 10.9 to the KMI 10-Q).

*10.14— Severance Agreement with Joseph Listengart (filed as Exhibit 10.10 to the KMI 10-Q).

*10.15— Credit Agreement dated as of August 6, 2012 among Kinder Morgan Energy Partners, L.P.; Wells Fargo Bank, National Association, as Administrative Agent; Barclays Bank PLC, as Syndication Agent; and the lenders party thereto (filed as exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed August 10, 2012).

11.1— Statement re: computation of per share earnings.

12.1— Statement re: computation of ratio of earnings to fixed charges.

21.1— List of Subsidiaries.

23.1— Consent of PricewaterhouseCoopers LLP.

23.2— Consent of Netherland, Sewell & Associates, Inc.

31.1— Certification by CEO pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2— Certification by CFO pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1— Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2— Certification by CFO 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— Estimates of the net reserves and future net revenues, as of December 31, 2012, 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, 2012, 2011 and 2010; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010; (iii) our Consolidated Balance Sheets as of December 31, 2012 and 2011; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; (v) our Consolidated Statements of Partners' Capital for the years ended December 31, 2012, 2011 and 2010; and (vi) the notes to our Consolidated Financial Statements.

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

Table of Contents

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of Kinder Morgan Energy Partners, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Partnership'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 Partnership's 2012 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Partnership'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 Partnership's 2012 Annual Report on Form 10-K, management has excluded Tennessee Gas Pipeline Company L.L.C. from its assessment of internal control over financial reporting as of December 31, 2012 because it was acquired in a purchase business combination by Kinder Morgan, Inc. on May 25, 2012 and dropped down to the Partnership shortly thereafter. We have also excluded Tennessee Gas Pipeline Company L.L.C. from our audit of internal control over financial reporting. Tennessee Gas Pipeline Company L.L.C. is a wholly-owned subsidiary whose total assets and total revenues represent 25% and 7%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 19, 2013

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions, Except Per Unit Amounts)

	Year Ended December 31,		
	2012	**2011**	**2010**
Revenues			
Natural gas sales	$ 2,514	$ 3,305	$ 3,571
Services	3,637	2,942	2,837
Product sales and other	2,491	1,642	1,331
Total Revenues	8,642	7,889	7,739
Operating Costs, Expenses and Other			
Gas purchases and other costs of sales	2,990	3,278	3,499
Operations and maintenance	1,531	1,490	1,366
Depreciation, depletion and amortization	1,093	928	879
General and administrative	493	473	375
Taxes, other than income taxes	223	174	160
Other expense (income)	(28)	(11)	—
Total Operating Costs, Expenses and Other	6,302	6,332	6,279
Operating Income	2,340	1,557	1,460
Other Income (Expense)			
Earnings from equity investments	339	224	136
Amortization of excess cost of equity investments	(7)	(7)	(6)
Interest expense	(658)	(534)	(508)
Interest income	23	21	20
Loss on remeasurement of previously held equity interest in KinderHawk to fair value (Note 3)	—	(167)	—
Other, net	18	18	24
Total Other Income (Expense)	(285)	(445)	(334)
Income from Continuing Operations Before Income Taxes	2,055	1,112	1,126
Income Tax (Expense)	(30)	(45)	(34)
Income from Continuing Operations	2,025	1,067	1,092
Discontinued Operations (Note 3)			
Income from operations of FTC Natural Gas Pipelines disposal group	160	201	235
(Loss) on remeasurement to fair value and sale of FTC Natural Gas Pipelines disposal group	(829)	—	—
(Loss) Income from Discontinued Operations	(669)	201	235
Net Income	1,356	1,268	1,327
Net Income Attributable to Noncontrolling Interests	(17)	(10)	(11)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 1,339	$ 1,258	$ 1,316
Calculation of Limited Partners' Interest in Net Income (Loss) Attributable to Kinder Morgan Energy Partners, L.P.:			
Income from Continuing Operations	$ 2,001	$ 1,059	$ 1,083
Less: Pre-acquisition income from operations of drop-down asset group allocated to General Partner	(23)	—	—
Add: Drop-down asset group severance expense allocated to General Partner	9	—	—
Less: General Partner's remaining Interest	(1,410)	(1,173)	(883)
Limited Partners' Interest	577	(114)	200
Add: Limited Partners' Interest in Discontinued Operations	(655)	197	231
Limited Partners' Interest in Net (Loss) Income	$ (78)	$ 83	$ 431
Limited Partners' Net Income (Loss) per Unit:			
Income (Loss) from Continuing Operations	$ 1.64	$ (0.35)	$ 0.65
(Loss) Income from Discontinued Operations	(1.86)	0.60	0.75
Net (Loss) Income	$ (0.22)	$ 0.25	$ 1.40
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	351	326	307
Per Unit Cash Distribution Declared	$ 4.98	$ 4.61	$ 4.40

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)

	Year Ended December 31,		
	2012	2011	2010
Net Income	$ 1,356	$ 1,268	$ 1,327
Other Comprehensive Income (Loss):			
Change in fair value of derivatives utilized for hedging purposes	117	14	(76)
Reclassification of change in fair value of derivatives to net income	(8)	256	189
Foreign currency translation adjustments	44	(45)	100
Adjustments to pension and other postretirement benefit plan liabilities	9	(34)	(2)
Total Other Comprehensive Income	162	191	211
Comprehensive Income	1,518	1,459	1,538
Comprehensive Income Attributable to Noncontrolling Interests	(19)	(12)	(13)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 1,499	$ 1,447	$ 1,525

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 518	$ 409
Accounts, notes and interest receivable, net	1,112	884
Inventories	292	172
Fair value of derivative contracts	55	72
Assets held for sale	211	—
Other current assets	56	39
Total current assets	2,244	1,576
Property, plant and equipment, net	19,603	15,596
Investments	3,048	3,346
Notes receivable	51	165
Goodwill	4,606	1,436
Other intangibles, net	1,095	1,152
Fair value of derivative contracts	634	632
Deferred charges and other assets	813	200
Total Assets	$ 32,094	$ 24,103
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 1,155	$ 1,638
Cash book overdrafts	44	21
Accounts payable	991	706
Accrued interest	306	259
Fair value of derivative contracts	21	121
Accrued other current liabilities	648	374
Total current liabilities	3,165	3,119
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	14,714	11,183
Debt fair value adjustments	1,461	1,055
Total long-term debt	16,175	12,238
Deferred income taxes	249	250
Fair value of derivative contracts	13	39
Other long-term liabilities and deferred credits	913	853
Total long-term liabilities and deferred credits	17,350	13,380
Total Liabilities	20,515	16,499
Commitments and contingencies (Notes 8, 12 and 16)		
Partners' Capital		
Common units (252,756,425 and 232,677,222 units issued and outstanding as of December 31, 2012 and 2011, respectively)	4,723	4,347
Class B units (5,313,400 and 5,313,400 units issued and outstanding as of December 31, 2012 and 2011, respectively)	14	42
i-units (115,118,338 and 98,509,392 units issued and outstanding as of December 31, 2012 and 2011, respectively)	3,564	2,857
General partner	2,860	259
Accumulated other comprehensive income	163	3
Total Kinder Morgan Energy Partners, L.P.'s partners' capital	11,324	7,508
Noncontrolling interests	255	96
Total Partners' Capital	11,579	7,604
Total Liabilities and Partners' Capital	$ 32,094	$ 24,103

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

Table of Contents

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)

	Year Ended December 31,		
	2012	2011	2010
Cash Flows From Operating Activities			
Net Income	$ 1,356	$ 1,268	$ 1,327
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,100	955	905
Amortization of excess cost of equity investments	7	7	6
Loss from the remeasurement of net assets to fair value and the sale of discontinued operations (net of cash selling expenses)(Note 3)	751	167	—
Noncash compensation and severance expense allocated from KMI (Note 11)	7	90	5
Earnings from equity investments	(409)	(311)	(223)
Distributions from equity investments	366	286	220
Proceeds from termination of interest rate swap agreements	53	73	157
Changes in components of working capital:			
Accounts receivable	(209)	14	18
Inventories	(89)	(36)	19
Other current assets	2	(7)	(9)
Accounts payable	133	38	(6)
Cash book overdrafts	24	(12)	(2)
Accrued interest	18	19	17
Accrued liabilities	138	(9)	—
Rate reparations, refunds and other litigation reserve adjustments	(42)	171	(34)
Other, net	(29)	161	20
Net Cash Provided by Operating Activities	3,177	2,874	2,420
Cash Flows From Investing Activities			
Payment to KMI for drop-down asset group, net of cash acquired (Note 3)	(3,482)	—	—
Acquisitions of investments	—	(971)	(926)
Acquisitions of assets	(83)	(208)	(288)
Proceeds from disposal of discontinued operations	1,791	—	—
Repayments from related party	45	31	3
Capital expenditures	(1,806)	(1,199)	(1,004)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	100	25	34
Contributions to investments	(205)	(371)	(299)
Distributions from equity investments in excess of cumulative earnings	152	214	190
Other, net	(13)	62	(25)
Net Cash Used in Investing Activities	(3,501)	(2,417)	(2,315)
Cash Flows From Financing Activities			
Issuance of debt	9,270	7,502	7,140
Payment of debt	(8,011)	(6,394)	(6,186)
Debt issue costs	(16)	(18)	(23)
Proceeds from issuance of i-units	727	—	—
Proceeds from issuance of common units	909	955	759
Contributions from noncontrolling interests	62	29	12
Contributions from General Partner	45	—	—
Distributions to partners and noncontrolling interests:			
Common units	(1,162)	(1,030)	(919)
Class B units	(26)	(24)	(23)
General Partner	(1,340)	(1,161)	(862)
Noncontrolling interests	(32)	(28)	(23)
Other, net	(1)	—	—
Net Cash Provided by (Used in) Financing Activities	425	(169)	(125)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	8	(8)	2
Net increase (decrease) in Cash and Cash Equivalents	109	280	(18)
Cash and Cash Equivalents, beginning of period	409	129	147
Cash and Cash Equivalents, end of period	$ 518	$ 409	$ 129

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In Millions)

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Noncash Investing and Financing Activities			
Net assets acquired by the transfer of the drop-down asset group	$ 6,361	$ —	$ —
Assets acquired or liabilities settled by the issuance of common units	$ 686	$ 24	$ 82
Assets acquired by the assumption or incurrence of liabilities	$ —	$ 207	$ 14
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	$ 637	$ 518	$ 473
Cash paid (received) during the period for income taxes	$ 17	$ 10	$ (2)

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In Millions, Except Units)

	2012		2011		2010	
	Units	Amount	Units	Amount	Units	Amount
Common units:						
Beginning Balance	232,677,222	$ 4,347	218,880,103	$ 4,282	206,020,826	$ 4,058
Net (loss) income	—	(56)	—	57	—	299
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	—	—	2,450	—	2,450	—
Units issued as consideration in the acquisition of assets	8,661,627	686	324,961	24	1,287,287	82
Units issued for cash	11,417,576	909	13,469,708	955	11,569,540	759
Distributions	—	(1,162)	—	(1,030)	—	(919)
Noncash compensation and severance expense allocated from KMI	—	4	—	61	—	3
Sale of noncontrolling interest-retained control	—	(4)	—	—	—	—
Other adjustments	—	(1)	—	(2)	—	—
Ending Balance	252,756,425	4,723	232,677,222	4,347	218,880,103	4,282
Class B units:						
Beginning Balance	5,313,400	42	5,313,400	63	5,313,400	78
Net (loss) income	—	(2)	—	2	—	8
Distributions	—	(26)	—	(24)	—	(23)
Noncash compensation and severance expense allocated from KMI	—	—	—	1	—	—
Ending Balance	5,313,400	14	5,313,400	42	5,313,400	63
i-Units:						
Beginning Balance	98,509,392	2,857	91,907,990	2,808	85,538,266	2,682
Net (loss) income	—	(20)	—	24	—	124
Units issued for cash	10,120,000	727	—	—	—	—
Distributions	6,488,946	—	6,601,402	—	6,369,724	—
Noncash compensation and severance expense allocated from KMI	—	1	—	26	—	2
Sale of noncontrolling interest-retained control	—	(1)	—	—	—	—
Other adjustments	—	—	—	(1)	—	—
Ending Balance	115,118,338	3,564	98,509,392	2,857	91,907,990	2,808
General partner:						
Beginning Balance	—	259	—	244	—	221
Net income	—	1,417	—	1,175	—	885
Distributions	—	(1,340)	—	(1,161)	—	(862)
Drop-Down acquisition (Note 3)	—	2,472	—	—	—	—
Noncash compensation and severance expense allocated from KMI	—	—	—	1	—	—
Contributions	—	45	—	—	—	—
Other adjustments	—	7	—	—	—	—
Ending Balance	—	2,860	—	259	—	244
Accumulated other comprehensive income (loss):						
Beginning Balance	—	3	—	(186)	—	(395)
Change in fair value of derivatives utilized for hedging purposes	—	115	—	14	—	(75)
Reclassification of change in fair value of derivatives to net income	—	(8)	—	253	—	187
Foreign currency translation adjustments	—	44	—	(44)	—	99
Adjustments to pension and other postretirement benefit plan liabilities	—	9	—	(34)	—	(2)
Ending Balance	—	163	—	3	—	(186)
Total Kinder Morgan Energy Partners, L.P. Partners’ Capital	373,188,163	$ 11,324	336,500,014	$ 7,508	316,101,493	$ 7,211
Noncontrolling interests:						
Beginning Balance	—	$ 96	—	$ 82	—	$ 80
Net income	—	17	—	10	—	11
Contributions	—	62	—	29	—	12
Distributions	—	(32)	—	(28)	—	(23)
Drop-Down acquisition (Note 3)	—	25	—	—	—	—
Change in fair value of derivatives utilized for hedging purposes	—	2	—	—	—	(1)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (continued)
(In Millions)

Reclassification of change in fair value of derivatives to net income	—	—	—	3	—	2
Foreign currency translation adjustments	—	—	—	(1)	—	1
Noncash compensation expense allocated from KMI	—	1	—	1	—	—
Sale of noncontrolling interest-retained control	—	84	—	—	—	—
Ending Balance	—	255	—	96	—	82
Total Partners' Capital	373,188,163	$ 11,579	336,500,014	$ 7,604	316,101,493	$ 7,293

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

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a Delaware limited partnership formed in August 1992. Unless the context requires otherwise, references to "we," "us," "our," "KMP," or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We own and manage a diversified portfolio of energy transportation and storage assets and presently conduct our business through five reportable business segments.

These segments and the activities performed to provide services to our customers and create value for our unitholders are as follows:

- Products Pipelines - transporting, storing and processing refined petroleum products;
- Natural Gas Pipelines - transporting, storing, buying, selling, gathering, treating and processing natural gas;
- CO_2 – transporting oil, producing, transporting and selling carbon dioxide, commonly called CO_2, for use in, and selling crude oil, natural gas and natural gas liquids produced from, enhanced oil recovery operations;
- Terminals - transloading, storing and delivering a wide variety of bulk, petroleum (including crude oil), petrochemical and other liquid products at terminal facilities located across the United States and portions of Canada; and
- Kinder Morgan Canada – transporting crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, and owning a one-third interest in an integrated oil transportation network that connects Canadian and United States producers to refineries in the U.S. Rocky Mountain and Midwest regions.

We focus on providing fee-based services to customers, generally avoiding near-term commodity price risks and taking advantage of the tax benefits of a limited partnership structure. We trade on the New York Stock Exchange under the symbol "KMP," and we conduct our operations through the following five limited partnerships: (i) Kinder Morgan Operating L.P. "A"; (ii) Kinder Morgan Operating L.P. "B"; (iii) Kinder Morgan Operating L.P. "C"; (iv) Kinder Morgan Operating L.P. "D"; and (v) Kinder Morgan CO_2 Company, L.P. Combined, the five limited partnerships are referred to as our operating partnerships, and we are the 98.9899% limited partner and our general partner is the 1.0101% general partner in each. Both we and our operating partnerships are governed by Amended and Restated Agreements of Limited Partnership, as amended, and certain other agreements that are collectively referred to in this report as the partnership agreements.

Kinder Morgan, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation and referred to as KMI in this report, indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation; however, in July 2007, our general partner issued and sold to a third party 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC. KMI's common stock trades on the New York Stock Exchange under the symbol "KMI."

Effective May 25, 2012, KMI completed its previously announced acquisition of all of the outstanding shares of El Paso Corporation, a Delaware corporation referred to as EP in this report. EP owns one of North America's largest interstate natural gas pipeline systems and an emerging midstream business. EP also owns a 41% limited partner interest and the 2% general partner interest in El Paso Pipeline Partners, L.P. KMI's acquisition of EP created one of the largest energy companies in the United States.

As of December 31, 2012, KMI and its consolidated subsidiaries owned, through KMI's general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 12.8% interest in us. In addition to the distributions it receives from its limited and general partner interests, KMI also receives an incentive distribution from us as a result of its ownership of our general partner. Including both its general and limited partner interests in us, at the 2012 distribution level, KMI received approximately 51% of all quarterly distributions of available cash from us, with approximately 45% and 6% of all quarterly distributions from us attributable to KMI's general partner and limited partner interests, respectively. At the 2011 distribution level, KMI received approximately 50% of all quarterly distributions of available cash from us, with approximately 44% and 6% of all quarterly distributions from us attributable to KMI's general partner and limited partner interests, respectively.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company formed in February 2001. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. KMR's shares represent limited liability company interests and trade on the New York Stock Exchange under the symbol "KMR."

Under the delegation of control agreement, KMR, as the delegate of our general partner, manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their majority-owned and controlled subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their majority-owned and controlled subsidiaries. As of December 31, 2012 and 2011, KMR, through its sole ownership of our i-units, owned approximately 30.8% and 29.3%, respectively, of all of our outstanding limited partner units (which are in the form of i-units that are issued only to KMR).

2. Summary of Significant Accounting Policies

Basis of Presentation

General

Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C$.

Our accompanying consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries, and we have prepared these consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. These rules and regulations conform to the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America. 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. In this report, we refer to the Financial Accounting Standards Board as the FASB and the FASB Accounting Standards Codification as the Codification.

Our financial statements are consolidated into the consolidated financial statements of KMI; however, except for the related party transactions described in Note 11 "Related Party Transactions—Asset Acquisitions and Sales," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

Effective November 1, 2012, KMI sold our (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 to Tallgrass Energy Partners, LP for approximately $1.8 billion in cash. In this report, we refer to this combined group of assets as our FTC Natural Gas Pipelines disposal group. The sale of our FTC Natural Gas Pipelines disposal group satisfied terms of a March 15, 2012 agreement between KMI and the U.S. Federal Trade Commission (FTC) to divest certain of our assets in order to receive regulatory approval for KMI's EP acquisition.

Following KMI's agreement with the FTC, we accounted for our FTC Natural Gas Pipelines disposal group as discontinued operations in accordance with the provisions of the "Presentation of Financial Statements—Discontinued Operations" Topic of the Codification. Accordingly, we (i) reclassified and excluded the 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 FTC Natural Gas Pipelines disposal group" within the discontinued operations section of our accompanying consolidated statements of income for all periods presented; and (ii) separately reported a "(Loss) on remeasurement to fair value and sale of FTC Natural Gas Pipelines disposal group" within the discontinued operations section of our accompanying consolidated statements of income for the year ended December 31, 2012. We did not, however, 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 our FTC Natural Gas Pipelines disposal group, see Note 3 "Acquisitions and Divestitures—Divestitures—FTC Natural Gas Pipelines Disposal Group - Discontinued Operations."

August 2012 KMI Asset Drop-Down

Effective August 1, 2012, we acquired the full ownership interest in the Tennessee Gas natural gas pipeline system and a 50% ownership interest in the El Paso Natural Gas pipeline system from KMI for an aggregate consideration of approximately $6.2 billion. In this report, we refer to this acquisition of assets from KMI as the drop-down transaction; the combined group of assets acquired from KMI as the drop-down asset group; the Tennessee Gas natural gas pipeline system or Tennessee Gas Pipeline Company, L.L.C. as TGP, and the El Paso Natural Gas pipeline system or El Paso Natural Gas Pipeline Company, L.L.C. as EPNG.

KMI acquired the drop-down asset group as part of its acquisition of EP on May 25, 2012 (discussed above in Note 1). Pursuant to current accounting principles in conformity with the Codification, KMI accounted for its acquisition of the drop-down asset group under the purchase accounting method, and we accounted for the drop-down transaction as a transfer of net assets between entities under common control. Accordingly, we prepared our consolidated financial statements and the related financial information contained in this report to reflect the transfer of net assets from KMI to us as if such transfer had taken place on May 25, 2012. Specifically, we (i) recognized the acquired assets and assumed liabilities at KMI's carrying value as of its acquisition date, May 25, 2012 (including all of KMI's purchase accounting adjustments); (ii) recognized any difference between our purchase price and the carrying value of the net assets we acquired as an adjustment to our Partners' Capital (specifically, as an adjustment to our general partner's capital interests); and (iii) retrospectively adjusted our consolidated financial statements, for any date after KMI's May 25, 2012 acquisition of EP, to reflect our results on a consolidated combined basis including the results of the drop-down asset group as of or at the beginning of the respective period.

Additionally, because KMI both controls us and consolidates our financial statements into its consolidated financial statements as a result of its ownership of our general partner, we fully allocated to our general partner:

- the earnings of the drop-down asset group for the period beginning May 25, 2012 and ending August 1, 2012 (and we reported this amount separately as "Pre-acquisition income from operations of drop-down asset group allocated to General Partner" within the Calculation of Limited Partners' Interest in Net Loss section of our accompanying consolidated statements of income for the year ended December 31, 2012); and

- incremental severance expense related to KMI's acquisition of EP and allocated to us from KMI (and we reported this amount separately as "Drop-down asset group severance expense allocated to General Partner" within the Calculation of Limited Partners' Interest in Net Loss section of our accompanying consolidated statements of income for the year ended December 31, 2012. We do not have any obligation, nor did we pay any amounts related to this expense.

We allocated all other 2012 earnings amounts to all of our partners according to the partnership agreements. For more information about the drop-down transaction, see Note 3 "Acquisitions and Divestitures—August 2012 KMI Asset Drop-Down." For more information on the changes to our Partners' Capital related to the drop-down transaction, see Note 10 "Partners' Capital—Adjustment to Partners' Capital from August 2012 KMI Asset Drop-Down."

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.

Cash held in escrow is restricted cash, and as of December 31, 2012, our restricted cash consisted of (i) $2 million deposited into a third-party escrow account to comply with certain contractual stipulations related to our Canadian terminal operations; and (ii) $5 million consisting of cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners. We reported this combined $7 million amount within “Other current assets” on our accompanying consolidated balance sheet. As of December 31, 2011, none of our cash was set aside or restricted for some special purpose.

Accounts Receivable

The amounts reported as “Accounts, notes and interest receivable, net” on our accompanying consolidated balance sheets as of December 31, 2012 and 2011 primarily consist of amounts due from third party payors (unrelated entities). For information on receivables due to us from related parties, see Note 11.

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 natural gas liquids, refined petroleum products, natural gas, and carbon dioxide. 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, 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 December 31, 2012 and 2011, our gas imbalance receivables—including both trade and related party receivables—totaled $13 million and $19 million, respectively, and we included these amounts within “Other current assets” on our accompanying consolidated balance sheets. As of December 31, 2012 and 2011, our gas imbalance payables—including both trade and related party payables—totaled $43 million and $9 million, respectively, and we included these amounts within “Accrued 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 system sales, excluding land, are recorded to the appropriate accumulated depreciation reserve. Gains and losses for operating systems sales and land sales are booked to income or expense accounts in accordance with regulatory accounting guidelines.

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 1.6% to 12.5%, 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.

In addition, we engage in enhanced recovery techniques in which carbon dioxide is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the carbon dioxide 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 carbon dioxide 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 measure long-lived assets that are to be disposed of by sale at the lower of book value or fair value less the cost to sell, and we review for the impairment of long-lived assets whenever events or changes in circumstances indicate that our carrying amount of an asset may not be recoverable. We would recognize an impairment loss 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 Activities (Unaudited)" included elsewhere in this report.

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. For more information on our asset retirement obligations, see Note 5 "Property, Plant and Equipment—Asset Retirement Obligations."

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 acquired net assets, and such amounts are reported separately as "Goodwill" on our accompanying consolidated balance sheets. Our total goodwill was $4,606 million as of December 31, 2012, and $1,436 million as of December 31, 2011. Goodwill cannot be amortized, but instead 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 perform our goodwill impairment test on May 31 of each year. There were no impairment charges resulting from our May 31, 2012, 2011 or 2010 impairment testing, and no event indicating an impairment has occurred subsequent to May 31, 2012.

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. For more information on our goodwill, see Note 7.

Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We generally sell natural gas under long-term agreements, generally based on Houston Ship Channel index posted prices. In some cases, we sell natural gas under short-term agreements at prevailing market prices. In all cases, we recognize natural gas sales revenues when the natural gas 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. The natural gas we market is primarily purchased gas produced by third parties, and we market this gas to power generators, local distribution companies, industrial end-users and national marketing companies. We recognize gas gathering and marketing revenues in the month of delivery based on customer nominations and generally, our natural gas marketing revenues are recorded gross, not net of cost of gas sold.

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. 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 transportation services 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. Liquids terminal minimum take-or-pay revenue is recognized at the end of the contract year or contract term depending on the terms of the contract. 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, natural gas liquids, carbon dioxide and natural gas production 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. As a result, we maintain a minimum amount of product inventory in storage.

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. For more information on our environmental disclosures, see Note 16.

Legal

We are subject to litigation and regulatory proceedings as the 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. When we identify specific litigation that is expected to continue for a significant period of time, is reasonably possible to occur, and may require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement, and we accrue for such amounts. 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. In general, we expense legal costs as incurred and all recorded legal liabilities are revised as better information becomes available. For more information on our legal disclosures, see Note 16.

Pensions and Other Postretirement Benefits

We fully recognize the overfunded or underfunded status of our consolidating subsidiaries' pension and other postretirement benefit plans as either assets or liabilities on our balance sheet. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. 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, until they are amortized to expense. For more information on our pension and postretirement benefit disclosures, see Note 9.

Noncontrolling Interests

Noncontrolling interests represents the outstanding ownership interests in our five operating limited partnerships and their 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 "Partners' Capital."

As of December 31, 2011, our noncontrolling interests consisted of the following: (i) the 1.0101% general partner interest in each of our five operating partnerships; (ii) the 0.5% special limited partner interest in SFPP, L.P.; (iii) the 33 1/3% interest in International Marine Terminals Partnership, a Louisiana partnership; (iv) the approximate 31% interest in the Pecos Carbon Dioxide Company, a Texas general partnership; (v) the 35% interest in Guilford County Terminal Company, LLC, a limited liability company; (vi) a 2.5% interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO), a limited liability company; and (vii) the 50% interest in Globalplex Partners, a Louisiana joint venture. In addition to the above, our noncontrolling interests as of December 31, 2012 included (i) an additional 42.5% interest in BOSTCO; and (ii) the 49% interest in Deeprock Development LLC, a limited liability company.

Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statement of income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner's tax attributes in us.

Some of our corporate subsidiaries and corporations in which we have an equity investment do pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the 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 not expected to be realized. For more information on our income tax disclosures, see Note 4.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which our reporting subsidiary operates, also referred to as its functional 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 denominated or measured in a different local functional currency, for example the Canadian dollar for a Canadian subsidiary. We translate the assets and liabilities of each of our consolidating 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 partners' capital equity accounts are translated by using historical exchange rates. Translation adjustments result from translating all assets and liabilities at current year-end rates, while partners' capital equity is translated by using historical and weighted-average rates. The cumulative translation adjustments balance is reported as a component of "Accumulated other comprehensive income" within "Partners' Capital" in our consolidated balance sheets.

Comprehensive Income

For each of the years ended December 31, 2012, 2011 and 2010, the difference between our net income and our comprehensive income resulted from (i) unrealized gains or losses on derivative contracts utilized for hedging our exposure to fluctuating expected future cash flows produced by both energy commodity price risk and interest rate risk; (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.

Cumulative revenues, expenses, gains and losses that under U.S. generally accepted accounting principles are included within our comprehensive income but excluded from our earnings are reported as "Accumulated other comprehensive income" within "Partners' Capital" in our consolidated balance sheets. The following table summarizes changes in the amount of our "Accumulated other comprehensive income (loss)" in our accompanying consolidated balance sheets for each of the years ended December 31, 2012 and 2011 (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjs.	Total Accumulated other comprehensive income/(loss)
December 31, 2010	$ (308)	$ 132	$ (10)	$ (186)
Change for period	267	(44)	(34)	189
December 31, 2011	(41)	88	(44)	3
Change for period	107	44	9	160
December 31, 2012	$ 66	$ 132	$ (35)	$ 163

Limited Partners' Net Income per Unit

We compute Limited Partners' Net Income per Unit by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners' Net Income per Unit are made in accordance with the "Earnings per Share" Topic of the Codification.

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, natural gas liquids 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 specific hedge accounting criteria are met. If a derivative contract meets those criteria, the contract's gains and losses are allowed to offset related results on the hedged item in our income statement, and we are required to both 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 sale of natural gas, natural gas liquids and crude oil, and we have designated 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 transaction affects earnings. The ineffective portion of the gain or loss is reported in earnings immediately. See Note 13 for more information on our risk management activities and disclosures.

Accounting for Regulatory Activities

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. The amount of our regulatory assets and liabilities totaled $180 million and $21 million, respectively, as of December 31, 2012, and totaled $15 million and $12 million, respectively, as of December 31, 2011. We included the amounts of our regulatory assets and liabilities within “Other current assets,” “Deferred charges and other assets,” “Accrued other current liabilities” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheets as of December 31, 2012 and 2011. The overall increase in our total regulatory assets since December 31, 2011 was primarily due to a $113 million increase associated with an expected loss on TGP assets currently held for sale. We expect to recover this loss through TGP’s jurisdictional natural gas transportation rates. The recovery period for this regulatory asset is approximately 20 years.

3. Acquisitions and Divestitures

Business Combinations and Acquisitions of Investments

During 2012, 2011 and 2010, we completed the following significant acquisitions, and except for our acquisition of equity interests in Watco Companies, LLC and El Paso Midstream Investment Company, LLC (noted as (4), (8) and (9), respectively, in the table and discussion below), we accounted for these acquisitions in accordance with the “Business Combinations” Topic of the Codification. Accordingly, we (i) recorded all the acquired assets and assumed liabilities at their estimated fair market values as of the acquisition date; (ii) included the results of operations from these acquisitions in our consolidated financial statements from the acquisition date; and (iii) recognized “Goodwill” where applicable. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, goodwill is an intangible asset representing the future economic benefits expected to be derived from an acquisition that are not assigned to other identifiable, separately recognizable assets. We believe the primary items that generated our goodwill are both the value of the synergies created between the acquired assets and our pre-existing assets, and our expected ability to grow the business we acquired by leveraging our pre-existing business experience. Furthermore, we expect that the entire amount of our recorded goodwill will be deductible for tax purposes.

			Assignment of Purchase Price (in millions)				
Ref.	**Date**	**Acquisition**	**Purchase Price**	**Current Assets**	**Property Plant & Equipment**	**Deferred Charges & Other**	**Goodwill**
(1)	1/10	USD Terminal Acquisition	$ 201	$ 5	$ 43	$ 95	$ 58
(2)	3/10	Slay Industries Terminal Acquisition	102	—	68	33	1
(3)	5/10	KinderHawk Field Services LLC (1 of 2)	917	—	—	917	—
(4)	1/11	Watco Companies, LLC (1 of 2)	50	—	—	50	—
(5)	6/11	TGS Development, L.P. Terminal Acquisition	74	—	43	31	—
(6)	7/11	KinderHawk Field Services LLC and EagleHawk Field Services LLC (2 of 2)	912	36	642	140	94
(7)	11/11	SouthTex Treaters, Inc. Natural Gas Treating Assets	179	27	9	17	126
(8)	12/11	Watco Companies, LLC (2 of 2)	50	—	—	50	—
(9)	6/12	El Paso Midstream Investment Company, LLC	289	—	—	289	—

(1) USD Terminal Acquisition

On January 15, 2010, we acquired three ethanol handling train terminals from US Development Group LLC for an aggregate consideration of $201 million, consisting of $114 million in cash, $82 million in common units, and $5 million in assumed liabilities. The three train terminals are located in Linden, New Jersey; Baltimore, Maryland; and Euless, Texas. As part of the transaction, we announced the formation of a joint venture with US Development Group LLC to optimize and coordinate customer access to the three acquired terminals, other ethanol terminal assets we already own and operate, and other terminal projects currently under development by both parties. The acquisition complemented and expanded the ethanol and rail terminal operations we previously owned, and all of the acquired assets are included in our Terminals business segment.

(2) Slay Industries Terminal Acquisition

On March 5, 2010, we acquired certain bulk and liquids terminal assets from Slay Industries for an aggregate consideration of $102 million, consisting of $97 million in cash, assumed liabilities of $2 million, and an obligation to pay additional cash consideration of $3 million in years 2013 through 2019, contingent upon the purchased assets providing us an agreed-upon amount of earnings during the three years following the acquisition. Including accrued interest, we now expect to pay total contingent consideration of $2 million, including $1 million of this contingent consideration in the first half of 2013.

The acquired assets included (i) a marine terminal located in Sauget, Illinois; (ii) a transload liquid operation located in Muscatine, Iowa; (iii) a liquid bulk terminal located in St. Louis, Missouri; and (iv) a warehousing distribution center located in St. Louis. All of the acquired terminals have long-term contracts with large creditworthy shippers. As part of the transaction, we and Slay Industries entered into joint venture agreements at both the Kellogg Dock coal bulk terminal, located in Modoc, Illinois, and at the newly created North Cahokia terminal, located in Sauget and which has approximately 175 acres of land ready for development. All of the assets located in Sauget have access to the Mississippi River and are served by five rail carriers. The acquisition complemented and expanded our pre-existing Midwest terminal operations by adding a diverse mix of liquid and bulk capabilities, and all of the acquired assets are included in our Terminals business segment.

(3) KinderHawk Field Services LLC (1 of 2)

On May 21, 2010, we purchased a 50% ownership interest in Petrohawk Energy Corporation's natural gas gathering and treating business in the Haynesville shale gas formation located in northwest Louisiana for an aggregate consideration of $917 million in cash. During a short transition period, Petrohawk continued to operate the business, and effective October 1, 2010, a newly formed company named KinderHawk Field Services LLC, owned 50% by us and 50% by Petrohawk, assumed the joint venture operations. The acquisition complemented and expanded our existing natural gas gathering and treating businesses, and we assigned our entire purchase price to "Investments" (including $145 million of equity method goodwill, representing the excess of our investment cost over our proportionate share of the fair value of the joint venture's identifiable net assets).

On July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC and a 25% equity ownership interest in Petrohawk's natural gas gathering and treating business located in the Eagle Ford shale formation in South Texas. For more information about this acquisition, see "—(6) KinderHawk Field Services LLC and EagleHawk Field Services LLC (2 of 2)" below.

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

On January 3, 2011, we purchased 50,000 Class A preferred shares of Watco Companies, LLC for $50 million in cash in a private transaction. In connection with our purchase of these preferred shares, the most senior equity security of Watco, we entered into a limited liability company agreement with Watco that provides us certain priority and participating cash distribution and liquidation rights. Pursuant to the agreement, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and we participate 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 us certain approval rights, including the right to appoint one of the members to Watco's Board of Managers. On December 28, 2011, we made an additional $50 million investment in Watco, as described below in "—(8) Watco Companies, LLC (2 of 2)."

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

On June 10, 2011, we 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, we settled the $7 million liability by issuing additional common units to TGSD (we 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 New York Stock Exchange 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 our existing Gulf Coast bulk terminal facilities and expanded our pre-existing petroleum coke handling operations. All of the acquired assets are included as part of our Terminals business segment.

(6) KinderHawk Field Services LLC and EagleHawk Field Services LLC (2 of 2)

Effective July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC that we did not already own and a 25% equity ownership interest in 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). We then repaid the outstanding $154 million of borrowings and following this repayment, KinderHawk had no outstanding debt. The revolving bank credit facility was terminated at the time of such repayment.

Following our acquisition of the remaining ownership interest on July 1, 2011, we changed our method of accounting from the equity method to full consolidation, and due to the fact that we acquired a controlling financial interest in KinderHawk, we remeasured our previous 50% equity investment in KinderHawk to its fair value. We recognized a $167 million non-cash loss as a result of this remeasurement. The loss amount represents the excess of the carrying value of our 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 statements of income for the year ended December 31, 2011.

KinderHawk Field Services LLC gathers and treats natural gas in the Haynesville shale gas formation located in northwest Louisiana. Its assets currently consist of approximately 479 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. The system is designed to have approximately 2.0 billion cubic feet per day of pipeline capacity. Currently, it gathers approximately 1.0 billion cubic feet of natural gas per day. The Eagle Ford natural gas gathering joint venture is named EagleHawk Field Services LLC, and we account for our 25% investment under the equity method of accounting. A subsidiary of BHP Billiton (described below) operates EagleHawk Field Services LLC and owns the remaining 75% ownership interest. The joint venture owns two midstream gathering systems in and around Petrohawk's Hawkville and Black Hawk areas of Eagle Ford and combined, the joint venture's assets as of December 31, 2012 consist of more than 388 miles of gas gathering pipelines and approximately 266 miles of condensate gathering lines. It also has a life of lease dedication of Petrohawk's Eagle Ford reserves that provides Petrohawk and other Eagle Ford producers with gas and condensate gathering, treating and condensate stabilization services. All of the acquired assets are included in our Natural Gas Pipelines business segment.

Additionally, on August 25, 2011, mining and oil company BHP Billiton completed its previously announced acquisition of Petrohawk Energy Corporation 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 our contracts with Petrohawk.

(7) SouthTex Treaters, Inc. Asset Acquisition

On November 30, 2011, we 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 (carbon dioxide 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 our existing natural gas treating business, and all of the acquired operations are included in our Natural Gas Pipelines business segment.

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

On December 28, 2011, we 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 we acquired on January 3, 2011—we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and we participate partially in additional profit distributions at a rate equal to 0.5%.

Watco Companies, LLC is the largest privately held short line railroad company in the United States, operating 22 short line railroads on approximately 3,500 miles of leased and owned track. Our investment provided capital to Watco for further expansion of specific projects and complemented our existing terminal network. It also provides our customers more transportation services for many of the commodities that we currently handle, and offers us the opportunity to share in additional growth opportunities through new projects. As of December 31, 2012, our net equity investment in Watco totaled $103 million and is included within "Investments" on our accompanying consolidated balance sheet. We account for our investment under the equity method of accounting, and we include it in our Terminals business segment.

(9) El Paso Midstream Investment Company, LLC

Effective June 1, 2012, we 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, 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. We acquired our equity interest for an aggregate consideration of $289 million in common units (we issued 3,792,461 common units and determined each unit's value based on the $76.23 closing market price of the common units on the New York Stock Exchange on the June 4, 2012 issuance date). A subsidiary of KMI owns the remaining 50% interest in the joint venture.

We account for our investment under the equity method of accounting, and our investment and our pro rata share of the joint venture's operating results are included as part of our Natural Gas Pipelines business segment. As of December 31, 2012, our net equity investment in the joint venture totaled $312 million and is included within "Investments" on our accompanying consolidated balance sheet.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and accounted for as business combinations (including the acquisitions listed above) since January 1, 2011, as if they had occurred as of January 1, 2011, is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

August 2012 KMI Asset Drop-Down

As discussed above in Note 2, we acquired the drop-down asset group from KMI effective August 1, 2012. We acquired the drop-down asset group in order to replace the cash flows associated with the divested FTC Natural Gas Pipelines disposal group. Our consideration to KMI consisted of (i) $3.5 billion in cash; (ii) 4,667,575 common units (valued at $0.4 billion based on the $81.52 closing market price of the common units on the New York Stock Exchange on the August 13, 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). The terms of the drop-down transaction were approved on behalf of KMI by the independent members of its board of directors and on our behalf by the audit committees and the boards of directors of both our general partner and KMR, in its capacity as the delegate of our general partner, following the receipt by the independent directors of KMI and the audit committees of our general partner and KMR of separate fairness opinions from different independent financial advisors.

TGP is a 13,900 mile pipeline system with a transport design capacity of approximately 8.0 billion cubic feet per day of natural gas. It transports natural gas from Louisiana, the Gulf of Mexico and south Texas to the northeastern United States, including the metropolitan areas of New York City and Boston. EPNG is a 10,200 mile pipeline system with a design capacity of approximately 5.6 billion cubic feet per day of natural gas. It transports natural gas from the San Juan, Permian and Anadarko basins to California, other western states, Texas and northern Mexico.

The drop-down asset group is included in our Natural Gas Pipelines reportable business segment. We account for our 100% ownership interest in TGP under the full consolidation method and we account for our 50% investment in EPNG under the equity method of accounting. As of December 31, 2012, our net equity investment in EPNG totaled $872 million and is included within "Investments" on our accompanying consolidated balance sheet.

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the years ended December 31, 2012 and 2011, assumes that the drop-down transaction had occurred as of January 1, 2011. We prepared these unaudited pro forma financial results for comparative purposes only. These unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed the drop-down transaction as of January 1, 2011 or the results that will be attained in the future. Amounts presented below are in millions, except for per unit amounts:

	Pro Forma Year Ended December 31,	
	2012	2011
	(Unaudited)	
Revenues	$ 9,059	$ 8,865
Income from Continuing Operations	$ 1,996	$ 1,364
(Loss) Income from Discontinued Operations	$ (669)	$ 201
Net Income	$ 1,327	$ 1,565
Net Income Attributable to Noncontrolling Interests	$ (18)	$ (12)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 1,309	$ 1,553
Limited Partners' Net Income (Loss) per Unit:		
Income (Loss) from Continuing Operations	$ 1.43	$ 0.36
(Loss) Income from Discontinued Operations	(1.84)	0.59
Net (Loss) Income	$ (0.41)	$ 0.95

Acquisitions Subsequent to December 31, 2012

On January 29, 2013, we and Copano Energy, L.L.C., referred to in this report as Copano, announced a definitive agreement whereby we will acquire all of Copano's outstanding units, including convertible preferred units, for a total purchase price of approximately $5 billion, including the assumption of debt. The transaction, which has been approved by the board of directors of both our general partner and Copano, will be a 100% unit for unit transaction with an exchange ratio of 0.4563 of our common units for each Copano unit. The transaction is subject to customary closing conditions, regulatory approvals, and a vote of the Copano unitholders; however, TPG Advisors VI, Inc., Copano's largest unitholder, has agreed to support the transaction and we expect the transaction to close in the third quarter of 2013.

Copano is a midstream natural gas company that provides comprehensive services to natural gas producers, including natural gas gathering, processing, treating and natural gas liquids fractionation. Copano owns an interest in or operates approximately 6,900 miles of pipelines with 2.7 billion cubic feet per day of natural gas transportation capacity, and also owns nine natural gas processing plants with more than 1 billion cubic feet per day of natural gas processing capacity and 315 million cubic feet per day of natural gas treating capacity. Its operations are located primarily in Texas, Oklahoma and Wyoming. All of the acquired assets will be included in our Natural Gas Pipelines business segment.

Divestitures

FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

As described above in Note 2, following KMI's March 2012 agreement with the FTC, we began accounting for our FTC Natural Gas Pipelines disposal group as discontinued operations (prior to KMI's sale announcement, we included the disposal group in our Natural Gas Pipelines business segment). Additionally, during 2012, we remeasured the disposal group's net assets to reflect our assessment of fair value as a result of the FTC mandated sale requirement. Effective November 1, 2012, we then sold our FTC Natural Gas Pipelines disposal group to Tallgrass Energy Partners, LP, and we 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); however, KMI contributed to us $45 million to be used as partial funding for our cash selling expenses, and we recognized this contribution as an increase to our general partner's capital interest in us.

As a result of our remeasurement of net assets to fair value and the sale of net assets, we recognized a combined $829 million loss, and we reported this loss amount separately as "(Loss) on remeasurement to fair value and sale of FTC Natural Gas Pipelines disposal group" within the discontinued operations section of our accompanying consolidated statement of income for the year ended December 31, 2012. We reported the proceeds we 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.

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

	Year Ended December 31,(a)		
	2012	2011	2010
Operating revenues	$ 227	$ 322	$ 339
Operating expenses	(131)	(182)	(168)
Depreciation and amortization	(7)	(27)	(26)
Other expense	(1)	—	—
Earnings from equity investments	70	87	88
Interest income and Other, net	2	2	2
Income tax (expense)	—	(1)	—
Income from operations of FTC Natural Gas Pipelines disposal group	$ 160	$ 201	$ 235

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

Express Pipeline System

On December 11, 2012, we announced that we had entered into a definitive agreement to sell both our one-third equity ownership interest in the Express pipeline system and our subordinated debenture investment in Express to Spectra Energy Corp. for approximately $380 million (before tax). We acquired our equity ownership interest in the Express pipeline system from KMI effective August 28, 2008. The Express pipeline system is a common carrier, crude oil pipeline system comprised of the Express Pipeline and the Platte Pipeline, collectively referred to in this report as the Express pipeline system. The approximate 1,700-mile integrated oil transportation pipeline system connects Canadian and United States producers to refineries located in the U.S. Rocky Mountain and Midwest regions. The transaction is subject to customary consents and regulatory approvals and is expected to close in the second quarter of 2013. On this date, Spectra also announced that it will acquire the remaining ownership interests in Express, and following its acquisitions, will fully own the Express pipeline system.

We account for our equity investment in Express under the equity method of accounting and include its financial results within our Kinder Morgan Canada business segment. As of December 31, 2012, our (i) equity investment in the Express pipeline system totaled $65 million and our note receivable due from Express totaled $114 million. We included the combined $179 million amount within "Assets held for Sale" on our accompanying consolidated balance sheet.

Battleground Oil Specialty Terminal Company LLC

Effective December 1, 2012, TransMontaigne exercised its previously announced option to acquire up to 50% of our Class A member interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO), our 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 us for an aggregate consideration of $79 million, and following this acquisition, we now own a 55% Class A member interest in BOSTCO (we 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 we retained a controlling financial interest in BOSTCO, we accounted for this change in our ownership interest as an equity transaction; specifically, partners' capital attributable to us decreased by $5 million and the noncontrolling interest in BOSTCO increased by $84 million. We continue to account for our investment under the full consolidation method and as of December 31, 2012, construction continues on the approximately $430 million oil terminal joint venture.

4. Income Taxes

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

	Year Ended December 31,		
	2012	2011	2010
United States	$ 2,022	$ 1,033	$ 1,053
Foreign	33	79	73
Total Income from Continuing Operations Before Income Taxes.	$ 2,055	$ 1,112	$ 1,126

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,		
	2012	2011	2010
Taxes current expense:			
Federal	$ 17	$ 13	$ 5
State	10	16	10
Foreign	9	3	4
Total	36	32	19
Taxes deferred expense:			
Federal	—	(7)	5
State	—	(1)	—
Foreign	(6)	21	10
Total	(6)	13	15
Total tax provision	$ 30	$ 45	$ 34
Effective tax rate	1.5%	4.0%	3.0%

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows:

	Year Ended December 31,		
	2012	2011	2010
Federal income tax rate	35.0 %	35.0 %	35.0 %
Increase (decrease) as a result of:			
Partnership earnings not subject to tax	(35.0)%	(35.0)%	(35.0)%
Corporate subsidiary earnings subject to tax	— %	(0.8)%	(0.1)%
Income tax expense attributable to corporate equity earnings	0.9 %	1.5 %	0.9 %
Income tax expense attributable to foreign corporate earnings	0.1 %	2.1 %	1.3 %
State taxes	0.5 %	1.2 %	0.9 %
Effective tax rate	1.5 %	4.0 %	3.0 %

Our deferred tax assets and liabilities as of December 31, 2012 and 2011 resulted from the following (in millions):

	December 31,	
	2012	2011
Deferred tax assets:		
Book accruals	$ 2	$ —
Net Operating Loss/Tax credits	42	31
Other	18	3
Total deferred tax assets	62	34
Deferred tax liabilities:		
Property, plant and equipment	303	278
Other	8	6
Total deferred tax liabilities	311	284
Net deferred tax liabilities	$ 249	$ 250

We account for uncertainty in income taxes in accordance with the "Income Taxes" Topic of the Codification. Pursuant to these provisions, we must 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 on the past administrative practices and precedents of the taxing authority. The tax benefits recognized in our 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 beginning and ending gross unrecognized tax benefits (excluding interest and penalties) for each of the years ended December 31, 2012 and 2011 is as follows (in millions):

	Year Ended December 31,	
	2012	2011
Balance at beginning of period	$ 41	$ 33
Additions based on current year tax positions	17	8
Additions based on prior year tax positions	—	—
Reductions based on settlements with taxing authority	—	—
Reductions due to lapse in statute of limitations	(6)	—
Balance at end of period	$ 52	$ 41

Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense. During the year ended December 31, 2012, we recognized approximately $2 million in interest expense; during the year ended December 31, 2011, we recognized approximately $1 million in interest expense; and during the year ended December 31, 2010, we recognized reductions in interest expense of approximately $1 million.

As of December 31, 2012, (i) we had $4 million of accrued interest and no accrued penalties; (ii) we believe it is reasonably possible that our $52 million liability for unrecognized tax benefits will increase by approximately $9 million during the next twelve months; and (iii) we believe the full amount of $52 million of unrecognized tax benefits, if recognized, would favorably affect our effective income tax rate in future periods. As of December 31, 2011, we had $3 million of accrued interest and no accrued penalties. In addition, we have U.S. and state tax years open to examination for the periods 2007 through 2012.

5. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2012 and 2011, our property, plant and equipment consisted of the following (in millions):

Table of Contents

	December 31,	
	2012	2011
Natural gas, liquids, crude oil and carbon dioxide pipelines	$ 10,205	$ 7,759
Natural gas, liquids, carbon dioxide, and terminals station equipment	10,902	9,569
Natural gas, liquids (including linefill), and transmix processing	336	226
Other	1,656	1,454
Accumulated depreciation, depletion, and amortization	(5,758)	(4,980)
	17,341	14,028
Land and land right-of-way	921	770
Construction work in process	1,341	798
Property, plant and equipment, net	$ 19,603	$ 15,596

As of December 31, 2012 and 2011, we included regulated property, plant and equipment amounts of $5,162 million and $2,114 million, respectively, within "Property, plant and equipment, net" on our accompanying consolidated balance sheets. These regulated amounts constituted 26% and 14%, 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 $1,008 million in 2012, $887 million in 2011 and $853 million in 2010.

Asset Retirement Obligations

As of December 31, 2012 and 2011, we recognized asset retirement obligations in the aggregate amount of $157 million and $125 million, respectively. The majority of our asset retirement obligations are associated with our CO_2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. We included $11 million and $11 million, respectively, of our total asset retirement obligations as of December 31, 2012 and 2011 within "Accrued 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, 2012 and 2011, our investments consisted of the following (in millions):

	December 31,	
	2012	2011
El Paso Natural Gas Company, L.L.C.	$ 872	$ —
Midcontinent Express Pipeline LLC	633	667
El Paso Midstream Investment Company, LLC	312	—
Plantation Pipe Line Company	181	185
Red Cedar Gathering Company	172	168
Fayetteville Express Pipeline LLC	159	173
EagleHawk Field Services LLC	208	141
Eagle Ford Gathering LLC	151	117
Watco Companies, LLC	103	102
Express pipeline system	—	65
Cortez Pipeline Company	11	10
Rockies Express Pipeline LLC	—	1,595
All others	238	115
Total equity investments	3,040	3,338
Bond investments	8	8
Total investments	$ 3,048	$ 3,346

The overall change in the carrying amount of our equity investments since December 31, 2011 included (i) increases from both our June 1, 2012 acquisition of a 50% ownership interest in El Paso Midstream Investment Company, LLC and our August 1, 2012 acquisition of a 50% ownership interest in El Paso Natural Gas Company, L.L.C.; (ii) a decrease from our November 1, 2012 divestiture of a 50% ownership interest in Rockies Express Pipeline LLC; and (iii) a decrease from our December 11, 2012 announcement to sell our 33 1/3% ownership interest in the Express pipeline system (as of December 31, 2012, our equity investment in Express totaled $65 million and we included this amount within "Assets held for Sale" on our accompanying consolidated balance sheet). For further information pertaining to these acquisitions, divestiture, and announced divestiture, see Note 3.

As shown in the table above, our remaining significant equity investments (excluding the four investments described above and in Note 3) as of December 31, 2012 consisted of the following:

- Midcontinent Express Pipeline LLC—we operate and own a 50% ownership interest in Midcontinent Express Pipeline LLC. It is the sole owner of the Midcontinent Express natural gas pipeline system. The remaining ownership interest in Midcontinent Express Pipeline LLC is owned by subsidiaries of Regency Energy Partners, L.P. (50%);

- Plantation Pipe Line Company—we operate and own a 51.17% ownership interest in Plantation Pipe Line Company, 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, we do not control Plantation Pipe Line Company, and we account for our investment under the equity method;

- Red Cedar Gathering Company—we own a 49% ownership interest in the Red Cedar Gathering Company. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar is the sole owner of the Red Cedar natural gas gathering, compression and treating system;

- Fayetteville Express Pipeline LLC—we own a 50% ownership 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;

- EagleHawk Field Services LLC—we own a 25% ownership interest in EagleHawk Field Services LLC. A subsidiary of BHP Billiton operates EagleHawk Field Services LLC and owns the remaining 75% ownership interest;

- Eagle Ford Gathering LLC—we own a 50% member interest in Eagle Ford Gathering LLC. Copano Energy, L.L.C. owns the remaining 50% interest and serves as operator and managing member of Eagle Ford Gathering LLC;

- Watco Companies, LLC—we hold a preferred equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the United States. We own 100,000 Class A preferred shares and pursuant to the terms of our investment, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and we participate 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 us certain approval rights, including the right to appoint one of the members to Watco's Board of Managers; and

- Cortez Pipeline Company—we operate and own a 50% ownership 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% ownership interest and Cortez Vickers Pipeline Company owns the remaining 13% ownership interest.

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

	Year Ended December 31,		
	2012	2011	2010
Plantation Pipe Line Company	$ 51	$ 45	$ 30
Midcontinent Express Pipeline LLC	42	43	30
Red Cedar Gathering Company	32	32	29
Cortez Pipeline Company	25	24	23
Fayetteville Express Pipeline LLC	55	24	—
El Paso Natural Gas Company, L.L.C.	31	—	—
KinderHawk Field Services LLC	—	22	19
Eagle Ford Gathering LLC	34	11	—
Watco Companies, LLC	13	6	—
El Paso Midstream Investment Company, LLC	13	—	—
EagleHawk Field Services LLC	11	3	—
Express pipeline system	5	(2)	(3)
All others	27	16	8
Total	$ 339	$ 224	$ 136
Amortization of excess costs	$ (7)	$ (7)	$ (6)

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

	Year Ended December 31,		
Income Statement	**2012**	**2011**	**2010**
Revenues	$ 2,842	$ 2,313	$ 1,572
Costs and expenses	2,123	1,747	1,156
Earnings before extraordinary items and cumulative effect of a change in accounting principle	719	566	416
Net income	$ 719	$ 566	$ 416

Balance Sheet	December 31, 2012	2011
Current assets	$ 575	$ 491
Non-current assets	$ 9,805	$ 11,489
Current liabilities	$ 1,245	$ 546
Non-current liabilities	$ 3,624	$ 5,312
Partners'/Owners' equity	$ 5,511	$ 6,122

For information on regulatory matters affecting certain of our equity investments, see Note 17.

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 six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes, but combined with Products Pipelines for presentation in the table below); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2012 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 8.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell 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, 2012 and 2011, are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$ 263	$ 337	$ 46	$ 338	$ 627	$ 1,611
Accumulated impairment losses(a)	—	—	—	—	(377)	(377)
Balance as of December 31, 2010	263	337	46	338	250	1,234
Acquisitions(b)	—	220	—	—	—	220
Disposals(c)	—	—	—	(12)	—	(12)
Currency translation adjustments	—	—	—	—	(6)	(6)
Balance as of December 31, 2011	263	557	46	326	244	1,436
Acquisitions(d)	—	3,250	—	—	—	3,250
Disposals(e)	—	(85)	—	—	—	(85)
Currency translation adjustments	—	—	—	—	5	5
Balance as of December 31, 2012	$ 263	$ 3,722	$ 46	$ 326	$ 249	$ 4,606

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(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of U.S. generally accepted accounting principles, the consideration of this transaction caused KMI to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, KMI recorded a goodwill impairment charge of $377 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment is now included in our accumulated impairment losses. We have no other goodwill impairment losses.

(b) 2011 acquisition amount consists of (i) $126 million relating to our acquisition of natural gas treating assets from SouthTex Treaters, Inc. and (ii) $94 million relating to our purchase of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own (both discussed further in Note 3).

(c) 2011 disposal amount consists of (i) $11 million related to the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009 (see Note 11); and (ii) $1 million related to the sale of our subsidiary Arrow Terminals B.V.

(d) 2012 acquisition amount relates to acquisition of the drop-down asset group from KMI as discussed in Note 3.

(e) 2012 disposal amount relates to the sale of our FTC Natural Gas Pipelines disposal group as discussed in Note 3. Since our 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.

For more information on our accounting for goodwill, see Note 2 “Summary of Significant Accounting Policies—Goodwill.”

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 consolidating 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 $186 million and $193 million as of December 31, 2012 and 2011, 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, 2012, this excess investment cost is being amortized over a weighted average life of approximately twenty-six 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, 2012 and 2011. 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, 2012, 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, 2012 and 2011, these intangible assets totaled $1,095 million and $1,152 million, respectively, and primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

Primarily, these contracts, relationships and agreements related 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, 2012, 2011 and 2010, the amortization expense on our intangibles totaled $80 million, $61 million and $46 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2013 – 2017) is approximately $77 million, $74 million, $70 million, $66 million and $64 million, respectively. As of December 31, 2012, the weighted average amortization period for our intangible assets was approximately seventeen 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 and then amortize these costs as interest expense in our consolidated statements of income. The following table summarizes the net carrying value of our outstanding debt, excluding our debt fair value adjustments, as of December 31, 2012 and 2011 (in millions):

	December 31,	
	2012	2011
Current portion of debt(a)	$ 1,155	$ 1,638
Long-term portion of debt	14,714	11,183
Net carrying value of debt(b)	$ 15,869	$ 12,821

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(a) As of December 31, 2012 and 2011, includes commercial paper borrowings of $621 million and $645 million, respectively.

(b) Excludes debt fair value adjustments. As of December 31, 2012 and 2011, our "Debt fair value adjustments" increased our debt balances by $1,461 million and $1,055 million, respectively. In addition to normal adjustments associated with valuing our debt obligations equal to the present value of amounts to be paid determined at appropriate current interest rates, 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 "Risk Management—Fair Value of Derivative Contracts."

The following provides additional detail on our debt instruments, excluding debt fair value adjustments, as of December 31, 2012 and 2011 (in millions):

	December 31,	
	2012	2011
Kinder Morgan Energy Partners, L.P. borrowings:		
Senior notes, 3.45% through 9.00%, due 2013 through 2042(a)	$ 13,350	$ 12,050
Commercial paper borrowings(b)	621	645
Subsidiary borrowings (as obligor):		
Tennessee Gas Pipeline Company, L.L.C. - Notes, 7.00% through 8.375%, due 2016 through 2037(c)	1,790	—
International Marine Terminals - Plaquemines, LA Revenue Bonds due March 15, 2025(d)	40	40
Kinder Morgan Liquids Terminals LLC - N.J. Development Revenue Bonds due Jan. 15, 2018(e)	25	25
Kinder Morgan Operating L.P. "B" - Jackson-Union Cos. IL Revenue Bonds due April 1, 2024(f)	24	24
Other miscellaneous subsidiary debt	19	37
Less: Current portion of debt	(1,155)	(1,638)
Total long-term portion of debt	$ 14,714	$ 11,183

(a) All of our fixed rate senior notes provide that we may redeem the notes 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, 2012, our commercial paper program provides for the issuance of up to $2.2 billion of commercial paper. Our unsecured revolving credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of December 31, 2012 and 2011, the average interest rates on our outstanding commercial paper borrowings were 0.45% and 0.53%, respectively. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2012 and 2011, and in the near term, we expect that our short-term liquidity and financing needs will be met primarily through borrowings made under our commercial paper program.

(c) Consists of six separate series of fixed-rate unsecured senior notes that we assumed as part of the drop-down transaction.

(d) We own a 66 2/3% interest in the International Marine Terminals (IMT) partnership. The principal assets owned by IMT are dock and wharf facilities financed by the Plaquemines Port, Harbor and Terminal District (Louisiana) $40 million Adjustable Rate Annual Tender Port Facilities Revenue Refunding Bonds (International Marine Terminals Project) Series 1984A and 1984B. As of December 31, 2012, the interest rate on these bonds was 1.08%. The bonds are backed by two letters of credit issued by Wells Fargo. Our obligation, according to our ownership interests, is approximately $30 million for principal, plus interest and other fees.

(e) Economic Development Revenue Refunding Bonds issued by the New Jersey Economic Development Authority. As of December 31, 2012, the interest rate on these bonds was 0.15%. We have an outstanding letter of credit issued by Citibank in the amount of $25 million that backs-up the $25 million principal amount of the bonds.

(f) Tax exempt bonds issued by the Jackson-Union Counties Regional Port District, a political subdivision embracing the territories of Jackson County and Union County in the state of Illinois. These variable rate demand bonds bear interest at a weekly floating market rate and are backed-up by a letter of credit issued by Wells Fargo. The bond indenture also contains certain standby purchase agreement provisions which allow investors to put (sell) back their bonds at par plus accrued interest. As of December 31, 2012, the interest rate on these bonds was 0.15%. Our outstanding letter of credit issued by Wells Fargo totaled $24 million, which backs-up the principal amount of the bonds.

2012 Changes in Debt

Changes in our outstanding debt, excluding debt fair value adjustments, during the year ended December 31, 2012 are summarized as follows (in millions):

Debt borrowings	Interest rate	Increase / (decrease)	Cash received / (paid)
Issuances and Assumptions			
Senior notes due September 1, 2022(a)	3.95%	$ 1,000	$ 998
Senior notes due February 15, 2023(b)	3.45%	625	622
Senior notes due August 15, 2042(b)	5.00%	625	621
Commercial paper	variable	6,453	6,453
Bridge loan credit facility due February 6, 2013(c)	variable	576	576
Tennessee Gas Pipeline Company, L.L.C. - senior notes due February 1, 2016(d)	8.00%	250	—
Tennessee Gas Pipeline Company, L.L.C. - senior notes due April 4, 2017(d)	7.50%	300	—
Tennessee Gas Pipeline Company, L.L.C. - senior notes due March 15, 2027(d)	7.00%	300	—
Tennessee Gas Pipeline Company, L.L.C. - senior notes due October 15, 2028(d)	7.00%	400	—
Tennessee Gas Pipeline Company, L.L.C. - senior notes due June 15, 2032(d)	8.375%	240	—
Tennessee Gas Pipeline Company, L.L.C. - senior notes due April 1, 2037(d)	7.625%	300	—
Total increases in debt		$ 11,069	$ 9,270
Repayments and other			
Senior notes due March 15, 2012(a)	7.125%	$ (450)	$ (450)
Senior notes due September 15, 2012(e)	5.85%	(500)	(500)
Commercial paper	variable	(6,476)	(6,476)
Bridge loan credit facility due February 6, 2013(c)	variable	(576)	(576)
Kinder Morgan Texas Pipeline, L.P. - senior notes due January 2, 2014	5.23%	(8)	(8)
Kinder Morgan Arrow Terminals L.P. - note due April 4, 2014	6.0%	(1)	(1)
Kinder Morgan Operating L.P. “A” - BP note due March 31, 2012	5.40%	(5)	—
Kinder Morgan Canada Company - BP note due March 31, 2012	5.40%	(5)	—
Total decreases in debt		$ (8,021)	$ (8,011)

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(a) Represents senior notes issued in a public offering completed on March 14, 2012. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of $994 million, and we used the proceeds both to repay our $450 million of 7.125% senior notes that matured on March 15, 2012 and to reduce the borrowings under our commercial paper program.

(b) Represents senior notes issued in a public offering completed on August 13, 2012. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of $1,236 million, and we used the proceeds to pay a portion of the purchase price for the drop-down transaction.

(c) On August 6, 2012, we entered into a second credit agreement with us as borrower; Wells Fargo Bank, National Association, as administrative agent; Barclays Bank PLC, as syndication agent; and a syndicate of other lenders. This credit agreement provided for borrowings up to $2.0 billion pursuant to a short-term bridge loan credit facility with a term of six months. The covenants of this facility were substantially similar to the covenants of our existing senior unsecured revolving credit facility that is due July 1, 2016, and similar to our existing credit facility, borrowings under this bridge loan credit facility could be used to back our commercial paper issuances and for other general partnership purposes (including to pay a portion of the purchase price for the drop-down transaction). In August 2012, we made borrowings of $576 million under our short-term bridge loan credit facility to pay a portion of the purchase price for the drop-down transaction. We then repaid these credit facility borrowings in August 2012 with incremental borrowings under our commercial paper program, and we terminated our bridge loan credit facility on November 16, 2012. At this time, we also repaid the incremental commercial paper borrowings with the net proceeds we received from the disposal of our FTC Natural Gas Pipelines disposal group.

(d) Our subsidiary, Tennessee Gas Pipeline Company, L.L.C. is the obligor of six separate series of fixed-rate unsecured senior notes having a combined principal amount of $1,790 million. We assumed these debt borrowings as part of the drop-down transaction.

(e) On September 15, 2012, we paid $500 million to retire the principal amount of our 5.85% senior notes that matured on that date. We borrowed the necessary funds under our commercial paper program. Also, on March 15, 2011, we paid $700 million to retire the principal amount of our 6.75% senior notes that matured on that date. We used both cash on hand and borrowings under our commercial paper program to repay the maturing senior notes.

2011 Debt Issuances and Retirements

During 2011, we completed two separate public offerings of senior notes. With regard to these offerings, we received proceeds, net of underwriter discounts, as follows: (i) $1,093 million from a March 14, 2011 public offering of a total of $1.1 billion in principal amount of senior notes, consisting of $500 million of 3.50% notes due March 1, 2016 and $600 million of 6.375% notes due March 1, 2041; and (ii) $743 million from an August 17, 2011 public offering of a total of $750 million in principal amount of senior notes, consisting of $375 million of 4.15% notes due March 1, 2022 and $375 million of 5.625% notes due September 1, 2041. We used the proceeds from all of our 2011 debt offerings to reduce the borrowings under our commercial paper program.

On March 15, 2011, we paid $700 million to retire the principal amount of our 6.75% senior notes that matured on that date. We used both cash on hand and borrowings under our commercial paper program to repay the maturing senior notes.

Credit Facility and Restrictive Covenants

On July 1, 2011, we amended our $2.0 billion three-year senior unsecured revolving credit facility to, among other things, (i) allow for borrowings of up to $2.2 billion; (ii) extend the maturity of the credit facility from June 23, 2013 to July 1, 2016; (iii) permit an amendment to allow for borrowings of up to $2.5 billion; and (iv) decrease the interest rates and commitment fees for borrowings under this facility. The credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit facility can be used for general partnership purposes and as a backup for our commercial paper program. There were no borrowings under the credit facility as of December 31, 2012 or as of December 31, 2011.

As of December 31, 2012, the amount available for borrowing under our credit facility was reduced by a combined amount of $841 million, consisting of $621 million of commercial paper borrowings and $220 million of letters of credit, consisting of (i) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $85 million in three letters of credit that support tax-exempt bonds; (iii) a $12 million letter of credit that supports debt securities issued by the Express pipeline system; and (iv) a combined $23 million in other letters of credit supporting other obligations of us and our subsidiaries.

Interest on our credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt. Additionally, the credit facility included the following restrictive covenants as of December 31, 2012:

- 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 we make 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 our credit facility, the occurrence at any time of any of the following would constitute an event of default (i) our 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) our 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 us 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 our liquidation, reorganization or any other similar relief under any federal, state or foreign bankruptcy, insolvency, receivership or similar law.

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

Maturities of Debt

The scheduled maturities of our outstanding debt, excluding the value of interest rate swaps, as of December 31, 2012, are summarized as follows (in millions):

Year	Commitment
2013	$ 1,155
2014	501
2015	300
2016	750
2017	900
Thereafter	12,263
Total	$ 15,869

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 4.24% during 2012 and 4.26% during 2011. Information on our interest rate swaps is contained in Note 13 "Risk Management—Interest Rate Risk Management." For information about our contingent debt agreements, see Note 12 "Commitments and Contingent Liabilities—Contingent Debt."

9. Employee Benefits

Pension and Other Postretirement Benefit Plans

Two of our subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension plans for eligible Trans Mountain pipeline system employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements (which provide pension benefits in excess of statutory limits), and defined contributory plans. These subsidiaries also provide postretirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and other postretirement benefit plans for 2012, 2011 and 2010 were $11 million, $7 million and $4 million, respectively, recognized ratably over each year. As of December 31, 2012, we estimate our overall net periodic pension and other postretirement benefit costs for these plans for 2013 will be approximately $12 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. Furthermore, we expect to contribute approximately $12 million to these benefit plans in 2013.

Our subsidiary, TGP, also provides postretirement benefits other than pensions for certain retired employees. The costs for this plan are prefunded to the extent such costs are recoverable through natural gas pipeline transportation rates. Our combined net periodic benefit costs for the TGP other postretirement benefit plan for 2012 was a credit (increase to income) of $2 million, recognized ratably over the seven months we included TGP in our consolidated results. As of December 31, 2012, we estimate our overall net periodic other postretirement benefit cost for this plan for 2013 will be a credit of approximately $3 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. Furthermore, we expect to make no contributions to this benefit plan in 2013.

Additionally, our subsidiary SFPP, L.P. 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, L.P. postretirement benefit plan are not material to our consolidated income statements or balance sheets.

As of December 31, 2012 and 2011, the recorded value of our benefit liabilities for all of our pension and other .postretirement benefit plans was a combined $74 million and $70 million, respectively. As of December 31, 2012, the TGP other postretirement benefit plan was overfunded by $32 million. We consider our overall pension and other postretirement benefit liability exposure and the fair value of our pension and other postretirement plan assets to be minimal in relation to the value of our total consolidated assets and net income.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily our acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, we participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans for each of the years ended December 31, 2012, 2011 and 2010 were $11 million, $12 million and $10 million, respectively. We consider our overall multi-employer pension plan liability exposure to be minimal in relation to the value of our total consolidated assets and net income.

Kinder Morgan Savings Plan

The Kinder Morgan Savings Plan is a defined contribution 401(k) plan. The Savings Plan permits all full-time employees of KMI and KMGP Services Company, Inc. to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. Currently, our general partner contributes an amount equal to 5% of base compensation per year for most plan participants. However, for certain plan participants, employee contributions and general partner contributions are based on collective bargaining agreements. Plan assets are held and distributed pursuant to a trust agreement. The total amount charged to expense for the Kinder Morgan Savings Plan was $16 million during 2012, $17 million during 2011, and $13 million during 2010.

Cash Balance Retirement Plan

Employees of KMGP Services Company, Inc. and KMI are also eligible to participate in a Cash Balance Retirement Plan. Certain employees continue to accrue benefits through a career-pay formula ("grandfathered" according to age and years of service on December 31, 2000), or collective bargaining arrangements. All other employees accrue benefits through a personal retirement account in the Cash Balance Retirement Plan. Under the plan, KMI credits each participating employee's personal retirement account an amount equal to a percentage of eligible compensation every pay period. Currently, KMI contributes a percentage of eligible compensation equal to (i) 4%, for participants having a combined age and years of eligible service as of December of the prior year of less than 50; or (ii) 5%, for participants having a combined age and years of eligible service as of December of the prior year equal to or greater than 50. Effective January 1, 2013, KMI amended the plan and began crediting contribution amounts equal to 4% or 5% of eligible compensation every pay period to each participating employee's personal retirement account. Prior to this amendment, KMI credited 3% of employees' eligible compensation to their personal retirement accounts. Employees become fully vested in the plan after three years, and they may take a lump sum distribution upon termination of employment or retirement.

In addition, interest is credited to the personal retirement accounts at a rate equal to the five-year U.S. Treasury note rate plus 0.25% since January 1, 2011. Prior to January 1, 2011, interest was credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. This interest rate credit change allows KMI to invest the plan's assets in a manner that preserves capital and controls volatility. Furthermore, the revised interest rate complies with the safe harbor regulations as defined by the U.S. Department of Labor and is expected to reduce the plan's long-term cost.

10. Partners' Capital

Limited Partner Units

As of December 31, 2012 and 2011, our partners' capital included the following limited partner units:

	December 31,	
	2012	2011
Common units:		
Held by third parties	231,718,422	216,306,794
Held by KMI and affiliates (excluding our general partner)	19,314,003	14,646,428
Held by our general partner	1,724,000	1,724,000
Total common units	252,756,425	232,677,222
Class B units(a)	5,313,400	5,313,400
i-units(b)	115,118,338	98,509,392
Total limited partner units	373,188,163	336,500,014

(a) As of both December 31, 2012 and December 31, 2011, all of our Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange

(b) As of both December 31, 2012 and 2011, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. In accordance with its limited liability company agreement, KMR's activities are restricted to being a limited partner in us, and to controlling and managing our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Through the combined effect of the provisions in our partnership agreement and the provisions of KMR's limited liability company agreement, the number of outstanding KMR shares and the number of our i-units will at all times be equal.

The total limited partner units represent our limited partners' interest and an effective 98% interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its right to receive incentive distributions.

Equity Issuances

2012 Issuances

On February 27, 2012, we entered into a third amended and restated equity distribution agreement with UBS Securities LLC (UBS) which increased the aggregate offering price of our common units to up to $1.9 billion (up from $1.2 billion). During the year ended December 31, 2012, we issued 6,932,576 of our common units pursuant to our equity distribution agreement with UBS. We received net proceeds of $560 million from the issuance of these common units and we used the proceeds to reduce the borrowings under our commercial paper program.

Sales of common units pursuant to our equity distribution agreement are made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we also may sell common units to UBS as principal for its own account at a price agreed upon at the time of the sale. Any sale of common units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS.

Our equity distribution agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through UBS, on a daily basis or otherwise as we and UBS agree. UBS will then use its reasonable efforts to sell, as our sales agent and on our behalf, all of the designated common units. We may instruct UBS not to sell common units if the sales cannot be effected at or above the price designated by us in any such instruction. Either we or UBS may suspend the offering of common units pursuant to the agreement by notifying the other party.

For the year ended December 31, 2012, in addition to the issuance of common units pursuant to our equity distribution agreement, our significant equity issuances consisted of the following:

- on June 4, 2012, we issued 3,792,461 common units as our purchase price for the 50% equity ownership interest in El Paso Midstream Investment Company, LLC we acquired from KKR. For more information about this issuance, see Note

3 “Acquisitions and Divestitures—Business Combinations and Acquisitions of Investments—(9) El Paso Midstream Investment Company, LLC;”

- on August 13, 2012, in connection with the drop-down transaction, we issued 4,667,575 of our common units to KMI. We valued the units at $381 million, based on the $81.52 closing market price of the common units on the New York Stock Exchange on August 13, 2012. For more information on the drop-down transaction, see Note 3 “Acquisitions and Divestitures—August 2012 KMI Asset Drop-Down;”

- in the third quarter of 2012, KMR issued 10,120,000 of its shares in a public offering at a price of approximately $73.50 per share, less commissions and underwriting expenses. KMR used the net proceeds received from the issuance of these 10,120,000 shares to buy additional i-units from us, and we received net proceeds of $727 million. We used the proceeds to pay a portion of the purchase price for the drop-down transaction; and

- on December 14, 2012, we issued, in a public offering, 4,485,000 of our common units at a price of $78.60 per unit, less commissions and underwriting expenses. We received net proceeds, after deducting the underwriter discount, of $349 million for the issuance of these 4,485,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

2011 Issuances

In 2011, we issued 5,764,708 of our common units pursuant to our equity distribution agreement. We received net proceeds from the issuance of these common units of $421 million. We used the proceeds to reduce the borrowings under our commercial paper program.

In addition to the issuance of common units pursuant to our equity distribution agreement, we issued, in a public offering in June 2011, 7,705,000 of our common units at a price of $71.44 per unit, less commissions and underwriting expenses. We received net proceeds, after deducting the underwriter discount, of $534 million from the issuance of these 7,705,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

Adjustment to Partners’ Capital from August 2012 KMI Asset Drop-Down

We determined that the drop-down transaction constituted a transfer of net assets between entities under common control, and accordingly, we recognized the assets we acquired and the liabilities we assumed at KMI’s carrying value (including all purchase accounting adjustments from KMI’s acquisition of the drop-down asset group from EP effective May 25, 2012). We then recognized the difference between our purchase price and the carrying value of the assets acquired and liabilities assumed as an adjustment to our Partners’ Capital. As of December 31, 2012, the carrying value of the assets we acquired and the liabilities we assumed from the drop-down transaction totaled $6,361 million. We paid to KMI $3,482 million in cash, issued to KMI 4,667,575 common units valued at $381 million, and recognized a non-cash increase of $2,498 million in our Partners’ Capital. The increase to Partners’ Capital consisted of (i) a $2,472 million increase in our general partner’s 1% general partner capital interest in us; (ii) a $25 million increase in our general partner’s 1.0101% general partner capital interest in our subsidiary Kinder Morgan Operating L.P. “A” (a noncontrolling interest to us); and (iii) a $1 million increase in our “Accumulated other comprehensive income” (related to a small tax adjustment on the drop-down asset group’s deferred pension gains from periods prior to our acquisition of August 1, 2012).

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, 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 our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed, and we determine the allocation of incentive distributions to our general partner by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement.

The following table provides information about our distributions for the years ended December 31, 2012, 2011 and 2010 (in millions except per unit and i-Unit distributions amounts):

	Year Ended December 31,		
	2012	2011	2010
Per unit cash distribution declared	$ 4.98	$ 4.61	$ 4.40
Per unit cash distribution paid(a)	$ 4.85	$ 4.58	$ 4.32
Cash distributions paid to all partners(b)	$ 2,560	$ 2,243	$ 1,827
i-Unit distributions made to KMR(c)	6,488,946	6,601,402	6,369,724
General Partner's incentive distribution(d):			
Declared	$ 1,404	$ 1,174	$ 881
Paid(a)(e)	$ 1,322	$ 1,147	$ 848

____

(a) Distributions for the fourth quarter of each year are declared and paid during the first quarter of the following year. The year-to-year increases in distributions paid reflect the increase in amounts distributed per unit as well as the issuance of additional units; however, the overall increases in distributions paid in both 2012 versus 2011, and in 2011 versus 2010, were partially offset by decreases in the incentive distribution we paid to our general partner in both 2012 and 2011, as discussed below in note (d).

(b) Consisting of our common and Class B unitholders, our general partner and noncontrolling interests.

(c) Under the terms of our partnership agreement, we agreed that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as our i-units. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we will issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units. If additional units are distributed to the holders of our common units, we will issue an equivalent amount of i-units to KMR based on the number of i-units it owns. Based on the preceding, the i-units we distributed were based on the $4.85, $4.58 and $4.32 per unit paid to our common unitholders during 2012, 2011 and 2010, respectively.

(d) Incentive distribution does not include the general partner's initial 2% distribution of available cash.

(e) Our general partner's incentive distribution we paid in 2012, 2011 and 2010 was reduced by waived incentive amounts equal to $27 million, $28 million and $11 million, respectively, related to common units issued to finance a portion of our May 2010 and July 2011 KinderHawk Field Services LLC acquisitions. Beginning with our distribution payments for the quarterly period ended June 30, 2010, and ending with our distribution payments for the quarterly period ended March 31, 2013, our general partner has agreed not to take certain incentive distributions related to our acquisition of KinderHawk Field Services LLC. For more information about our KinderHawk acquisition, see Note 3 "Acquisitions and Divestitures—Business Combinations and Acquisitions of Investments—(3) KinderHawk Field Services LLC (1 of 2)" and "—(6) KinderHawk Field Services LLC and EagleHawk Field Services LLC (2 of 2)."

In addition, our general partner's incentive distribution we paid in 2010 was further affected by a reduced incentive amount of $168 million, due to a portion of our available cash distribution for the second quarter of 2010 being a distribution of cash from interim capital transactions, rather than a distribution of cash from operations (including the general partner's 2% general partner interest, its total cash distribution was reduced by $170 million). Our distribution of cash for the second quarter of 2010 (which we paid in the third quarter of 2010) from interim capital transactions totaled $177 million (approximately $0.56 per limited partner unit), and pursuant to the provisions of our partnership agreement, our general partner receives no incentive distribution on distributions of cash from interim capital transactions. Accordingly, this distribution from interim capital transactions helped preserve our cumulative excess cash coverage (cumulative excess cash coverage is cash from operations generated since our inception in excess of cash distributions paid).

In addition, there was practically no impact to our limited partners from this distribution of cash from interim capital transactions because (i) the cash distribution to our limited partners for the quarter did not change; (ii) fewer dollars in the aggregate were distributed (because there was no incentive distribution paid to our general partner related to the portion of the quarterly distribution that was a distribution of cash from interim capital transactions); and (iii) our general partner, in this instance, agreed to waive any resetting of the incentive distribution target levels, as would otherwise occur according to our partnership agreement.

For further information about our partnership distributions, see Note 11 "Related Party Transactions—Partnership Interests and Distributions."

Subsequent Events

On January 16, 2013, we declared a cash distribution of $1.29 per unit for the quarterly period ended December 31, 2012. This distribution was paid on February 14, 2013, to unitholders of record as of January 31, 2012. Since this distribution was declared after the end of the quarter, no amount is shown in our December 31, 2012 balance sheet as a distribution payable. Our common unitholders and our Class B unitholder received cash. KMR, our sole i-unitholder, received a distribution in the form of additional i-units based on the $1.29 distribution per common unit. The number of i-units distributed was 1,804,595. For each outstanding i-unit that KMR held, a fraction of an i-unit (0.015676) was issued. The fraction was determined by dividing:

- $1.29, the cash amount distributed per common unit

by

- $82.294, the average of KMR's limited liability shares' closing market prices from January 14-28, 2013, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

This February 14, 2013 distribution included an incentive distribution to our general partner in the amount of $384 million. This incentive distribution was affected by a waived incentive distribution amount equal to $7 million related to common units issued to finance a portion of our acquisition of the remaining 50% interest in KinderHawk effective July 1, 2011. In addition, our general partner has also agreed to waive incentive distribution amounts equal to $4 million for 2013 to support our July 2011 KinderHawk acquisition.

11. Related Party Transactions

General and Administrative Expenses

KMGP Services Company, Inc., a subsidiary of our general partner, provides employees and Kinder Morgan Services LLC, a wholly owned subsidiary of KMR, provides centralized payroll and employee benefits services to (i) us; (ii) our operating partnerships and subsidiaries; (iii) our general partner; and (iv) KMR (collectively referred to in this note as the Group). Employees of KMGP Services Company, Inc. are assigned to work for one or more members of the Group. The direct costs of all compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated and charged by Kinder Morgan Services LLC to the appropriate members of the Group, and the members of the Group reimburse Kinder Morgan Services LLC for their allocated shares of these direct costs. There is no profit or margin charged by Kinder Morgan Services LLC to the members of the Group. The administrative support necessary to implement these payroll and benefits services is provided by the human resource department of KMI, and the related administrative costs are allocated to members of the Group in accordance with existing expense allocation procedures.

The effect of these arrangements is that each member of the Group 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. Pursuant to our limited partnership agreement, we provide reimbursement for our share of these administrative costs and such reimbursements will be accounted for as described above. Additionally, we reimburse KMR with respect to costs incurred or allocated to KMR in accordance with our limited partnership agreement, the delegation of control agreement among our general partner, KMR, us and others, and KMR's limited liability company agreement.

The named executive officers of our general partner and KMR and other employees that provide management or services to both KMI and the Group are employed by KMI. Additionally, other KMI employees assist in the operation of certain of our assets (discussed below in "—Operations"). These employees' expenses are allocated without a profit component between KMI on the one hand, and the appropriate members of the Group, on the other hand.

Non-Cash Compensation and Severance Expenses

For accounting purposes, KMI was required to allocate to us a portion of the compensation expense incurred from (i) a May 2007 merger of its then wholly-owned subsidiary Kinder Morgan Kansas, Inc. and a wholly-owned subsidiary of Kinder Morgan Kansas, Inc.'s then parent, Knight Holdco LLC (Knight Holdco LLC was a private company owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of our general partner and Kinder Morgan Management, LLC, and this merger is referred to as the going-private transaction); (ii) a one-time special cash bonus payment that was paid to non-senior management employees in May 2011; and (iii) employee severance expense associated with the EP acquisition.

As a subsidiary of KMI, we were then required to recognize the allocated amounts as expense on our income statements, and accordingly, (i) for each of the years 2011 and 2010, we recognized non-cash compensation expense of $3 million and $5 million, respectively, due to certain going-private transaction expenses; and (ii) in 2011, we recognized non-cash compensation expense of $87 million associated with the special bonus payment to non-senior management employees. However, we did not have any obligation, nor did we pay any amounts related to this allocated compensation expense, and since we were not responsible for paying this expense, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet.

In addition, in 2012, KMI paid and then allocated to us $9 million of employee severance expense associated with its acquisition of EP on May 25, 2012 (the severance expense allocated to us was associated with the drop-down asset group we acquired from KMI effective August 1, 2012). However, we do not have any obligation, nor did we pay any amounts related to this allocated severance expense. Accordingly, we recognized $7 million of the amount allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet. The remaining $2 million of expense was included within our proportionate share of the equity earnings from our 50% ownership interest in both EPNG and Bear Creek Storage Company, LLC (a 50%-owned equity investee of our subsidiary TGP).

Partnership Interests and Distributions

General

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. Available Cash consists generally of all of our cash receipts, including cash received by our operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to noncontrolling interests.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to KMR, subject to the approval of our general partner in certain cases, to establish, maintain and adjust reserves for the proper conduct of our 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 our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Our general partner and owners of our common units and Class B units receive distributions in cash, while KMR, the sole owner of our i-units, receives distributions in additional i-units. We do not distribute cash to i-unit owners (KMR) but instead retain the cash for use in our business. However, the cash equivalent of distributions of i-units is treated as if it had actually been distributed for purposes of determining the distributions to our general partner. Each time we make a distribution, the number of i-units owned by KMR and the percentage of our total units owned by KMR increase automatically under the provisions of our partnership agreement.

Pursuant to our partnership agreement, distributions to 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 to our general partner.

Cash from Operations. Cash from operations generally refers to our cash balance on the date we commenced operations, plus all cash generated by the operation of our business, after deducting related cash 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 us 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 we 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 we retain this cash and use it in our business. To date, all of our available cash distributions, other than a $177 million distribution of cash from interim capital transactions for the second quarter of 2010 (paid in the third quarter of 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 us 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 holders of i-units in equivalent i-units; and

- 2% to our general partner, until we have distributed cash from this source in respect of a common unit outstanding since our 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 our general partner. With respect to the portion of our distribution of available cash for the second quarter of 2010 that was from interim capital transactions, our general partner waived this resetting of the distribution target levels.

Kinder Morgan G.P., Inc.

Kinder Morgan G.P., Inc. serves as our sole general partner. Pursuant to our partnership agreement, our general partner's interests represent a 1% ownership interest in us, and a direct 1.0101% ownership interest in each of our five operating partnerships. Collectively, our general partner owns an effective 2% interest in our operating partnerships, excluding incentive distributions rights as follows:

- its 1.0101% direct general partner ownership interest (accounted for as a noncontrolling interest in our consolidated financial statements); and

- its 0.9899% ownership interest indirectly owned via its 1% ownership interest in us.

As of December 31, 2012, our general partner owned 1,724,000 common units, representing approximately 0.46% of our outstanding limited partner units. For information on distributions paid to our general partner, see Note 10 "Partners' Capital—Income Allocation and Declared Distributions."

Kinder Morgan, Inc.

KMI remains the sole indirect common stockholder of our general partner. Also, as of December 31, 2012, KMI directly owned 16,920,363 common units, indirectly owned 5,313,400 Class B units and 4,117,640 common units through its consolidated affiliates (including our general partner), and owned 14,957,793 KMR shares, representing an indirect ownership interest of 14,957,793 i-units. Together, these units represented approximately 11.1% of our outstanding limited partner units.

Including both its general and limited partner interests in us, at the 2012 distribution level, KMI received approximately 51% of all quarterly distributions of available cash from us, with approximately 45% attributable to its general partner interest and the remaining 6% attributable to its limited partner interest. These percentages were impacted slightly due to the general partner's waiver of certain incentive distribution amounts, as described in Note 10 "Partners' Capital—Income Allocation and Declared Distributions."

Kinder Morgan Management, LLC

As of December 31, 2012, KMR, our general partner's delegate, remained the sole owner of our 115,118,335 i-units.

Asset Acquisitions and Sales

From time to time in the ordinary course of business, we buy and sell pipeline and related services from KMI and its subsidiaries. Such transactions are conducted in accordance with all applicable laws and regulations and on an arms' length basis consistent with our policies governing such transactions. In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; (ii) TransColorado Gas Transmission Company LLC from KMI in November 2004; and (iii) TGP and 50% of EPNG from KMI in August 2012, KMI agreed to indemnify us and our general partner with respect to approximately $3.8 billion of our debt. KMI would be obligated to perform under this indemnity only if we are unable, and/or our assets were insufficient, to satisfy our obligations.

KMI has also indemnified us and our general partner with respect to approximately $558 million for our proportionate 50% share of EPNG's debt. Because we account for our investment in EPNG under the equity method of accounting, we do not include its debt in the debt reported on our accompanying consolidated balance sheets.

Mr. C. Berdon Lawrence, a non-management director on the boards of our general partner and KMR until July 20, 2011, is also Chairman Emeritus of the Board of Kirby Corporation. On February 9, 2011, we sold a marine vessel to Kirby Corporation's subsidiary Kirby Inland Marine, L.P., and additionally, we and Kirby Inland Marine L.P. formed a joint venture named Greens Bayou Fleeting, LLC. Pursuant to the joint venture agreement, we sold our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009 to the joint venture for $4 million in cash and a 49% ownership interest in the joint venture. Kirby then made cash contributions to the joint venture in exchange for the remaining 51% ownership interest. In the first quarter of 2011, after final reconciliation and measurement of all of the net assets sold, we recognized a combined $2 million increase in income from the sale of these net assets, and additionally, the sale of our ownership interest resulted in an $11 million non-cash reduction in our goodwill (see Note 7).

Operations

Natural Gas Pipelines and Products Pipelines Business Segments

KMI (or its subsidiaries) operates and maintain for us the assets comprising our Natural Gas Pipelines business segment, as well as our Products Pipelines business segment's 50%-owned Cypress Pipeline (we sold a 50% ownership interest in the Cypress Pipeline on October 1, 2010). Pursuant to the applicable underlying agreements, we pay (reimburse) KMI for the actual corporate general and administrative expenses incurred in connection with the operation of these assets. The combined amounts paid to KMI for corporate general and administrative costs incurred were $88 million for 2012, $71 million for 2011 and $56 million for 2010. We believe the amounts paid to KMI for the services it provided each year fairly reflect the value of the services performed; however, due to the nature of the allocations, these reimbursements may not exactly match the actual time and overhead spent. We also reimburse KMI for operating and maintenance costs and capital expenditures incurred with respect to our assets.

We sold our ownership interest in Kinder Morgan NatGas Operator LLC as part of our divestiture of the FTC Natural Gas Pipelines disposal group effective November 1, 2012. Kinder Morgan NatGas Operator LLC operates the Rockies Express natural gas pipeline system pursuant to an operating agreement. Under this agreement, it is reimbursed for its costs and receives a management fee of 1%, based on Rockies Express' operating income, less all depreciation and amortization expenses. In the first ten months of 2012, and the full years of both 2011 and 2010, it received management fees of $5 million, $6 million and $5 million, respectively. Prior to its divestiture, Kinder Morgan NatGas Operator LLC also operated the Midcontinent Express pipeline system. The Midcontinent Express pipeline system is now operated by a subsidiary of KMI.

In addition, we purchase natural gas transportation and storage services from Natural Gas Pipeline Company of America LLC and certain affiliates, collectively referred to as NGPL. KMI owns a 20% ownership interest in NGPL and accounts for its investment under the equity method of accounting. Pursuant to the provisions of a 15-year operating agreement that was entered into in 2008, KMI continues to operate NGPL's assets. For each of the years 2012, 2011 and 2010, expenses related to NGPL totaled $5 million, $8 million and $8 million, respectively, and we included these expense amounts within the caption "Gas purchases and other costs of sales" in our accompanying consolidated statements of income.

CO_2 Business Segment

During 2010, Kinder Morgan Power Company, a subsidiary of KMI, operated and maintained for us the power plant we constructed at the SACROC oil field unit, located in the Permian Basin area of West Texas. The power plant provides nearly half of SACROC's current electricity needs, and pursuant to the contract, Kinder Morgan Power Company incurred the costs and expenses related to operating and maintaining the power plant for the production of electrical energy at the SACROC field. Our subsidiary Kinder Morgan Production Company fully reimbursed Kinder Morgan Power Company's expenses, including all agreed-upon labor costs. The amount paid to Kinder Morgan Power Company in 2010 for operating and maintaining the power plant was $8 million, and we believe the amount paid to Kinder Morgan Power Company for the services it provided fairly reflected the value of the services performed. Our operating contract with Kinder Morgan Power Company expired on December 31, 2010, and effective January 1, 2011, Kinder Morgan Production Company began operating the power plant.

Terminals Business Segment

For services in the ordinary course of Kirby Corporation's and our Terminals segment's businesses, Kirby Corporation received payments from our subsidiaries totaling $38,729 in 2011 and $39,828 in 2010. In turn, Kirby made payments of $44,615 to our subsidiaries in 2011.

Risk Management

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

Our commodity-related risk management activities are monitored by our risk management committee, which is a separately designated standing committee whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of business. Our risk management committee is charged with the review and enforcement of our management's risk management policy. The committee is comprised of 18 executive-level employees of KMI or KMGP Services Company, Inc. whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of our businesses. The committee is chaired by our President and is charged with the following three responsibilities: (i) establish and review risk limits consistent with our risk tolerance philosophy; (ii) recommend to the audit committee of our general partner's delegate any changes, modifications, or amendments to our risk management policy; and (iii) address and resolve any other high-level risk management issues.

For more information on our risk management activities see Note 13.

KM Insurance, Ltd.

KM Insurance, Ltd. is a Class 2 Bermuda insurance company and wholly-owned subsidiary of KMI. The sole business of KM Insurance is to issue policies for KMI and us to secure the deductible portion of our workers compensation, automobile liability, and general liability policies placed in the commercial insurance market. We accrue for the cost of insurance and include these costs within our related party general and administrative expenses. For each of the years 2012, 2011 and 2010, these expenses totaled $9 million.

Notes Receivable

Plantation Pipe Line Company

We and ExxonMobil have a term loan agreement covering a note receivable due from Plantation Pipe Line Company (Plantation). We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was $49 million as of December 31, 2012 and $50 million as of December 31, 2011. 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 our portion of the note) due on July 20, 2016. We included $1 million of our note receivable balance within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of both December 31, 2012 and December 31, 2011, and we included the remaining outstanding balance within "Notes receivable."

Express US Holdings LP

We own a 33 1/3% equity ownership interest in the Express pipeline system. We also hold a long-term investment in a C $114 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. The debenture (i) is denominated in Canadian dollars; (ii) is due in full on January 9, 2023; (iii) bears interest at the rate of 12.0% per annum; and (iv) provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year. As of December 31, 2012 and December 31, 2011, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $114 million and $112 million, respectively. We included the December 31, 2012 note balance within "Assets held for sale" (because we have entered into a definitive agreement to sell our debt investment in Express as discussed in Note 3 "Acquisitions and Divestitures—Divestitures—Express Pipeline System"). We included the December 31, 2011 note balance within "Notes receivable" on our accompanying consolidated balance sheets.

KMI and El Paso Corporation

At the time of KMI's acquisition of EP on May 25, 2012 (discussed in Note 1), TGP had a note receivable from EP, and during the second quarter of 2012, TGP received combined principal note repayments of approximately $44 million. Upon our acquisition of TGP from KMI on August 1, 2012 (as part of the drop-down transaction discussed in Note 2), we and KMI agreed that the remaining $466 million amount due on the note receivable would not be repaid. Accordingly, this amount was treated as a decrease in KMI's investment in TGP and us, and as a result, TGP no longer has a related party note receivable with either KMI or EP. However, because we have included the historical results of TGP as though the net assets had been transferred to us May 25, 2012, the $44 million repayment is now included within "Repayments from related party" on our consolidated statement of cash flows for the year ended December 31, 2012.

Other Receivables and Payables

As of December 31, 2012 and December 31, 2011, our related party receivables (other than the notes receivable discussed above in "—Notes Receivable") totaled $14 million and $26 million, respectively. The December 31, 2012 receivables amount consisted of (i) $12 million included within "Accounts, notes and interest receivable, net" on our accompanying consolidated balance sheet; and (ii) $2 million of natural gas imbalance receivables included within "Other current assets." The $12 million receivable amount primarily consisted of amounts due from the Express pipeline system. The $2 million natural gas imbalance receivable consisted of amounts due from Natural Gas Pipeline Company of America, a 20%-owned equity investee of KMI and referred to in this report as NGPL.

The December 31, 2011 receivables amount consisted of (i) $15 million included within "Accounts, notes and interest receivable, net" on our accompanying consolidated balance sheet; and (ii) $11 million of natural gas imbalance receivables included within "Other current assets." The $15 million amount receivable amount primarily consisted of amounts due from the Express pipeline system, NGPL, and KMI. The $11 million natural gas imbalance receivable consisted of amounts due from both NGPL and the Rockies Express pipeline system.

As of December 31, 2012 and December 31, 2011, our related party payables totaled $7 million and $1 million, respectively, and we included these amounts within "Accounts payable" on our accompanying consolidated balance sheets. The December 31, 2012 related party amount consisted primarily of amounts due to KMI. The December 31, 2011 related party payable consisted of an amount due to the noncontrolling partner of Globalplex Partners, a Louisiana joint venture owned 50% and controlled by us.

Additionally, we have agreed to guarantee certain KMI lease payments from 2013 through 2035. For more information about this guarantee, see "Note 12 Commitments and Contingent Liabilities—Contingent Lease Liabilities."

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a fiduciary duty to manage us in a manner beneficial to our unitholders. Our general partner owns all of KMR's voting securities and elects all of KMR's directors. KMI, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner, and the officers of KMI have fiduciary duties to manage KMI, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to the owners of KMI. Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us.

The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty. The partnership agreements also provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of KMI may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand.

12. Commitments and Contingent Liabilities

Leases

The table below depicts future gross minimum rental commitments under our operating leases as of December 31, 2012 (in millions):

Year	Commitment
2013	$ 54
2014	44
2015	39
2016	33
2017	29
Thereafter	79
Total minimum payments	$ 278

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to 36 years. Total lease and rental expenses for each of the years ended December 31, 2012, 2011 and 2010 were $81 million, $140 million and $64 million, respectively. The increase in our lease and rental expenses in 2011 compared to 2012 and 2010 was driven by a $70 million increase in expense associated with adjustments to our Pacific operations' rights-of-way liabilities. For more information about this expense, see Note 16 "Litigation, Environmental and Other Contingencies—Commercial Litigation Matters—Union Pacific Railroad Company Easements." The amount of capital leases included within "Property, Plant and Equipment, net" in our accompanying consolidated balance sheets as of December 31, 2012 and December 31, 2011 are not material to our consolidated balance sheets.

Directors' Unit Appreciation Rights Plan

On April 1, 2003, KMR's compensation committee established our Directors' Unit Appreciation Rights Plan. Pursuant to this plan, and on this date of adoption, each of KMR's then three non-employee directors was granted 7,500 common unit appreciation rights. In addition, 10,000 common unit appreciation rights were granted to each of KMR's then three non-employee directors on January 21, 2004, at the first meeting of the board in 2004. During the first board meeting of 2005, the plan was terminated and replaced by the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors (discussed following); however, all unexercised awards made under the plan remained outstanding.

Upon the exercise of unit appreciation rights, we would pay, within thirty days of the exercise date, the participant an amount of cash equal to the excess, if any, of the aggregate fair market value of the unit appreciation rights exercised as of the exercise date over the aggregate award price of the rights exercised. As of December 31, 2010, 17,500 unit appreciation rights had been granted, vested and remained outstanding. All of these unit appreciation rights were owned by Mr. Perry

Waughtal. In 2011, Mr. Waughtal exercised his 17,500 unit appreciation rights at an aggregate fair value of $81.86 per unit, and he received a cash amount of $671,200. Accordingly, as of December 31, 2011 and December 31, 2012, no unit appreciation rights remained outstanding.

Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors

On January 18, 2005, KMR's compensation committee established the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan. 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 our interests and the interests of our unitholders by aligning the compensation of the non-employee members of the board of directors of KMR with unitholders' interests. Further, since KMR's success is dependent on its operation and management of our business and our 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 plan 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.

The elections under this plan for 2012, 2011 and 2010 were made effective January 17, 2012, January 18, 2011 and January 20, 2010, respectively (the elections for 2013 were made effective January 15, 2013). Each annual election is evidenced by an agreement, the Common Unit Compensation Agreement, between us and each non-employee director, and this agreement contains the terms and conditions of each award. Pursuant to this agreement, all common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. Until the forfeiture restrictions lapse, common units issued under the plan may not be sold, assigned, transferred, exchanged, or pledged by a non-employee director. In the event the director's service as a director of KMR is terminated prior to the lapse of the forfeiture restriction either for cause, or voluntary resignation, each director will, for no consideration, forfeit to us all common units to the extent then subject to the forfeiture restrictions. Common units with respect to which forfeiture restrictions have lapsed cease to be subject to any forfeiture restrictions, and we will provide each director a certificate representing the units as to which the forfeiture restrictions have lapsed. In addition, each non-employee director has the right to receive distributions with respect to the common units awarded to him under the plan, to vote such common units and to enjoy all other unitholder rights, including during the period prior to the lapse of the forfeiture restrictions.

The number of common units to be issued to a non-employee director electing to receive the cash compensation in the form of common units will equal the amount of such cash compensation awarded, divided by the closing price of the common units on the New York Stock Exchange on the day the cash compensation is awarded (such price, the fair market value), rounded down to the nearest 50 common units. The common units will be issuable as specified in the Common Unit Compensation Agreement. A non-employee director electing to receive the cash compensation in the form of common units will receive cash equal to the difference between (i) the cash compensation awarded to such non-employee director and (ii) the number of common units to be issued to such non-employee director multiplied by the fair market value of a common unit. This cash payment is payable in four equal installments generally around March 31, June 30, September 30 and December 31 of the calendar year in which such cash compensation is awarded.

On January 20, 2010, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2010. Effective January 20, 2010, Mr. Hultquist and Mr. Waughtal elected to receive the full amount of their compensation in the form of cash only. Mr. Lawrence elected to receive compensation of $159,495 in the form of our common units and was issued 2,450 common units. His remaining compensation ($505) was paid in cash as described above. No other compensation was paid to the non-employee directors during 2010.

On January 18, 2011, each of KMR's then three non-employee directors was awarded cash compensation of $180,000 for board service during 2011. Effective January 18, 2011, Mr. Hultquist and Mr. Waughtal elected to receive the full amount of their compensation in the form of cash only. Mr. Lawrence elected to receive compensation of $176,964 in the form of our common units and was issued 2,450 common units. On July 20, 2011, Mr. Lawrence resigned from the KMR and Kinder Morgan G.P., Inc. boards of directors and was replaced by Mr. Ted A. Gardner. Mr. Lawrence received remaining compensation of $1,518 paid in cash during the first half of 2011 (amount equal to one-half of the difference between (i) his total cash compensation award and (ii) the value of cash compensation received in the form of our common units according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors). Mr. Gardner was awarded cash compensation of $90,000 for board service during 2011, and his compensation was paid in cash as described above. No other compensation was paid to the non-employee directors during 2011.

On January 17, 2012, each of KMR's three non-employee directors was awarded cash compensation of $180,000 for board service during 2012. Each of the non-employee directors elected to receive the full amount of their compensation in the form of cash only. No other compensation was paid to the non-employee directors during 2012.

On January 15, 2013, each of KMR's three non-employee directors was awarded cash compensation of $180,000 for board service during 2013. Each of the non-employee directors elected to receive the full amount of their compensation in the form of cash only. No other compensation will be paid to the non-employee directors during 2013.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. As of December 31, 2012, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $86 million. This amount primarily related to the debt obligations of our 50%-owned investee Cortez Pipeline Company (we are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt).

For additional information regarding our debt facilities see Note 8 "Debt."

Contingent Lease Liabilities

In addition, we have agreed to guarantee certain lease payments from 2013 through 2035 made by KMI to EPC Building, LLC, a wholly-owned subsidiary of KMI, related to Kinder Morgan's principal executive offices located at 1001 Louisiana Street in Houston, Texas. We would be required to perform under this guarantee only if KMI was unable to perform. During the term of this lease, the payments we guarantee increase from $26 million in 2013 to $38 million in 2035.

13. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids 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.

Energy Commodity Price Risk Management

As of December 31, 2012, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil	(21.7)	million barrels
Natural gas fixed price	(18.5)	billion cubic feet
Natural gas basis	(17.9)	billion cubic feet
Derivatives not designated as hedging contracts		
Natural gas fixed price	1.7	billion cubic feet
Natural gas basis	4.2	billion cubic feet

As of December 31, 2012, 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 2016.

Interest Rate Risk Management

As of December 31, 2012, we had a combined notional principal amount of $5,525 million of fixed-to-variable interest rate swap agreements, effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of London InterBank Offered Rate (LIBOR) plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of December 31, 2012, 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.

As of December 31, 2011, we had a combined notional principal amount of $5,325 million of fixed-to-variable interest rate swap agreements. In March 2012, (i) we entered into four additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of $500 million, effectively converting a portion of the interest expense associated with our 3.95% senior notes due September 1, 2022 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread; and (ii) two separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of $200 million and converting a portion of the interest expense associated with our 7.125% senior notes terminated upon the maturity of the associated notes. In addition, (i) in June 2012, we terminated an existing fixed-to-variable interest rate swap agreement having a notional amount of $100 million, and we received proceeds of $53 million from the early termination of this swap agreement; (ii) in August 2012, we entered into an additional fixed-to-variable interest rate swap agreement having a notional principal amount of $100 million, effectively converting a portion of the interest expense associated with our 3.45% senior notes due February 15, 2023 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread; and (iii) in September 2012, a fixed-to-variable interest rate swap agreement having a notional principal amount of $100 million and effectively converting a portion of the interest expense associated with our 5.85% senior notes terminated upon the maturity of the associated notes.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" in the respective sections of our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of December 31, 2012 and 2011 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
	Balance sheet location	December 31, 2012 Fair value	December 31, 2011 Fair value	December 31, 2012 Fair value	December 31, 2011 Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	$ 42	$ 66	$ (18)	$ (116)
	Non-current-Fair value of derivative contracts	40	39	(11)	(39)
Subtotal		82	105	(29)	(155)
Interest rate swap agreements	Current-Fair value of derivative contracts	9	3	—	—
	Non-current-Fair value of derivative contracts	594	593	(1)	—
Subtotal		603	596	(1)	—
Total		685	701	(30)	(155)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	4	3	(3)	(5)
	Non-current-Fair value of derivative contracts	—	—	(1)	—
Total		4	3	(4)	(5)
Total derivatives		$ 689	$ 704	$ (34)	$ (160)

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. These fair value adjustments to our debt balances included (i) increases of $602 million and $596 million at December 31, 2012 and December 31, 2011, respectively, associated with the offsetting entry for hedged debt; (ii) decreases of $30 million and $24 million at December 31, 2012 and December 31, 2011, respectively, associated with unamortized debt discount amounts; (iii) increases of $401 million at December 31, 2012 and no amounts at December 31, 2011 associated with fair value adjustments to our debt previously recorded in purchase accounting; and (iv) increases of $488 million and $483 million at December 31, 2012 and December 31, 2011, respectively, associated with unamortized premium from the termination of interest rate swap agreements. As of December 31, 2012, the weighted-average amortization period of the unamortized premium from the termination of the interest rate swaps was approximately 18 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, 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,	
		2012	2011
Interest rate swap agreements	Interest expense	$ 59	$ 520
Total		$ 59	$ 520
Fixed rate debt	Interest expense	$ (59)	$ (520)
Total		$ (59)	$ (520)

(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,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contracts	$ 117	$ 14	Revenues-Natural gas sales	$ 4	$ 3	Revenues-Natural gas sales	$ —	$ —
			Revenues-Product sales and other	(19)	(270)	Revenues-Product sales and other	(11)	5
			Gas purchases and other costs of sales	23	11	Gas purchases and other costs of sales	—	—
Total	$ 117	$ 14	Total	$ 8	$ (256)	Total	$ (11)	$ 5

(a) We expect to reclassify an approximate $32 million gain associated with energy commodity price risk management activities and included in our Partners' Capital as of December 31, 2012 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) No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, the amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred).

For each of the years ended December 31, 2012 and 2011, we recognized no material gain or loss in income from derivative contracts not designated as hedging contracts.

Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies 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 over-the-counter 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 principally 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.

The maximum potential exposure to credit losses on our derivative contracts as of December 31, 2012 was (in millions):

	Asset position
Interest rate swap agreements	$ 603
Energy commodity derivative contracts	86
Gross exposure	689
Netting agreement impact	(17)
Cash collateral held	—
Net exposure	$ 672

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, 2012 and December 31, 2011, we had no outstanding letters of credit supporting our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. As of December 31, 2012, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $5 million, and we reported this amount within "Other current assets" in our accompanying consolidated balance sheet. As of December 31, 2011, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling $10 million, and we reported this amount within "Accrued other current liabilities" in our accompanying consolidated balance sheet.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. As of December 31, 2012, we estimate that if our credit rating was downgraded one notch, we would be required to post no additional collateral to our counterparties. If we were downgraded two notches (that is, below investment grade), we would be required to post $7 million of additional collateral.

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, 2012 and December 31, 2011, based on the three levels established by the Codification. The fair values of our current and non-current asset and liability derivative contracts each reported separately as "Fair value of derivative contracts" in the respective sections of our accompanying consolidated balance sheets. The fair value measurements in the tables below do not include cash margin deposits made by us or our counterparties, which are reported within "Other current assets" and "Accrued other current liabilities," respectively, 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, 2012				
Energy commodity derivative contracts(a)	$ 86	$ 3	$ 76	$ 7
Interest rate swap agreements	$ 603	$ —	$ 603	$ —
As of December 31, 2011				
Energy commodity derivative contracts(a)	$ 108	$ 34	$ 47	$ 27
Interest rate swap agreements	$ 596	$ —	$ 596	$ —

	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, 2012				
Energy commodity derivative contracts(a)	$ (33)	$ (3)	$ (26)	$ (4)
Interest rate swap agreements	$ (1)	$ —	$ (1)	$ —
As of December 31, 2011				
Energy commodity derivative contracts(a)	$ (160)	$ (15)	$ (125)	$ (20)
Interest rate swap agreements	$ —	$ —	$ —	$ —

(a) Level 1 consists primarily of the New York Mercantile Exchange (NYMEX) natural gas futures. Level 2 consists primarily of over-the-counter (OTC) West Texas Intermediate swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of West Texas Intermediate options.

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, 2012 and 2011 (in millions):

Significant unobservable inputs (Level 3)

	Year Ended December 31,	
	2012	2011
Derivatives-net asset (liability)		
Beginning of Period	$ 7	$ 19
Total gains or (losses):		
Included in earnings	(1)	(2)
Included in other comprehensive income	(1)	(12)
Purchases	3	5
Settlements	(5)	(3)
End of Period	$ 3	$ 7
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date	$ —	$ (2)

As of December 31, 2012, we reported our West Texas Intermediate options at fair value using Level 3 inputs due to such derivatives not having observable market prices. We determined the fair value of our West Texas Intermediate options using the Black Scholes option valuation methodology after giving consideration to a range of factors, including the prices at which the options were acquired, local market conditions, implied volatility, and trading values on public exchanges.

The significant unobservable input we use to measure the fair value of our Level 3 derivatives is implied volatility of options. We obtain the implied volatility of our West Texas Intermediate options from a third party service provider. As of December 31, 2012, this volatility ranged from 26% – 27% based on both historical market data and future estimates of market fluctuation. Significant increases (decreases) in this input 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 as of December 31, 2012 and 2011 (both short-term and long-term and including debt fair value adjustments), is disclosed below (in millions):

	December 31, 2012		December 31, 2011	
	Carrying Value	Estimated Fair value	Carrying Value	Estimated Fair value
Total debt	$ 17,330	$ 18,911	$ 13,876	$ 14,238

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2012 and December 31, 2011.

15. Reportable Segments

We divide our operations into five reportable business segments. These segments and their principal source of revenues are as follows:

- Products Pipelines— the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids;

- Natural Gas Pipelines—the sale, transport, processing, treating, storage and gathering of natural gas;

- CO_2—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;

- Terminals—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; and

- Kinder Morgan Canada—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States.

We evaluate performance principally based on each segment's earnings before depreciation, depletion and amortization expenses (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 maker organizes their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2012	**2011**	**2010**
Revenues			
Products Pipelines			
Revenues from external customers	$ 1,370	$ 914	$ 883
Intersegment revenues	—	—	—
Natural Gas Pipelines			
Revenues from external customers	3,926	3,943	4,078
Intersegment revenues	—	—	—
CO_2			
Revenues from external customers	1,677	1,416	1,246
Intersegment revenues	—	—	—
Terminals			
Revenues from external customers	1,358	1,314	1,264
Intersegment revenues	1	1	1
Kinder Morgan Canada			
Revenues from external customers	311	302	268
Intersegment revenues	—	—	—
Total segment revenues	8,643	7,890	7,740
Less: Total intersegment revenues	(1)	(1)	(1)
Total consolidated revenues	$ 8,642	$ 7,889	$ 7,739

(continued)

	Year Ended December 31,		
	2012	2011	2010
Operating expenses(a)			
Products Pipelines	$ 759	$ 500	$ 414
Natural Gas Pipelines	2,817	3,370	3,583
CO_2	381	342	309
Terminals	685	634	629
Kinder Morgan Canada	103	97	91
Total segment operating expenses	4,745	4,943	5,026
Less: Total intersegment operating expenses	(1)	(1)	(1)
Total consolidated operating expenses	$ 4,744	$ 4,942	$ 5,025
Other expense (income)			
Products Pipelines	$ (7)	$ (10)	$ 4
Natural Gas Pipelines	1	—	—
CO_2	(7)	—	—
Terminals	(15)	(1)	(4)
Kinder Morgan Canada	—	—	—
Total consolidated Other expense (income)	$ (28)	$ (11)	$ —
Depreciation, depletion and amortization			
Products Pipelines	$ 117	$ 105	$ 101
Natural Gas Pipelines	276	135	98
CO_2	439	437	453
Terminals	205	195	184
Kinder Morgan Canada	56	56	43
Total consolidated depreciation, depletion and amortization	$ 1,093	$ 928	$ 879
Earnings from equity investments			
Products Pipelines	$ 58	$ 51	$ 33
Natural Gas Pipelines	230	140	82
CO_2	25	24	23
Terminals	21	11	1
Kinder Morgan Canada	5	(2)	(3)
Total consolidated equity earnings.	$ 339	$ 224	$ 136
Amortization of excess cost of equity investments			
Products Pipelines	$ 4	$ 4	$ 4
Natural Gas Pipelines	1	1	—
CO_2	2	2	2
Terminals	—	—	—
Kinder Morgan Canada	—	—	—
Total consolidated amortization of excess cost of equity investments	$ 7	$ 7	$ 6

(continued)

	Year Ended December 31,		
	2012	2011	2010
Interest income			
Products Pipelines	$ 2	$ 3	$ 4
Natural Gas Pipelines	1	—	—
CO_2	—	1	2
Terminals	—	—	—
Kinder Morgan Canada	14	14	13
Total segment interest income	17	18	19
Unallocated interest income	6	3	1
Total consolidated interest income	$ 23	$ 21	$ 20
Other, net-income (expense)			
Products Pipelines	$ 9	$ 5	$ 12
Natural Gas Pipelines(b)	5	(164)	2
CO_2	(1)	4	2
Terminals	2	6	5
Kinder Morgan Canada	3	—	3
Total consolidated other, net-income (expense)	$ 18	$ (149)	$ 24
Income tax (expense) benefit			
Products Pipelines	$ (17)	$ (20)	$ (9)
Natural Gas Pipelines	5	(3)	(3)
CO_2	(5)	(4)	1
Terminals	(3)	5	(5)
Kinder Morgan Canada	(1)	(15)	(8)
Total segment income tax benefit (expense)	(21)	(37)	(24)
Unallocated income tax benefit (expense)	(9)	(8)	(10)
Total consolidated income tax benefit (expense)	$ (30)	$ (45)	$ (34)
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(c)			
Products Pipelines	$ 670	$ 463	$ 505
Natural Gas Pipelines(d)	1,349	546	576
CO_2	1,322	1,099	965
Terminals	709	704	641
Kinder Morgan Canada	229	202	182
Total segment earnings before DD&A	4,279	3,014	2,869
Total segment depreciation, depletion and amortization	(1,093)	(928)	(879)
Total segment amortization of excess cost of equity investments.	(7)	(7)	(6)
General and administrative expenses	(493)	(473)	(375)
Interest expense, net of unallocable interest income	(652)	(531)	(507)
Unallocable income tax expense	(9)	(8)	(10)
(Loss) income from discontinued operations(e)	(669)	201	235
Total consolidated net income	$ 1,356	$ 1,268	$ 1,327

Table of Contents

(continued)

	Year Ended December 31,		
	2012	2011	2010
Capital expenditures			
Products Pipelines	$ 307	$ 254	$ 145
Natural Gas Pipelines	323	153	138
CO_2	453	432	373
Terminals	707	332	326
Kinder Morgan Canada	16	28	22
Total consolidated capital expenditures	$ 1,806	$ 1,199	$ 1,004
Investments at December 31			
Products Pipelines	$ 268	$ 219	$ 216
Natural Gas Pipelines	2,589	2,887	3,563
CO_2	11	10	10
Terminals	179	164	27
Kinder Morgan Canada	1	66	70
Total consolidated investments	$ 3,048	$ 3,346	$ 3,886
Assets at December 31			
Products Pipelines	$ 4,921	$ 4,479	$ 4,369
Natural Gas Pipelines(d)	16,531	9,958	8,810
CO_2	2,337	2,147	2,141
Terminals	5,123	4,428	4,139
Kinder Morgan Canada	1,903	1,827	1,870
Total segment assets	30,815	22,839	21,329
Corporate assets(f)	1,279	1,264	532
Total consolidated assets	$ 32,094	$ 24,103	$ 21,861

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(a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) 2011 amount includes a $167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value (discussed further in Note 3).

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

(d) The increase in the 2012 amounts versus the 2011 amount reflects our acquisition of the drop-down asset group from KMI effective August 1, 2012 (discussed further in Note 3).

(e) Represents amounts from our FTC Natural Gas Pipelines disposal group. For further information, see Note 3.

(f) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to debt fair value adjustments.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2012, 2011 and 2010, we reported total consolidated interest expense of $658 million, $534 million and $508 million, respectively.

Our total operating revenues are derived from a wide customer base. For each of the years ended December 31, 2012, 2011 and 2010, no revenues from transactions with a single external customer amounted to 10% or more of our total consolidated revenues.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2012	2011	2010
Revenues from external customers			
United States	$ 8,220	$ 7,459	$ 7,363
Canada	407	411	356
Mexico and other(a)	15	19	20
Total consolidated revenues from external customers.	$ 8,642	$ 7,889	$ 7,739

Long-lived assets at December 31(b)	2012	2011	2010
United States	$ 22,016	$ 17,859	$ 16,929
Canada	2,011	1,843	1,909
Mexico and other(a)	74	76	86
Total consolidated long-lived assets	$ 24,101	$ 19,778	$ 18,924

(a) Includes operations in Mexico and until August 31, 2011, the Netherlands.

(b) Long-lived assets exclude (i) goodwill; (ii) other intangibles, net; and (iii) long-term note receivables from related parties.

16. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during 2012. This note also contains a description of any material legal proceedings that were initiated against us during 2012, and a description of any material events occurring subsequent to December 31, 2012 but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calnev Pipe Line LLC as Calnev; our 50%-owned equity investee El Paso Natural Gas Company, L.L.C. as EPNG; Chevron Products Company as Chevron; BP West Coast Products, LLC as BP; ConocoPhillips Company (now Phillips 66 Company) as Phillips 66; Tesoro Refining and Marketing Company as Tesoro; Western Refining Company, L.P. as Western Refining; Navajo Refining Company, L.L.C. as Navajo; Holly Refining & Marketing Company LLC (now HollyFrontier Refining & Marketing LLC) as HollyFrontier; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Southwest Airlines Co. as Southwest Airlines; Continental Airlines, Inc., Northwest Airlines, Inc. (now Delta Air Lines, Inc.), Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; Airlines for America as A4A; Ultramar Inc. as Ultramar; our subsidiary Tennessee Gas Pipeline Company, L.L.C. as TGP; our subsidiary Kinder Morgan CO_2 Company, L.P. (the successor to Shell CO_2 Company, Ltd.) as Kinder Morgan CO_2; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the American Railway Engineering and Maintenance-of-Way Association as AREMA; Severstal Sparrows Point, LLC as Severstal; RG Steel Sparrows Point LLC as RG Steel; the Texas Commission of Environmental Quality as the TCEQ; The Premcor Refining Group, Inc. as Premcor; Port Arthur Coker Company as PACC; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order as an NOPV; the federal Comprehensive Environmental Response, Compensation and Liability Act as CERCLA; the Interstate Commerce Act as the ICA; the United States Environmental Protection Agency as the U.S. EPA; the United States Environmental Protection Agency's Suspension and Debarment Division as the U.S. EPA SDD; the New Jersey Department of Environmental Protection as the NJDEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Liquids Terminals LLC as KMLT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. "OR" dockets designate FERC complaint proceedings, and "IS" dockets designate FERC protest proceedings.

__Federal Energy Regulatory Commission Proceedings__

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers regarding interstate rates on the pipeline systems listed below. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the ICA. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach 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: (i) whether "substantially changed circumstances" have occurred with respect to any "grandfathered" rates under the Energy Policy Act of 1992 such that those rates could be challenged; (ii) whether indexed rate increases are justified; and (iii) the appropriate level of return and income tax allowance we may include in our rates.

The following FERC dockets currently are pending:

- FERC Docket No. IS08-390 (West Line Rates) (Opinion Nos. 511 and 511-A)-Protestants: BP, ExxonMobil, Phillips 66, Valero Marketing, Chevron, the Airlines-Status: FERC order issued on December 16, 2011 (Opinion No. 511-A). While the order made certain findings that were adverse to SFPP, it ruled in favor of SFPP on many significant issues. SFPP made a compliance filing at the end of January 2012, and our rates reflect this filing. SFPP also filed a rehearing request on certain adverse rulings in the FERC order. Petitions for review of Opinion Nos. 511 and 511-A have been filed at the D.C. Circuit and are held in abeyance pending a ruling on SFPP's request for rehearing. It is not possible to predict the outcome of FERC review of the rehearing request or appellate review;

- FERC Docket No. IS09-437 (East Line Rates)-Protestants: BP, ExxonMobil, Phillips 66, Valero Marketing, Chevron, Western Refining, Navajo, HollyFrontier, and Southwest Airlines-Status: Opinion and Order on Initial Decision, Opinion No. 522, issued on September 20, 2012. The FERC generally made findings favorable to SFPP on significant issues and consistent with FERC's Opinion Nos. 511 and 511-A. SFPP and others filed requests for rehearing of Opinion No. 522 at FERC and petitions for review at the D.C. Circuit. The petitions for review are held in abeyance pending FERC action on the requests for rehearing. It is not possible to predict the outcome of FERC review of any request for rehearing or appellate review of this order. SFPP made a compliance filing in November 2012, and our rates reflect this filing;

- FERC Docket No. IS11-444 (2011 West Line Index Rate Increases)-Protestants: BP, ExxonMobil, Phillips 66, Valero Marketing, Chevron, the Airlines, Tesoro, Western Refining, Navajo, and HollyFrontier-Status: The shippers filed a motion for summary disposition that was granted in the shippers' favor in an initial decision issued on March 16, 2012. SFPP filed a brief with the FERC taking exception to the initial decision. The FERC will review the initial decision, and it is not possible to predict the outcome of FERC or appellate review;

- FERC Docket Nos. IS12-390 (East Line Index Rates)/IS12-388, IS12-500 and IS12-501 (West Line Index Rates)-Protestants: the Airlines, BP, Chevron, HollyFrontier, Phillips 66, Tesoro, Valero Marketing, and Western Refining-Status: Collectively, these shippers protested SFPP's index-based rate increases for its East Line (IS12-390) and West Line (IS12-388, IS12-500 and IS12-501). FERC rejected the protests against SFPP's East Line rate increases (IS12-390) and accepted the protests against SFPP's West Line rate increases (IS12-388). Following FERC acceptance of the West Line protests, SFPP withdrew these rate increases, reinstated the prior rates (IS12-500), and then subsequently increased its West Line rates by a smaller index-based percentage (IS12-501), which FERC accepted notwithstanding shipper protests. Shippers requested rehearing of FERC's acceptance of the East Line and West Line index rate increases in IS12-390 and IS12-501, and those requests are pending before FERC. It is not possible to predict the outcome of FERC review. FERC terminated the IS12-388/IS12-500 proceedings in July 2012;

- FERC Docket Nos. OR12-1, 12-2 and 12-3 (SFPP Index Ceiling Levels)-Complainants: Chevron, Tesoro and Phillips 66-Status: FERC dismissed the complaints on February 16, 2012.

- FERC Docket No. OR11-13 (Base Rates)—Complainant: Phillips 66—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Phillips 66 permitted to amend its complaint based on additional data;

- FERC Docket No. OR11-16 (Base Rates)—Complainant: Chevron—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Chevron permitted to amend its complaint based on additional data; and

- FERC Docket No. OR11-18 (Base Rates)—Complainant: Tesoro—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Tesoro permitted to amend its complaint based on additional data.

With respect to all of the SFPP proceedings above, 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 Opinion Nos. 511, 511-A, and 522, 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 our distributions to our limited partners.

Calnev

On March 17, 2011, the FERC issued an order consolidating and setting for hearing the complaints in Docket Nos. OR07-7, OR07-18, OR07-19, OR07-22, OR09-15, and OR09-20 filed by Tesoro, the Airlines, BP, Chevron, Phillips 66 and Valero Marketing. A settlement agreement resolving these proceedings was filed on February 24, 2012 and was certified to the FERC on March 1, 2012. On April 3, 2012, the FERC approved the settlement, and in May 2012, after the rates reduced by the settlement became effective, we made settlement payments of $54 million.

El Paso Natural Gas Company, L.L.C.

Docket No. RP08-426

In April 2010, the FERC approved an offer of settlement which increased EPNG's base tariff rates, effective January 1, 2009. The settlement resolved all but four issues in the proceeding. In January 2011, the presiding administrative law judge issued a decision that for the most part found against EPNG on those four issues. In May 2012, the FERC upheld the initial decision of the presiding administrative law judge in Opinion No. 517 on three of the issues and found in favor of EPNG on one of the issues. EPNG, along with other parties, has sought rehearing of those decisions to the FERC and may also seek review of any of the FERC's decisions to the U.S. Court of Appeals. However, in compliance with Opinion No. 517, EPNG filed with the FERC to implement certain aspects of the May 2012 order as they relate to rates under Docket No. RP08-426. Although the final outcome of all issues related to this open docket is not currently determinable, EPNG believes the accruals established for this matter are adequate.

Docket No. RP10-1398

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in base tariff rates which would increase revenues by approximately $100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Hearings were conducted during the fourth quarter of 2011 and in June 2012, the presiding administrative law judge issued an initial decision which was overall favorable for EPNG. The initial decision is currently being reviewed by the FERC. Participants may appeal this decision to the FERC and ultimately seek review of the FERC's decision to the U.S. Court of Appeals. Additionally, certain customers have requested that the FERC require EPNG to decrease its currently effective recourse rates based on an order issued in May 2012 for matters in Docket No. RP08-426. The FERC issued an order requiring the implementation of its decisions in Docket No. RP08-426, which included interim reductions to the currently effective rates. Although EPNG requested rehearing on the interim rate decrease, EPNG filed proforma tariff records to comply with the FERC's order and requested adequate surcharge authority in the event the final rates are above the interim rates. That rehearing request and filing currently are pending before the FERC. EPNG is pursuing settlement with its customers of all issues in both open rate cases. It is uncertain whether the expected increase in revenues will be achieved in the context of any such settlement or following the final determination of the FERC or the courts on the rate matters. Although the final outcome is not currently determinable, EPNG believes the accruals established for this matter are adequate.

California Public Utilities Commission Proceedings

We have 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

Table of Contents

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 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 we believe 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 has granted review with respect to SFPP's petition and the matter awaits scheduling of oral argument.

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.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately $375 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 and, potentially, the California Court of Appeals. We believe that the appropriate application of the income tax allowance and corrections of errors in law and fact should result in a considerably lower amount. We do not expect any reparations that we would pay in these matters to have an impact on our distributions to our limited partners.

Copano Shareholders' Litigation

Four putative class action lawsuits have been filed in connection with KMP's proposed merger with Copano. Two lawsuits have been filed in the District Court of Harris County, Texas: (i) Schultes v. Copano Energy, L.L.C., et al. (Case No. 06966), filed on February 5, 2013; and (ii) Bruen v. Copano Energy, L.L.C., et al. (Case No. 07076), filed on February 5, 2013. Two lawsuits have also been filed in the Court of Chancery of the State of Delaware: Berlin v. Copano Energy L.L.C., et al. (Case No. 8284-VCN), filed February 6, 2013; and Welzenbach v. William L. Thacker, et al. (Case No. 8317-VCN), filed on February 14, 2013.

Each of the actions names Copano, its board of directors, Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P. and Merger Sub as defendants. All three lawsuits are purportedly brought on behalf of a putative class seeking to enjoin the merger and alleging, 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, Kinder Morgan, Kinder Morgan G.P., Inc. and Merger Sub aided and abetted such alleged breaches.

Kinder Morgan and Copano have not yet responded to any of the complaints, but intend to vigorously defend these lawsuits.

Carbon Dioxide Tax Assessments

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to our subsidiary Kinder Morgan CO_2. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO_2 with respect to carbon dioxide produced from the McElmo Dome unit for tax years 2005, 2006, and 2007. The total amount of tax assessed was $6 million, plus interest of $1 million and penalties of $2 million. Kinder Morgan CO_2 protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO_2 is now awaiting the Colorado Department of Revenue's response to the protest.

Montezuma County, Colorado Property Tax Assessment

In November of 2009, the County Treasurer of Montezuma County, Colorado, issued to Kinder Morgan CO_2, as operator of the McElmo Dome unit, retroactive tax bills for tax year 2008, in the amount of $2 million. Of this amount, 37.2% is attributable to Kinder Morgan CO_2's interest. The retroactive tax bills were based on the assertion that a portion of the actual value of the carbon dioxide produced from the McElmo Dome unit was omitted from the 2008 tax roll due to an alleged overstatement of transportation and other expenses used to calculate the net taxable value. Kinder Morgan CO_2 paid the retroactive tax bills under protest and filed petitions for a refund of the taxes paid under protest. On February 6, 2012, the Montezuma County Board of County Commissioners denied the refund petitions, and we appealed to the Colorado Board of Assessment Appeals. A hearing on this matter is presently scheduled to occur in the second quarter of 2013.

Other

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2's payments on carbon dioxide produced from the McElmo Dome and Bravo Dome units are currently ongoing. These audits and inquiries involve federal agencies, the states of Colorado and New Mexico, and county taxing authorities in the state of Colorado.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and 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 intends to appeal the judge's determination, but if that determination is upheld, SFPP would owe approximately $75 million in back rent. Accordingly, during 2011, we increased our rights-of-way liability to cover this liability amount. In addition, the judge determined that UPRR is entitled to an estimated $20 million for interest on the outstanding back rent liability. We believe the award of interest is without merit and we are pursuing our appellate rights.

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 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. SFPP is evaluating 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 KMBT. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the United States 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. On or about June 1, 2012, RG Steel filed for bankruptcy in Case No. 12-11669 in the United States Bankruptcy Court for the District of Delaware; consequently, the trial date has been postponed indefinitely.

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.

Perth Amboy, New Jersey Tank Release

On October 17, 2012, the PHMSA issued a Final Order to KMLT related to an October 28, 2009 tank release from our Perth Amboy, New Jersey liquids terminal. No product left the company's property, and additionally, there were no injuries, no impact to the adjacent community or public, and no fire as a result of the release. KMLT paid the penalty of less than $1 million and is in the process of implementing the compliance order requirements in the Final Order.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and were no injuries associated with the incident. We immediately began clean up operations in coordination with federal, state and local agencies. The cause of the incident is outside force damage. The incident is under investigation by the PHMSA, U.S. EPA and the Florida Department of Environmental Protection.

General

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is reasonably possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date and the reserves we have established, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. As of December 31, 2012 and December 31, 2011, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $310 million and $332 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

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 NJDEP sued Occidental Chemical and others under the New Jersey Spill Act for contamination in the Newark Bay Complex including numerous waterways and rivers. Occidental et al. then brought in approximately 300 third party defendants for contribution. NJDEP claimed damages related to forty years of discharges of TCDD (a form of dioxin), DDT and "other hazardous substances." GATX Terminals Corporation (n/k/a/ KMLT) was brought in 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. This case was filed against third party defendants in 2009. The judge issued his trial plan for this case during the first quarter of 2011. According to the trial plan, the judge allowed the State to file summary judgment motions against Occidental, Maxus and Tierra on liability issues immediately. Numerous third party defendants, as part of a joint defense group of which KMLT is a member, filed motions to dismiss, which were denied, and now have filed interim appeals from those motions. The appeals court panel heard oral arguments on these motions to dismiss in March 2012 and issued a ruling denying these motions in June 2012. The appellants have filed appeals to the New Jersey Supreme Court regarding this lower court ruling and denied the appeals. Maxus/Tierra's claims against the third party defendants are set to be tried in April 2013 with damages to be tried in September 2013. KMLT, as part of a defense group, has begun settlement negotiations with the NJDEP.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the U.S. EPA sent out 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 U.S. 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. We are participating in the allocation process on behalf of both KMLT and KMBT. Each entity has two facilities located in Portland Harbor. We expect the allocation to conclude in 2013 or 2014, depending upon when the U.S. EPA issues its 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 against a number of defendants by a water purveyor whose wells have allegedly been contaminated due to the presence of a number of contaminants. The Roosevelt Irrigation District is seeking up to $175 million from approximately 70 defendants. The plume of contaminants has traveled under Kinder Morgan's Phoenix Terminal. The plaintiffs have advanced a novel theory that the releases of petroleum from the Phoenix Terminal (which are exempt under the petroleum exclusion under CERCLA) have facilitated the natural degradation of certain hazardous substances and thereby have resulted in a release of hazardous substances regulated under CERCLA. We are part of a joint defense group consisting of other terminal operators at the Phoenix Terminal including Chevron, BP, Salt River Project, Shell and a number of others, collectively referred to as the terminal defendants. Together, we filed a motion to dismiss all claims based on the petroleum exclusion under CERCLA. This case was assigned to a new judge, who has deemed all previous motions withdrawn and will grant leave to re-file such motions at a later date. We plan to re-file the motion to dismiss as well as numerous summary judgment motions as the judge allows.

Casper and Douglas, U.S. EPA Notice of Violation

In March 2011, the U.S. EPA conducted inspections of several environmental programs at the Douglas and Casper Gas Plants in Wyoming. In June 2011, we received two letters from the U.S. EPA alleging violations at both gas plants of the Risk Management Program requirements under the Clean Air Act. In September 2012, we entered into Combined Complaint and Consent Agreements and paid a monetary penalty of $158,000 for each plant to resolve these issues.

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 is 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. The lawsuit was stayed beginning in 2009 and remains stayed through the next case management conference in March 2013. During the stay, the parties deemed responsible by the local regulatory agency (including the City of Los Angeles) have worked with that agency concerning the scope of the required cleanup and have now completed a sampling and testing program at the site. We anticipate that cleanup activities at the site will begin in the Spring of 2013. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including KMLT, have appealed those cleanup goals to the state water board. The state water board has not yet taken any action with regard to our appeal petitions.

Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed $10 million, and that the plaintiff's past damages exceed $2 million. No trial date has yet been set. We are in settlement negotiations with the Port of Los Angeles.

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 Corp. from 1989 through September 2000, and later owned by

Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, and it too is 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 seeking to bring Support Terminals/ Plains into the case. Support Terminals/Plains filed motions to dismiss the third party complaints, which were denied. Support Terminals/Plains is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases. All private parties and the state participated in two mediation conferences in 2010.

In mid 2011, KMLT and Plains Products entered into an agreement in principle with the NJDEP for settlement of the state's alleged natural resource damages claim. The parties then entered into a Consent Judgment which was subject to public notice and comment and court approval. 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 a settlement agreement that settled each parties' 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. Now Plains will begin conducting remediation activities at the site and KMLT will provide oversight and 50% of the costs. The settlement with the state does not resolve the original complaint brought by ExxonMobil. KMLT and Plains received a settlement demand from ExxonMobil in the amount of approximately $1 million for past costs related to the remediation at the Paulsboro facility. Plains and KMLT have provided ExxonMobil a counteroffer. The parties are now very close to settlement. There is no trial date set.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States 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.

In accordance with the Case Management Order, the parties filed their respective summary adjudication motions and motions to exclude experts on June 29, 2012. On November 29, 2012, the Court issued a Notice of Tentative Rulings on the parties' pending motions. The Court tentatively granted our motions to exclude certain of the City's proposed expert witnesses, 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. 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.

Kinder Morgan, U.S. EPA Section 114 Information Request

On January 8, 2010, KMI, on behalf of Natural Gas Pipeline Company of America LLC, Horizon Pipeline Company and Rockies Express, received a Clean Air Act Section 114 information request from the U.S. EPA, Region V. This information request requires that the three affiliated companies provide the U.S. EPA with air permit and various other information related to their natural gas pipeline compressor station operations located in Illinois, Indiana, and Ohio. The affiliated companies have responded to the request and believe the relevant natural gas compressor station operations are in substantial compliance with applicable air quality laws and regulations.

Administrative Agreement with the U.S. EPA

In April 2011, we received Notices of Proposed Debarment from the U.S. EPA SDD. The Notices proposed the debarment of us (along with four of our subsidiaries), KMI, Kinder Morgan G.P., Inc., and Kinder Morgan Management, LLC, from participation in future federal contracting and assistance activities. The Notices alleged that certain of the respondents' past environmental violations indicated a lack of present responsibility warranting debarment.

In May 2012, we reached an administrative agreement with the U.S. EPA which resolved this matter without the debarment of any Kinder Morgan entities. The agreement requires independent monitoring of our Environmental Compliance and Ethics Programs, independent auditing of our facilities, enhanced training and notification requirements, and certain enhancements to our operational and compliance policies and procedures. We take environmental compliance very seriously and expect to comply with all aspects of this agreement.

TGP, PHMSA Notice of Violation

On April 25, 2012, the PHMSA issued an NOPV against TGP proposing $118,500 in penalties for alleged violations discovered during an inspection prior to Kinder Morgan's ownership of TGP. We responded to the NOPV and paid the penalty.

Other Environmental

We 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 carbon dioxide 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 negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or cash flows.

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, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

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 will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of December 31, 2012, we have accrued an environmental reserve of $119 million. As of December 31, 2011, our environmental reserve totaled $75 million. In addition, as of December 31, 2011, we recorded a receivable of $5 million for expected environmental cost recoveries that were deemed probable, and these receivables were settled during 2012. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. 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 cash flows.

17. Regulatory Matters

The tariffs we charge for transportation on our interstate common carrier pipelines are subject to rate regulation by the FERC, under the Interstate Commerce Act. The Interstate Commerce Act requires, among other things, that interstate petroleum products pipeline rates be just and reasonable and nondiscriminatory. Pursuant to FERC Order No. 561, effective January 1, 1995, interstate petroleum products pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. FERC Order No. 561-A, affirming and clarifying Order No. 561, expanded the circumstances under which interstate petroleum products pipelines may employ cost-of-service ratemaking in lieu of the indexing methodology, effective January 1, 1995. For each of the years ended December 31, 2012, 2011 and 2010, the application of the indexing methodology did not significantly affect tariff rates on our interstate petroleum products pipelines.

Below is a brief description of our ongoing regulatory matters, including any material developments that occurred during 2012.

TGP's Proposed Sale of Production Area Facilities

On July 26, 2012, TGP filed an application with the FERC seeking authority to abandon by sale certain offshore and onshore supply facilities as well as a related offer of settlement that addresses the proposed rate and accounting treatment associated with the sale. The offer of settlement provides for a rate adjustment to TGP's maximum tariff rates upon the transfer of the assets and the establishment of a regulatory asset for a portion of the unrecovered net book value of the facilities to be sold. The sale is conditioned on approval by the FERC of both the requested abandonment authorization and offer of settlement. As of December 31, 2012, these assets totaled $32 million and are included within "Assets held for sale" in our accompanying consolidated balance sheet. Additionally, we have recorded an approximately $113 million regulatory asset, which is included within "Deferred charges and other assets" in our accompanying consolidated balance sheet as of December 31, 2012, for the portion of the loss that we expect to recover through TGP's jurisdictional transportation rates as outlined in the FERC filing.

TGP Northeast Supply Diversification Project (Docket No. CP11-30-000)

On September 10, 2011, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in northern Pennsylvania and western New York along with an associated lease of transportation capacity from Dominion Transmission, Inc. in order to provide incremental firm transportation service to shippers of approximately 245 million cubic feet per day of natural gas produced in the Marcellus Shale supply area to northeast markets. The estimated capital cost of the project is approximately $55 million and the capacity is fully subscribed under long-term contracts. The project was completed and placed into service on November 1, 2012.

TGP Northeast Upgrade Project (Docket No. CP11-161-000)

On May 29, 2012, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in Pennsylvania and New Jersey that will provide needed infrastructure to support continued development of Marcellus shale natural gas production and increase TGP's delivery capacity in the region by approximately 620 million cubic feet per day. The estimated capital cost of the project is approximately $450 million and the capacity is fully subscribed under long term contracts. With no stay of construction granted, and subject to receipt of final FERC and other regulatory agency approvals, the project is anticipated to be placed in service in November 1, 2013.

TGP MPP Project (Docket No. CP12-28-000)

On August 9, 2012, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in northwestern Pennsylvania that will provide needed infrastructure to support continued development of Marcellus shale natural gas production and increase TGP's delivery capacity in the region by approximately 240 million cubic feet per day. The estimated capital cost of the project is approximately $86 million, and the capacity is fully subscribed under long term contracts. The Marcellus Pooling project is anticipated to be placed in service in November 1, 2013.

TGP Rose Lake Expansion Project (Docket No. CP13-03-000)

On October 10, 2012, TGP filed an application with the FERC requesting authority to expand its pipeline capacity in northern Pennsylvania through the installation and modification of new and existing compression facilities that will result in increased capacity of approximately 225 million cubic feet per day and will improve the efficiency and reduce emissions by replacing certain older existing compression facilities. The project will further support continued development of Marcellus shale natural gas production in the region. The estimated capital cost of the project is approximately $92 million and the capacity is fully subscribed under long term contracts. The project is anticipated to be placed in service in November 1, 2014.

EPNG Sierrita Natural Gas Pipeline LLC Project

On February 7, 2013, our wholly-owned subsidiary Sierrita Gas Pipeline LLC (a newly created interstate natural gas pipeline company) filed an application with the FERC to build a new 60-mile, 36-inch diameter pipeline that would extend from EPNG's existing south mainlines (near the City of Tucson, Arizona) to the U.S.-Mexico border (near the Town of Sasabe, Arizona). At an approximate cost of $200 million, the new Sierrita Pipeline would interconnect with a new 36-inch diameter natural gas pipeline to be built in Mexico. The new facilities will provide approximately 200 million cubic feet per day of firm natural gas transportation capacity. Sierrita Gas Pipeline LLC entered into a 25-year transportation service agreement for the entire capacity. Pending FERC approval, the construction of the Sierrita Pipeline would begin as early as the first quarter of 2014. We anticipate that the pipeline would be placed into service in the fall of 2014.

Products Pipelines and Natural Gas Pipelines Regulatory Proceedings

For information on our pipeline regulatory proceedings, see Note 16 "Litigation, Environmental and Other Contingencies —Federal Energy Regulatory Commission Proceedings" and "—California Public Utilities Commission Proceedings."

18. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates (ASU) that we adopted and that became effective January 1, 2012 (including ASU No. 2011-8, "Intangibles—Goodwill and Other (Topic 350): Testing Goodwill for Impairment") had a material impact on our consolidated financial statements.

ASU No. 2011-11

On December 16, 2011, the Financial Accounting Standards Board, referred to in this note as the FASB, issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." This ASU requires disclosures to provide information to help reconcile differences in the offsetting requirements under U.S. Generally Accepted Accounting Principles and International Financial Reporting Standards. The disclosure requirements of this ASU mandate that entities disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an enforceable master netting arrangement or similar agreement. ASU No. 2011-11 also requires disclosure of collateral received and posted in connection with master netting arrangements or similar arrangements. The scope of this ASU includes derivative contracts, repurchase agreements, and securities borrowing and lending arrangements, and all disclosures provided by the amendments of ASU No. 2011-11 are required to be provided retrospectively for all comparative periods presented. For us, ASU No. 2011-11 was effective January 1, 2013, and the adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

ASU No. 2012-02

On July 27, 2012, the FASB issued ASU No. 2012-02, "Intangibles-Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment." This ASU allows an entity the option to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not (that is, a likelihood of more than 50%) that an indefinite-lived intangible asset other than goodwill is impaired. If, after this assessment, an entity concludes that it is not more likely than not that the indefinite-lived intangible asset is impaired, the entity is not required to take further action. However, if an entity concludes otherwise, then it is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test prescribed by current accounting principles. Moreover, an entity can bypass the qualitative assessment for any indefinite-lived intangible asset in any period and proceed directly to the quantitative impairment test, and then resume performing the qualitative assessment in any subsequent period. For us, ASU

No. 2012-02 was effective January 1, 2013, and the adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

ASU No. 2013-01

On January 31, 2013, the FASB issued ASU No. 2013-01, "Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities." This ASU amends and clarifies the scope of the balance sheet offsetting disclosures prescribed in ASU No. 2011-11 (described above). Specifically, ASU No. 2013-01 limits the scope of ASU No. 2011-11's required disclosures to the following financial instruments, to the extent that they are offset in the financial statements or subject to an enforceable master netting arrangement or similar agreement: (i) recognized derivative contracts accounted for under ASC 815, "Derivatives and Hedging;" (ii) repurchase agreements and reverse repurchase agreements; and (iii) securities borrowing and securities lending transactions. For us, ASU No. 2013-01 was effective January 1, 2013, and the adoption of this ASU is not expected to have a material impact on our consolidated financial statements.

ASU No. 2013-02

On February 5, 2013, the FASB issued ASU No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This ASU amends and clarifies the disclosure requirements prescribed in ASU No. 2011-05, "Comprehensive Income (Topic 220): Presentation of Comprehensive Income." ASU No. 2013-02 requires that entities present information about reclassification adjustments from accumulated other comprehensive income in their annual financial statements in a single note or on the face of the financial statements. Public entities will also have to provide this information in their interim financial statements. Specifically, entities must present, either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source and the income statement line items affected by the reclassification. If a component is not required to be reclassified to net income in its entirety, entities would instead cross reference to the related footnote for additional information. For us, ASU No. 2013-02 was effective January 1, 2013, and we are currently reviewing the effect of this ASU.

Supplemental Selected Quarterly Financial Data (Unaudited)

	Operating Revenues	Operating Income	Income from Continuing Operations	Income from Discontinued Operations	Net Income
			(In millions)		
2012					
First Quarter(a)	$ 1,848	$ 566	$ 480	$ (272)	$ 208
Second Quarter(b)	1,951	522	425	(279)	146
Third Quarter(c)	2,333	598	514	(131)	383
Fourth Quarter	2,510	654	606	13	619
2011					
First Quarter(d)	$ 1,917	$ 378	$ 291	$ 50	$ 341
Second Quarter(e)	1,938	270	192	40	232
Third Quarter(f)	2,111	415	161	55	216
Fourth Quarter	1,923	494	423	56	479

(a) First quarter 2012 includes a $322 million discontinued operations loss from the remeasurement of our FTC Natural Gas Pipelines disposal group to fair value.

(b) Second quarter 2012 includes a $327 million discontinued operations loss from the remeasurement of our FTC Natural Gas Pipelines disposal group to fair value.

(c) Third quarter 2012 includes a $178 million discontinued operations loss from costs to sell and the remeasurement of our FTC Natural Gas Pipelines disposal group to fair value.

(d) First quarter 2011 includes an $87 million increase in expense allocated to us from KMI and associated with a one-time special cash bonus payment paid to non-senior management employees in May 2011; however, we do not have any obligation, nor did we pay any amounts related to this expense.

(e) Second quarter 2011 includes a $165 million increase in expense associated with rate case liability adjustments.

(f) Third quarter 2011 includes a $167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value, and a $69 million increase in expense primarily associated with rights-of-way lease payment liability adjustments.

	Limited Partners' Interest in:		
	Income from Continuing Operations	**Income from Discontinued Operations**	**Net Income**
Limited Partners' income (loss) per unit:			
2012			
First Quarter	$ 0.46	$ (0.79)	$ (0.33)
Second Quarter	0.27	(0.80)	(0.53)
Third Quarter	0.30	(0.36)	(0.06)
Fourth Quarter	0.61	0.03	0.64
2011			
First Quarter	$ 0.03	$ 0.15	$ 0.18
Second Quarter	(0.31)	0.12	(0.19)
Third Quarter	(0.41)	0.16	(0.25)
Fourth Quarter	0.35	0.16	0.51

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Operating statistics from our oil and gas producing activities for each of the years 2012, 2011 and 2010 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2012	2011	2010
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$ 16.44	$ 15.37	$ 12.58
Crude oil production (MBbl/d)	35.0	34.2	35.5
SACROC crude oil production (MBbl/d)	24.1	23.8	24.3
Yates crude oil production (MBbl/d)	9.3	9.6	10.7
Natural gas liquids production (MBbl/d)(d)	3.9	3.5	5.8
Natural gas liquids production from gas plants(MBbl/d)(e)	5.6	5.0	4.2
Total natural gas liquids production(MBbl/d)	9.5	8.5	10.0
SACROC natural gas liquids production (MBbl/d)(d)	3.7	3.3	5.5
Yates natural gas liquids production (MBbl/d)(d)	0.2	0.2	0.2
Natural gas production (MMcf/d)(d)(f)	1.2	1.5	1.4
Natural gas production from gas plants(MMcf/d)(e)(f)	0.7	0.5	1.9
Total natural gas production(MMcf/d)(f)	1.9	2.0	3.3
Yates natural gas production (MMcf/d)(d)(f)	1.1	1.4	1.3
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$ 87.72	$ 69.73	$ 59.96
Natural gas liquids price per Bbl(g)	$ 51.79	$ 65.65	$ 50.34
Natural gas price per Mcf(h)	$ 2.58	$ 3.86	$ 4.08
Total natural gas liquids price per Bbl(e)	$ 50.95	$ 65.61	$ 51.03
Total natural gas price per Mcf(e)	$ 2.72	$ 3.76	$ 4.10
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$ 89.91	$ 92.61	$ 76.93
Natural gas liquids price per Bbl(g)	$ 51.79	$ 65.65	$ 50.34
Natural gas price per Mcf(h)	$ 2.58	$ 3.86	$ 4.08

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. 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 our ownership in processing plants and third party processing agreements.

(f) Excludes natural gas production used as fuel.

Table of Contents

(g) Hedge gains/losses for crude oil and natural gas liquids 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,		
	2012	**2011**	**2010**
Consolidated Companies(a)			
Wells and equipment, facilities and other	$ 3,444	$ 3,104	$ 2,677
Leasehold	348	352	352
Total proved oil and gas properties	3,792	3,456	3,029
Unproved property(b)	8	34	88
Accumulated depreciation and depletion	(2,659)	(2,288)	(1,901)
Net capitalized costs	$ 1,141	$ 1,202	$ 1,216

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries. Includes capitalized asset retirement costs and associated accumulated depreciation.

(b) The unproved amounts consist of capitalized costs related to the Katz field unit, which is in the initial stages of the carbon dioxide flooding operation.

For each of the years 2012, 2011 and 2010, our costs incurred for property acquisition, exploration and development were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
	2012	**2011**	**2010**
Consolidated Companies(a)			
Development	310	373	326

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries. During 2012 and 2011, we spent $71 million and $89 million, respectively, on development costs related to the Katz field unit, which was in the initial stages of the carbon dioxide flooding operation. As of December 31, 2012, capitalized costs related to unproved property for the Katz unit was $8 million. No exploration costs were incurred for the periods reported.

Our results of operations from oil and gas producing activities for each of the years 2012, 2011 and 2010 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2012	2011	2010
Consolidated Companies(a)			
Revenues(b)	$ 1,235	$ 993	$ 903
Expenses:			
Production costs	288	246	229
Other operating expenses(c)	77	79	63
Depreciation, depletion and amortization expenses	387	394	406
Total expenses	752	719	698
Results of operations for oil and gas producing activities	$ 483	$ 274	$ 205

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries.

(b) Revenues include losses attributable to our hedging contracts of $28 million, $285 million and $220 million for each of the years ended December 31, 2012, 2011 and 2010, respectively.

(c) Consists primarily of carbon dioxide 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 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 27 years of practical experience in petroleum engineering, with over 15 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 23 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.

Our employee who is primarily responsible for overseeing Netherland, Sewell & Associates, Inc.'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 25 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 becomes 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, natural gas liquids 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, our CO_2 business segment managers and our Vice President (President, CO_2) review all significant reserves changes and all new proved developed and undeveloped reserves additions; and
- our CO_2 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, 2012.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids 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, natural gas liquids 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, 2010, we had 56.4 million barrels of crude oil and 2.2 million barrels of natural gas liquids classified as proved developed reserves. Also as of year end 2010, we had 27.8 million barrels of crude oil and 2.6 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2010 were 84.2 million barrels of crude oil and 4.9 million barrels of natural gas liquids.

During 2011, production from the fields totaled 12.5 million barrels of crude oil and 1.3 million barrels of natural gas liquids. In addition, we incurred $373 million in capital costs, which resulted in the development of 7.3 million barrels of crude oil and 0.9 million barrels of natural gas liquids and their transfer from the proved undeveloped category to the proved developed category. We also developed 3.0 million barrels of crude oil with the development of the Katz (Strawn) unit CO_2 flood, where the produced natural gas containing natural gas liquids is injected with the CO_2. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 26.2% of crude oil and 35.2% of natural gas liquids from the proved undeveloped reserves reported as of December 31, 2010 to the proved developed classification of reserves reported as of December 31, 2011. The developed reserves for the Katz (Strawn) unit CO_2 flood represent 5.4% of proved developed reserves.

Also during 2011, previous estimates of proved developed reserves were revised upwards by 1.4 million barrels of crude oil, and proved undeveloped reserves were revised upward by 3.3 million barrels of crude oil and 0.6 million barrels of natural gas liquids. These revisions are attributed to utilizing a higher prescribed oil price basis ($92.71 per barrel for year end 2011 versus $75.96 per barrel for year end 2010) and higher projected CO_2 flood recoveries resulting from updated performance at SACROC used to calculate reserves. All natural gas reserves are associated with crude oil production and are not impacted by natural gas pricing.

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 decreasing from 33.9% at year end 2010 to 31.0% at year end 2011. After giving effect to production and revisions to previous estimates during 2011, total proved reserves of crude oil decreased by 4.7 million barrels and total proved reserves of natural gas liquids decreased by 0.7 million barrels.

As of December 31, 2011, we had 55.7 million barrels of crude oil and 1.8 million barrels of natural gas liquids classified as proved developed reserves. Also, as of year end 2011, we had 23.8 million barrels of crude oil and 2.3 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2011, were 79.4 million barrels of crude oil and 4.1 million barrels of natural gas liquids.

During 2012, production from the fields totaled 12.8 million barrels of crude oil and 1.4 million barrels of natural gas liquids. For 2012, we incurred $353 million in capital costs, and this capital investment resulted in the development of 6.0 million barrels of crude oil and 1.8 million barrels of natural gas liquids and their transfer from the proved undeveloped category to the proved developed category. During 2012, we sold our interest in the Claytonville Canyon Sand Unit which reduced proved developed reserves by 0.2 million barrels 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 natural gas liquids 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 million barrels of crude oil and 0.2 million barrels of natural gas liquids, and proved undeveloped reserves were revised upward by 11.2 million barrels of crude oil and 3.0 million barrels of natural gas liquids. These revisions are attributed to utilizing higher projected CO_2 flood recoveries resulting from updated performance at SACROC used to calculate reserves. There are 2.6 million barrels of crude oil reserves attributed to future development of the Katz (Strawn) unit CO_2 flood where the produced gas containing natural gas liquids 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 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 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 million barrels and total proved reserves of natural gas liquids increased by 1.8 million barrels.

As of December 31, 2012, we had 53.0 million barrels of crude oil and 2.4 million barrels of natural gas liquids classified as proved developed reserves. Also, as of year end 2012, we had 28.9 million barrels of crude oil and 3.5 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2012, were 82.0 million barrels of crude oil and 6.0 million barrels of natural gas liquids. We currently expect that the proved undeveloped reserves we report as of December 31, 2012 will be developed within the next five years.

During 2012, we filed estimates of our oil and gas reserves for the year 2011 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, 2012, of proved crude oil, natural gas liquids and natural gas reserves, prepared by Netherland, Sewell & Associates, Inc. (independent oil and gas consultants), of Kinder Morgan CO_2 Company, L.P. 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 U.S. Securities and Exchange Commission (SEC).

Reserve Quantity Information

	Consolidated Companies(a)		
	Crude Oil (MBbls)	**NGLs (MBbls)**	**Natural Gas (MMcf)(b)**
Proved developed and undeveloped reserves:			
As of December 31, 2009	80,844	5,920	698
Revisions of previous estimates(c)	16,294	1,059	2,923
Production	(12,962)	(2,116)	(523)
As of December 31, 2010	84,176	4,863	3,098
Revisions of previous estimates(d)	4,719	567	687
Improved recovery(e)	3,018	—	—
Production	(12,466)	(1,285)	(544)
As of December 31, 2011	79,447	4,145	3,241
Revisions of previous estimates(f)	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
Proved developed reserves:			
As of December 31, 2010	56,423	2,221	3,098
As of December 31, 2011	55,652	1,823	3,241
As of December 31, 2012	53,006	2,433	7,539
Proved undeveloped reserves:			
As of December 31, 2010	27,753	2,642	—
As of December 31, 2011	23,795	2,322	—
As of December 31, 2012	28,944	3,543	—

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. 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 and a change in methodology used for the Yates Field Unit. In 2010, our third party oil and gas consultants revised the methodology used to estimate reserves for our Yates Field Unit in order to take greater account of the reservoir mechanisms associated with carbon dioxide injection.

(d) Predominantly due to higher product prices used to determine reserve volumes.

(e) Represents volumes added with the development of the Katz (Strawn) unit carbon dioxide flood.

(f) Predominantly due to higher CO_2 flood recoveries based on updated performance at the SACROC Unit.

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, natural gas liquids 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.

Our 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,		
	2012	**2011**	**2010**
Consolidated Companies(a)			
Future cash inflows from production	$ 7,807	$ 7,648	$ 6,666
Future production costs	(2,923)	(2,806)	(2,388)
Future development costs(b)	(1,011)	(1,443)	(1,434)
Undiscounted future net cash flows	3,873	3,399	2,844
10% annual discount	(1,168)	(1,205)	(946)
Standardized measure of discounted future net cash flows	$ 2,705	$ 2,194	$ 1,898

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries.

(b) Includes abandonment costs.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	As of December 31,		
	2012	**2011**	**2010**
Consolidated Companies(a)			
Present value as of January 1	$ 2,194	$ 1,898	$ 1,263
Changes during the year:			
Revenues less production and other costs(b)	(895)	(949)	(828)
Net changes in prices, production and other costs(b)	(88)	697	890
Development costs incurred	353	416	248
Net changes in future development costs	64	(317)	(296)
Improved recovery	—	10	—
Extensions and Discoveries(c)	5	—	—
Sales of Reserves in Place(d)	(5)	—	—
Revisions of previous quantity estimates(e)	871	257	494
Accretion of discount	206	182	127
Net change for the year	511	296	635
Present value as of December 31	$ 2,705	$ 2,194	$ 1,898

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries.

(b) Excludes the effect of losses attributable to our hedging contracts of $28 million, $285 million and $220 million for each of the years ended December 31, 2012, 2011 and 2010, respectively.

(c) Primarily due to the extension of the SACROC Unit.

(d) Sale of the Claytonville Field Unit.

(e) 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 carbon dioxide flood. 2011 revisions were primarily due to higher product prices used to determine reserve volumes and the addition of the Katz (Strawn) carbon dioxide flood. 2010 revisions were primarily due to higher product prices used to determine reserve volumes and the change in methodology discussed above.

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 ENERGY PARTNERS, L.P.
Registrant (a Delaware Limited Partnership)

By: **KINDER MORGAN G.P., INC.,**
Its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC,** the Delegate of Kinder Morgan G.P., Inc.

By: /s/ KIMBERLY A. DANG

Kimberly A. Dang,
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 19, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal financial officer and principal accounting officer)	February 19, 2013
/s/ RICHARD D. KINDER Richard D. Kinder	Chairman of the Board and Chief Executive Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal executive officer)	February 19, 2013
/s/ TED A. GARDNER Ted A. Gardner	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 19, 2013
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 19, 2013
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 19, 2013
/s/ C. PARK SHAPER C. Park Shaper	Director and President of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 19, 2013